Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Gas Integrity Management Inspection Manual

Inspection Protocols With Supplemental Guidance

January 1, 2008

Notice: Inspection documentation, including completed protocol forms, are for internal use only by federal or state pipeline safety regulators. Do not distribute or otherwise disclose such material outside of the state or federal pipeline regulatory organizations.

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 and is intended to be used solely as a reference by PHMSA personnel. 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. In the event of a conflict between this document and any regulation, the document would not be 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 to the implementation scenarios presented in the materials. Alternative approaches are not precluded if they satisfy the requirements of the applicable regulation(s).

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 and colleagues 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.

PHMSA Gas Integrity Management Protocols with Guidance

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A.01 Program Requirements

Verify that the methods defined in §192.903 High Consequence Area (1) and/or §192.903 High Consequence Area (2) are applied to each pipeline for the identification of high consequence areas. [§192.905(a)]

A.01 *Supplemental Guidance:*

- This Protocol establishes requirements for the application of Method 1 and Method 2 to identify pipeline segments that may impact an HCA.
- Protocol A.01.a, A.01.b, and A.01.c establish program requirements for HCA identification that should be included in an operator's IMP. Protocol A.01.d reflects the rule requirement that HCAs be identified by December 17, 2004. Refer to the following FAQs:
    - FAQ-14 clarifies that all High Consequence Areas (HCAs) must be identified as part of an operator's initial integrity management framework, which must be completed by December 17, 2004.
    - FAQ-21 states that non-pipe elements of a pipeline system in HCAs (e.g., compressor stations) must be identified by December 17, 2004.
    - FAQ-84 clarifies the integrity assessment provisions of the rule. The rule only applies to line pipe, including pipe that may be within the boundaries of facilities (e.g., compressor stations, metering stations). The other provisions of the rule apply to the equipment in these facilities (e.g., compressors) if the locations meet the criteria to be designated HCAs. Thus, operators must consider facilities when establishing potential impact circles (the diameter of the pipe into/out of the equipment should be used), and should include in their integrity management program processes for addressing these facilities.
- FAQ-150 addresses the requirements that must be met if an operator has no piping located in HCA, i.e., no covered segments. As described therein, the operator must have completed an evaluation to determine that it has no piping in HCA. The operator must have a process to periodically review this evaluation to determine that changes (e.g., new construction along the pipeline) have not introduced an HCA. The process for performing this evaluation, and for reviewing/revising it periodically, is the same whether or not HCAs are present. The lack of HCAs is the conclusion, but that conclusion cannot be reached without performing the evaluation. Thus, this Protocol would apply to operators without piping in HCA in the same manner that it applies to those that do. The documentation expected of operators without piping in HCA would be the same. These operators need not have a written IM plan, and the remaining Protocols would not apply except H.03.b, which addresses requirements in §192.935(d) that are applicable to pipeline in Class 3 and 4 areas that is not in an HCA.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A1, Protocol A.1

A.01.a. Verify the operator's integrity management program includes documented processes on how to implement methods (1) and (2) in order to identify high consequence areas. [§192.905(a)]

A.01.a. Supplemental Guidance:

- The Gas Integrity Management Rule, Section 903 Definitions, establishes 2 methods that may be used for HCA identification. An operator may use either method, or both, for identification of HCAs. Refer to the following FAQs:
    - FAQ-172 states that operators may designate an entire segment, or their entire pipeline, as covered by the rule.
    - FAQ-192 also clarifies that an operator with only a limited amount of pipeline can elect to treat its entire pipeline as an HCA.
- Operators' integrity management programs should have documented descriptions of how HCA identification is implemented for their pipeline.
- It is expected that the integrity management program will describe how the HCA identification requirements are implemented, roles and responsibilities for program implementation, and provide assurance that all of the operator's gas transmission pipeline system has been evaluated for HCA identification.
- FAQ-22 clarifies why is it important that operators know the specific characteristics of high consequence areas their pipelines traverse.

A.01.b. Verify that the operator's process requires that the method used for each portion of the pipeline system be documented. [§192.905(a)]

A.01.b. Supplemental Guidance:

- HCA identification program requirements allow the operator to use Method 1, Method 2, or a combination of either method. Operator program documentation should be reviewed to assure it specifies which methods or combination of methods are used for HCA identification. Documentation should also specify which pipeline segments were evaluated by which method.

A.01.c. Verify that the operator's integrity management program includes system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas. [§192.905(a)]

A.01.c. Supplemental Guidance:

- As part of the operator's integrity management program, piping system maps or other suitably detailed documentation should be available that shows the pipeline segments that are located in high consequence areas. As a corollary, the operator's documentation would also clearly demonstrate which pipeline segments are not in an HCA.
- It is expected that most large operators will utilize GIS or similar mapping software for segment identification. The operator should demonstrate its system and show graphically the overlay of HCAs with its pipeline system.
- For operators that do not use GIS or similar mapping software, it will be necessary to have the operator describe and/or demonstrate how it performed its HCA segment identification.
- For both GIS-based, and non-GIS-based, HCA identification processes, the operator should address how tolerances (or buffers on top of the calculated PIR) will be dealt with regarding accuracy of distance measurements to structures and the location of the pipeline centerline. It is recognized that GPS measurements and maps have some limitations on accuracy. The rule applies to pipelines, and distances from those pipelines, as they actually exist in the field.
    - FAQ-174 states that operators must consider the uncertainties in the distances they measure or infer when evaluating potential impact circles.

A.01.d. Review HCA records to verify that the operator completed identification of pipeline segments in high consequence areas by December 17, 2004. [§192.907 and §192.911(a)]

A.01.d. Supplemental Guidance:

- Review of an operator's gas integrity management program should include a review of records demonstrating that the operator completed identification of pipeline segments in high consequence areas by December 17, 2004.

A.02 Potential Impact Radius

Verify that the definition and use of potential impact radius for establishment of high consequence areas meets the requirements of §192.903. [§192.905(a)]

A.02 *Supplemental Guidance:*

- This Protocol establishes the requirements for determination of the Potential Impact Radius (PIR) surrounding an operator's pipeline. This protocol provides the formula for calculating the PIR and the requirement that the potential impact circle (PIC) extend axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle. These requirements should be verified as being a part of an operator's IMP.
- FAQ-15 provides the definition of covered segments and clarification on the axial extension of potential impact circles.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A2, Protocol A.2

A.02.a. Verify that the operator's formula for calculation of the potential impact radius is consistent with §192.903 requirements ($r = 0.69*(p*d^2)^{0.5}$) and that the pressure used in the formula is based on maximum allowable operating pressure (MAOP).

i. For gases other than natural gas, verify that the operator has documented processes for the use of ASME B31.8S-2004, Section 3.2 to calculate the impact radius formula [§192.903 Potential Impact Radius, §192.905(a)]

A.02.a. Supplemental Guidance:

- A range of PIR values has been calculated for a variety of pipeline diameters and MAOP combinations and are provided in Supplemental Guidance Appendix A.01, Table 1, Natural Gas Potential Impact Radius Rounded Up to the Nearest Foot (refer to Supplemental Guidance Appendix A.01, Bookmark A2a, Section A.2.a).
- Calculation must use MAOP (not actual or historical operating pressure). Refer to the following FAQs:
  - FAQ-16 states that maximum allowable operating pressure (in pounds per square inch) is to be used in PIR calculation.
  - FAQ-119 clarifies that normal operating pressure in potential impact circle calculations may not be used even if that pressure is significantly below MAOP
- FAQ-200 clarifies that pipelines that have components with different pressure ratings may use the most limiting (lowest) MAOP (i.e., the component that dictates the MAOP of the entire segment) in calculating the PIR for the entire segment. If the line is subsequently uprated, new PIRs would have to be calculated based on a higher MAOP.
- See Supplemental Guidance Appendix A.01, Bookmark Exhibit1, Exhibit 1, for derivation of the PIR formula for natural gas.

- FAQ-208 addresses consideration of flammable gases other than natural gas. For flammable gases other than natural gas, the rule requires operators to use ASME B31.8S-2004, Section 3.2 to derive the PIR equation. Refer to the following Baker report which establishes the PIR and basis for several other flammable gases.
    - TTO-13, Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas (Reference: TTO-13)
- The values established in the Baker report are provided below:

Summary of Potential Impact Radius Formula

Product	**PIR Formula**
Ethylene	$r = 1.04(pd^2)^{0.5}$
Hydrogen	$r = 0.47(pd^2)^{0.5}$
Natural Gas (Lean)	$r = 0.69(pd^2)^{0.5}$
Natural Gas (Rich)	$r = 0.73(pd^2)^{0.5}$
Syngas	$r = 0.49(pd^2)^{0.5}$

- Note that "rich gas" is considered to be a gas with a gross heat value of 1100 BTU/cubic foot or greater. TTO-13, Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas, Section 7.0 (Reference: TTO-13) concludes that a factor of 0.73 should be used in the PIR formula for "rich gas." ***Note also that INGAA has questioned the need to use the rich gas formula. They contend that rich gas is still "natural gas" and that the rule specifies use of 0.69 as the factor for natural gas in the PIR equation. PHMSA has concluded that it cannot require operators to use a different formula for rich gas given the language in the rule. Inspectors should inform operators that rich gas creates a larger impact circle and suggest that they use a different factor, but no enforcement action should be taken if the operator uses 0.69 until the rule is changed.***
- FAQ-3 states that operators of transmission pipelines transporting other gases must adjust the formula for determining potential impact circles to reflect the constant appropriate for the gas transported.
- FAQ-144 addresses nonflammable gases. Note that if nonflammable gases are transported by the operator, then the use of PIR concepts do not apply. Operators of pipelines carrying non-flammable gases must consider their entire pipelines as if they were in high consequence areas, or they may apply for a waiver to use another method that they may propose for defining HCAs. It is not appropriate for an operator to solely rely on the use of Class Locations for identifying HCAs as this would not meet Rule requirements (the Rule does not contemplate non-flammable gases). non-flammable gases can form toxic clouds that drift long distances from the pipeline and are not necessarily contained to the immediate vicinity of the pipeline. Refer to the following Baker report which establishes the PIR formula for several other nonflammable gases. Use of this approach by an operator would require submittal of a waiver and PHMSA review.
    - TTO-14, Derivation of Potential Impact Radius Formulae for Hazardous and/or Toxic Gases without Ignition (Reference: TTO-14)

A.02.b. In cases where potential impact circles are used to identify high consequence areas, verify that the program requires that high consequence areas include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain either an identified site or 20 or more buildings intended for human occupancy. [§192.903 High Consequence Area (3)]

A.02.b. Supplemental Guidance:

- FAQ-165 discusses the axial extension of the PIC. Examples of how the area around a pipeline may be determined to be a HCA are provided in Supplemental Guidance Appendix A.01, Bookmark Exhibit2, Exhibit 2, to demonstrate how the covered segment extends axially along the length of the pipeline to the edge of the bounding PIC to define each endpoint of the HCA.
- If any PIC includes any portion of the identified site (or 20 or more buildings intended for human occupancy) within its area, then the postulated point of failure of the "C-FER Circle" should be moved farther along both directions of the line until it does not intersect or touch the identified site. The HCA is then defined by the extension of the PIR axially in each direction along the pipeline.
    - FAQ-162 provides additional discussion regarding situations where only a small portion of a building meeting the HCA criteria is within the potential impact circle. Such building should be included in the building count consideration.
- Note that some operators may use a different, but equivalent, method of using PICs to define HCAs. The operator may draw the PIR from an identified site. Once the outer most PIC intersects with the pipeline are identified, then the PIR is extended down the pipeline from the outer most intersects for an additional distance equal to the PIR. This approach was observed at only one operator in the initial round of inspections but is likely to be seen again. This approach was used to facilitate their GIS computer model used for calculation of HCAs. The last two examples in Supplemental Guidance Appendix A.01, Bookmark Exhibit2, Exhibit 2, show this approach. This approach may also be applied when using the criteria of 20 or more dwellings intended for human occupancy. In that case, the HCA would be defined by 20 or more overlapping PIC intersections with the pipeline combined with the axial extension of the PIR from each end of the outer PIC intersections. This approach is equivalent to the method where the PIR is drawn out from the pipe.

A.03 Identified Sites

Verify that the operator's identification of identified sites includes the sources listed in §192.905(b) for those buildings or outside areas meeting the criteria specified by §192.903, and that the source of information selected is documented. [§192.903 Identified Sites, §192.905(b) and §192 Appendix E, I(c)]

A.03 *Supplemental Guidance:*

- This Protocol establishes the requirements for locating identified sites surrounding an operator's pipeline. Identified sites may be thought of as areas where people tend to congregate. As such, identified sites require additional consideration as a high consequence area (HCA). These requirements should be verified as being a part of an operator's IMP.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A3, Protocol A.3.

A.03.a. Identified sites must include the following: [§192.903 Identified Sites, §192.905(b)]

i. Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12 month period (days need not be consecutive),
ii. Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (days and weeks need not be consecutive), and

iii. Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to evacuate.

A.03.a. Supplemental Guidance:

- Inclusion of identified sites is intended to pick up population areas where people tend to gather which are not picked up through the Class location or PIC building count process. These could include isolated nursing homes, schools, campgrounds, off-shore platforms, or an operator's facilities that may be close enough to the pipeline to be at risk should there be a pipeline failure. Refer to the following FAQs:
    - FAQ-121 states that facilities occupied by an operator's employees be considered in identifying HCAs.
    - FAQ-151 states that an offshore platform associated with a transmission line must be considered as a possible "identified site."
    - FAQ-162 provides additional discussion regarding situations where only a small portion of a building meeting the HCA criteria is within the potential impact circle. Such building should be included in the building count consideration.
    - FAQ-163 provides discussion on why the length of an HCA segment may vary depending on how close to the pipeline an identified site is located.
    - FAQ-176 clarifies that a single home housing a disabled person in not considered an identified site.
- Verify that the operator's IMP includes the criteria for identified sites as listed in Protocol A.03.a.i, A.03.a.ii, and A.03.a.iii. Refer to the following FAQs:
    - FAQ-17 reiterates the rule criteria for identified sites.
    - FAQ-146 provides additional discussion of how commercial or industrial buildings are to be treated. Each structure/office/unit that is occupied in such a building should be counted in the analysis of 20 or more buildings within the impact circle.
- FAQ-145 and FAQ-143 discuss consideration of parking lots, roadways, and standing traffic. It is expected that roadways, potential standing traffic, parking lots, and other areas with transient or fluctuating use by people will be addressed by the operator.
- FAQ-182 clarifies that the criteria of "20 or more people" means that 20 or more people must be present simultaneously.
- FAQ-211 clarifies that the rule sets no minimum amount of time 20 persons must occupy an area in order to meet the definition of an identified site. The criteria refers to people that typically occupy the location in normal use.

A.03.b. Identified sites must be identified using the following sources of information: [§192.905(b)]

i. Information from routine operation and maintenance activities and input from public officials with safety or emergency response or planning responsibilities

ii. In the absence of public official input, the operator must use one of the following in order to identify an identified site:
    1. Visible markings such as signs, or
    2. Facility licensing or registration data on file with Federal, State, or local government agencies, or
    3. Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public.

A.03.b. Supplemental Guidance:

- PHMSA will expect operators to conduct a reasonable or good faith effort at identifying identified sites. The operator's IMP should include documentation describing the responsibilities for identifying identified sites and the methods used. Refer to the following FAQs:

  - FAQ-18 clarifies that operators are expected to make a reasonable effort to identify sites meeting the criteria for "identified sites".
  - FAQ-170 states that PHMSA expects an operator to make a good faith effort at establishing contact with public safety officials along portions of its pipeline containing HCAs.
- Guidance has been developed by PHMSA for clarifying the expectations for the identification of identified sites in the July 17, 2003 Advisory Bulletin ADB-03-03, Identified Sites as Part of High Consequence Areas for Gas Integrity Management Program (Reference: ADB-0303).
- FAQ-120 and FAQ-195 address an operator's interface with public officials. Operators are required to consult the entities responsible for safety and emergency response in the vicinity of the pipeline. The appropriate public officials are those with safety or emergency response or planning responsibilities who indicate to the operator that they know the location of sites that meet the criteria of Protocol A.03.a. These public officials may be local fire chief, Native American tribal officials, or the local emergency planning commission. The initial round of inspections has revealed that most operators are not receiving useful information from public official on identified sites. Operators may be able to improve on this source of information by providing the officials with copies of their system maps and / or by meeting face to face with the officials in an effort to improve communications and the understanding of what information is desired.
- In the absence of public official input, the operator must use at least ONE of the sources listed in Protocol A.03.b.ii. Inspectors should pay particular attention to situations where an operator has used the "Harris Directory" as one of its data sources in the search for identified sites. It is apparent that the locations in the Harris directory are often not accurate. If an exact address was not known, the Harris directory returns a geo-spatial location at the geographic center of the zip code, which is often many miles from the actual location of the facility.

A.04 Identification Using Class Locations (Method 1)

If the operator's integrity management program relies on §192.903 High Consequence Area definition (1) for identification of high consequence areas, verify compliance with the following:

A.04 *Supplemental Guidance:*

- This Protocol establishes the requirements for the use of Method 1, as defined by §192.903, to identify pipeline segments that potentially impact HCAs. Method 1 primarily relies on the use of existing Class Location unit data in conjunction with the identification of identified sites.
- FAQ-149 clarifies that all Class 3 and 4 areas may not be HCAs in cases where the operator uses Method 2. Therefore, all Class 3 and 4 areas are not necessarily HCAs.
- Requirements that are imposed on pipeline that operates at 80% SMYS under a waiver typically require that the entire pipeline subject to the waiver be treated as an HCA and assessed using ILI.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A4, Protocol A.4.

A.04.a. Verify the integrity management program includes Class 3 and Class 4 piping locations as high consequence areas consistent with the criteria of §192.5(b)(3), §192.5(b)(4), and §192.5(c). [§192.903 High Consequence Area (1)(i) and (ii)]

A.04.a. Supplemental Guidance:

- When an operator uses Method 1, one element of the HCA identification process is that all Class 3 and 4 Locations are considered to be HCA segment. Current Class Location data is to be used by the operator. Inspection should verify that the operator has in fact included all Class 3 and 4 Locations as HCA segments. Changes that may occur in Class Locations should be considered under Protocol A.06.

A.04.b. For Class 1 and Class 2 locations with the potential impact radius greater than 660 feet, verify the integrity management program includes piping locations as high consequence areas if the area within the associated potential impact circle contains 20 or more buildings intended for human occupancy.[§192.903 High Consequence Area (1)(iii)]

i. As an option for PIRs greater than 660 feet, the definition of high consequence area may have been based initially on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)]

Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]^2 or
Building Count within 200 meters = 20 x [200 (m) / PIR (m)]^2

1. If the option for use of a prorated number of buildings was used for identification of high consequence areas, verify that the prorated allowance was not used after December 17, 2006. [§192.903 High Consequence Area (4)]

A.04.b. Supplemental Guidance:

- When an operator uses Method 1 for HCA segment identification, Class 1 and 2 Location Units must be evaluated to identify HCA segments. This requirement would only apply for those Class 1 and 2 Locations with a PIR greater than 660 feet.
- The Rule allowed use of more stringent criteria using building counts for area within radius of 660 feet. Prorating may have been used under both Method 1 and Method 2 for identification of HCAs.
- The option for prorating was only available until December 17, 2006. Operators must now have collected actual building count data when the PIR is greater than 660 feet.
- For a large PIR (i.e., PIR greater than 660 feet), the initial prorating option meant that the building density for HCA applicability was reduced proportionally based on the ratio of the area of the PIC to that of the area of a PIC equal to 660 feet.

Refer to the following for how building counts may have been prorated for differing PIRs:

PIR (ft.)	Prorated Criterion for Buildings within 660 ft
700	**18**
800	**14**
900	**11**
1000	**9**
1200	**6**

- An example of prorating building count is included in Supplemental Guidance Appendix A.01, Bookmark Exhibit2, Exhibit 2.

A.04.c. Verify the program includes as a high consequence area, any area in Class 1 and Class 2 piping locations where the potential impact circle contains an identified site. [§192.903 High Consequence Area (1)(iv)]

A.04.c. Supplemental Guidance:

- When an operator uses Method 1, one element of the HCA identification process is to identify identified sites that lie within the potential impact circle of potential failures in Class 1 and 2 pipelines.
- FAQ-191 clarifies that the operator must consider identified sites on any Class 1 or 2 pipeline that the operator operates.

A.05 Identification Using Potential Impact Radius (Method 2)

If the operator's integrity management program relies on §192.903 High Consequence Area definition (2) for identification of high consequence areas, verify compliance with the following:

A.05 *Supplemental Guidance:*

- This Protocol establishes the requirements for the use of Method 2, as defined by §192.903, to identify pipeline segments that potentially impact HCAs. Method 2 does not make use of Class Location data. This methodology relies on identification of potential impact circles containing either 20 or more buildings intended for human occupancy or an Identified Site. Prorating of building counts was allowed until December 17, 2006.
- Operators of pipelines operating below 30% SMYS who use Method 2 should recognize that there are some requirements in §192.935(d) that apply to Class 3 and 4 pipelines that are not in HCAs.
- Note that some operators are using a software program called "Classworks" which does not display PICs. Inspectors may need to review several records to verify correct HCA identification when this program is used since its use might be more error prone. The "Class works" software is an old application developed for purposes of implementing Class Location requirements.
- Requirements that are imposed on pipeline that operates at 80% SMYS under a waiver typically require that the entire pipeline subject to the waiver be treated as an HCA and assessed using ILI.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A5, Protocol A.5.

A.05.a. For Class 1 and Class 2 locations with the potential impact radius greater than 660 feet, verify the integrity management program includes piping locations as high consequence areas if the area within the associated potential impact circle contains 20 or more buildings intended for human occupancy.[§192.903 High Consequence Area (1)(iii)]

ii. As an option for PIRs greater than 660 feet, the definition of high consequence area may have been based initially on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)]

Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]^2 or
Building Count within 200 meters = 20 x [200 (m) / PIR (m)]^2

2. If the option for use of a prorated number of buildings was used for identification of high consequence areas, verify that the prorated allowance was not used after December 17, 2006. [§192.903 High Consequence Area (4)]

A.05.a. Supplemental Guidance:

- When an operator uses Method 1 for HCA segment identification, Class 1 and 2 Location Units must be evaluated to identify HCA segments. This requirement would only apply for those Class 1 and 2 Locations with a PIR greater than 660 feet.
- The Rule allowed use of more stringent criteria using building counts for area within radius of 660 feet. Prorating may have been used under both Method 1 and Method 2 for identification of HCAs.
- The option for prorating was only available until December 17, 2006. Operators must now have collected actual building count data when the PIR is greater than 660 feet.
- For a large PIR (i.e., PIR greater than 660 feet), the initial prorating option meant that the building density for HCA applicability was reduced proportionally based on the ratio of the area of the PIC to that of the area of a PIC equal to 660 feet.

Refer to the following for how building counts may have been prorated for differing PIRs:

PIR (ft.)	Prorated Criterion for Buildings within 660 ft
700	**18**
800	**14**
900	**11**
1000	**9**
1200	**6**

- An example of prorating building count is included in Supplemental Guidance Appendix A.01, Bookmark Exhibit2, Exhibit 2.

A.05.b. Verify the program includes piping locations as high consequence areas if the area within the potential impact circle contains an identified site. [§192.903 High Consequence Area (2)(ii)]

A.05.b. Supplemental Guidance:

- When an operator uses Method 2, an element of the HCA identification process is to identify identified sites that lie within the potential impact circle of potential failures (regardless of the PIR size or pipeline Class location).

A.06 Identification and Evaluation of Newly Identified HCAs, Program Requirements

Review the operator's integrity management program to verify processes are in place for evaluation of new information that may show that a pipeline segment impacts a high consequence area. [§192.905(c)]

A.06 *Supplemental Guidance:*

- This Protocol establishes the requirements for identification of new or revised HCA segments that result from changing pipeline conditions or changes in environmental or ROW conditions in the vicinity of a pipeline.
- FAQ-19 clarifies that operators are expected to remain cognizant of changes along their pipeline. Over time, new HCAs may be identified as population distributions change, or new locations develop where people congregate.

- FAQ-20 clarifies that newly-identified HCAs must be incorporated into the integrity management program (including the baseline assessment plan) within one year of their identification. When new information indicates an area could meet HCA criteria, then the pipeline segment must be evaluated using either Method 1 or 2.
- FAQ-150 discusses expectations that must be met if an operator does not have HCAs on their system. An operator need not develop an integrity management program if there are no HCAs on its system. The operator must have completed an evaluation to determine that no high consequence areas exist, and this evaluation must be maintained available for inspection. An operator must have a process to periodically evaluate its pipeline to determine if new HCAs have been created. If the periodic evaluation identifies that a new HCA exists, then the operator must prepare an integrity management plan and meet all the requirements of Subpart O.
- FAQ-179 states that if an operator initially has had no HCAs and therefore no integrity management program, they will have to develop an integrity management program after discovery of a new HCA. The newly-identified HCAs must be incorporated into an operator's baseline assessment plan within one year from the date the area is identified.
- FAQ-183 clarifies that a change in HCA identification methodology does not in itself constitute a change requiring notification under §192.909(b).
- FAQ-233 clarifies how the growth of an existing HCA, which introduces new length of pipeline segment into the HCA, is to be considered. Growth of a pipeline segment already in the IM program, as a result of growth of the related HCA, does not constitute a newly-identified HCA, and no requirements of the rule applicable to newly-identified HCAs are triggered by such growth. Operators must assure, however, that the pipe newly covered under the IM program is appropriately assessed at the next scheduled assessment for the covered segment. Operators must also consider any unique issues, e.g., relative to preventive and mitigative measures decisions, that may be introduced by including the new pipe as part of the HCA.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix A.01, Bookmark A6, Protocol A.6.

A.06.a. Verify the operator's integrity management program includes documented processes for how new information that shows a pipeline segment impacts a high consequence area is identified and integrated with the integrity management program. The program is to identify and analyze changes for impacts on pipeline segments potentially affecting high consequence areas. Issues the program must consider include but are not limited to:[§192.905(c)]

i. Changes in pipeline maximum allowable operating pressure (MAOP),
ii. Pipeline modifications affecting piping diameter,
iii. Changes in the commodity transported in the pipeline,
iv. Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites,
v. Change in the use of existing buildings (e.g., hotel or house converted to nursing home),
vi. Installation of new pipeline,
vii. Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
viii. Pipeline reroutes
ix. Corrections to erroneous pipeline center line data.

A.06.a. Supplemental Guidance:

- New and changing HCAs should be identified by the operator using additional information that can be obtained about HCAs, such as local knowledge of HCAs by its field personnel, verification during ROW surveillance including aerial patrols, aerial photographs, cathodic protection surveys, maintenance, one-call data, etc. This information should be used to accurately identify all HCAs, including changes to HCAs. The operator should explain how information obtained from such routine activities is captured in its HCA identification maps or system.
    - FAQ-19 clarifies that operators must continually monitor conditions along their pipeline.

- PHMSA would expect that operators would evaluate conditions along their pipelines at least annually to determine if they have changed.
    - FAQ-20 states that over time, new HCAs may be identified, such as when population distributions change or new sites that are occupied by 20 or more persons are identified. Operators must consider such changes to determine whether new HCAs have been created.
    - FAQ-117 states that operators are expected to assure that their HCA definitions are current. PHMSA would expect that operators would evaluate conditions along their pipelines at least annually to determine if they have changed.
- Operator IM programs should have provisions for periodically re-contacting public officials to find new identified sites, as part of the routine activities to find new HCAs. The rule (as currently written) does not specify an interval for re-contacting public officials in order to routinely find new identified sites. So, it is up to the operator to establish one. Per DCC, PHMSA believes that prudent operators would make contact at least every 3 years. Inspectors should challenge the basis for IM programs that specify longer intervals (or that do not require that public officials be re-contacted periodically) and identify it as a potential issue, if sound reasoning and justification is not documented. Operators must look for "identified sites" during their normal operation and maintenance activities, but do not have to contact public officials on an annual basis after the initial contact.

Protocol Area B. Baseline Assessment Plan

- B.01 Assessment Methods
- B.02 Prioritized Schedule
- B.03 Use of Prior Assessments
- B.04 Newly Identified HCAs/Newly Installed Pipe
- B.05 Consideration of Environmental and Safety Risks
- B.06 Changes
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B.01 Assessment Methods

Verify that the operator's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment. [§192.919(b), §192.921(a), §192.921(c), and §192.921(h)]

B.01 *Supplemental Guidance:*

- The integrity assessment methods that can be used are in-line inspection, pressure testing, direct assessment or other methodologies provided in ASME B31.8S-2004, Section 6.
- Requirements that are imposed on pipeline that operates at 80% SMYS under a waiver typically require that the entire pipeline subject to the waiver be treated as an HCA and assessed using ILI.
- Some specific examples of risk factors along with their implications regarding tool selection are noted in Supplemental Guidance Appendix B.02. (This is not intended to be an exhaustive list of circumstances that indicate the use of other tools.)
- Integrity assessment may not be the appropriate action for the operator to take for certain threats. Other actions, such as prevention, may provide better integrity management results (e.g., some third party damage risks). Refer to Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage, for further guidance.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B1, Protocol B.1.

B.01.a Verify that the operator followed ASME B31.8S-2004, Section 6.2 and that the assessment method selected for each covered segment addresses all of the threats identified for the segment. More than one assessment tool may be necessary to address all applicable threats to a covered segment. [§192.919(b), §192.921(a), §192.921(c), and §192.921(h)]

B.01.a. Supplemental Guidance:

- The inspectors should verify that the integrity assessment method is based on the threats to which the segment is susceptible.
    - FAQ-217 states that assessment methods must be identified and demonstrated to be capable of addressing applicable threats before an assessment is conducted. For example, operators must ensure that inspection tools are capable for identification of deformation and longitudinally oriented wall loss defects which could result from third party mechanical damage.
- More than one method and/or tool may be required to address all the threats in a pipeline segment.

B.01.b. If internal inspection tools are selected, verify that the operator followed ASME B31.8S-2004, Section 6.2 in selecting the appropriate internal inspection tool for the covered segment. [§192.921(a)(1)]

i. Verify that the operator has evaluated the general reliability of any in-line assessment method selected by looking at factors including but not limited to: detection sensitivity; anomaly classification; sizing accuracy; location accuracy; requirements for direct examination; history of tool; ability to inspect full length and full circumference of the section; and ability to indicate the presence of multiple cause anomalies. Refer to ASME B31.8S-2004, Section 6.2.5. [§192.921(a)(1)]

B.01.b. Supplemental Guidance:

- A comprehensive ILI assessment program will typically consist of multiple tool runs designed to assess potential risks to pipeline segments. In some cases, an operator may choose to run ILI tools in combination with a hydrostatic test to identify crack problems.
- Supplemental Guidance Appendix B.03 provides discussion on ILI tool characteristics and attributes.
- Assessments conducted using only MFL metal loss tools require that all indications of mechanical damage in the pipeline segment be investigated/excavated unless they are known to have been repaired.
    - FAQ-68 states that operators must integrate relevant information on the condition of the pipeline in making decisions on excavation timing and repairs, including tool tolerances.
- A number of factors should influence the operator's ILI tool selection including tool capabilities, risk factors to be assessed, system configuration, pipeline condition, repair history, tool size, and operational issues. Refer to ASME B31.8S-2004, Section 6.2 for a discussion of the use of ILI tools for certain threats.
- "**SHOULD**" Requirement: Some of the more important issues that **should** be considered are: pipeline questionnaire; launchers and receivers; pipe cleanliness; type of fluid; flow rate, pressure, and temperature; product bypass/supplement.(Re: ASME B31.8S-2004, Section 6.2.5 (b)) [Re: Protocol L.03]
- Supplemental Guidance Appendix B.04, Table B.4-1 lists some of the factors that an operator should evaluate in order to make a proper tool selection, along with an indication of the type of tool(s) suited for each factor. This is a very generalized summary for convenient reference only.
- Inspectors should examine the operator's processes and implementation of ILI data validation and verification, the need for verification digs (including when they might not be needed).
- Inspectors should request unity plots that compare as called by the ILI tool vs. as found by field verification and action taken by the operator in response to discrepancies between as called and as found defects. (A situation has been observed where the ILI was seriously undercalling defects,

and the operator was having the vendor regarded the log. It had been over a year since the original final report and regrading was not complete. If logs require regrading, then the regrading must be complete within 180 days of the completion of the assessment (the 180-day discovery clock still applies, the operator must obtain sufficient information to discover within 180-days)).

- Does the operator feed verification results back to the ILI vendor even if regarding is not required?
- If the operator has not developed any unity plots, the inspector should inquire as to how the operator assured themselves that the ILI tool was providing valid results. Potential questions to be asked are:
    - Was the tool calibrated by the vendor prior to the tool run? Are calibration records available?
    - Did the operator have experience with this vendor and the tool that was used? What verification was performed on previous assessments?
    - Were repairs made based on the ILI assessment results? What was the as found condition versus the as called?
    - Were previous assessments made on this pipe section? How do the results compare?
    - Were previous repairs made to the pipe (sleeves)? What did the ILI tool call out at these locations?
- Operators should specify the threshold for vendor reporting of anomalies. For instance, one operator that was inspected in 2002 specified that the vendor should report all metal loss anomalies greater than 15% WT. The threshold should be appropriate to screen out insignificant or trivial anomalies, while still ensuring that significant anomalies that represent integrity threats are reported. The threshold values should include an allowance for tool tolerance.
- Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 192.933(d), are promptly identified. Important aspects of tool tolerance affect the following critical integrity management considerations:
    - Defect sizing data for determination of correct repair criteria categorization should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length should be increased by the amount of the tool tolerance). This is especially important for "borderline" anomalies.
    - Defect sizing data used as input into calculations to determine remaining strength of the pipe should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length should be increased by the amount of the tool tolerance).
- Tool tolerance should be considered in such a way as to assure pipeline integrity. This is important because a certain portion of anomalies that are called to be less than a certain repair criterion will in reality meet that repair criterion. For example, out of all the anomalies that are called to be 70% WT, a certain number of them are expected to exceed the 80% WT criterion for an immediate repair condition, based on typical standard MFL tool tolerance of 15%.
- Tool tolerances can also be applied to deformation depth and to orientation. For example, ILI vendors specify the accuracy of their tool in predicting the circumferential location of a defect. A 6% dent of the top of the pipe (between 8 and 4 o'clock) is a one year condition; whereas, a 6% dent on the bottom of the pipe (between 4 and 8 o'clock) is a monitored condition. Defects located near the 4 and 8 o'clock positions should be evaluated to see if they should be included in the more conservative repair condition.
- Refer to the following FAQs regarding ILI tools:
    - FAQ-46 states that ILI tools, pressure testing, and direct assessment are acceptable methods.
    - FAQ-48 refers to the ASME B31.8S-2004 standard for selecting tools for internal inspection.
    - FAQ-55 states that a pressure reduction is not an assessment method.

B.01.c. If a pressure test is specified, verify that the test is required to be conducted in accordance with Part 192, Subpart J requirements. Verify that the operator followed ASME B31.8S-2004, Section 6.3 in selecting the pressure test as the appropriate assessment method. [§192.921(a)(2)]

B.01.c. Supplemental Guidance:

- An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939 (refer to Protocol F).
- Processes, plans, and procedures should be reviewed to the extent necessary to determine that the pressure test did/will conform to Subpart J.
- Verify that the test procedure contains appropriate test acceptance criteria. Supplemental Guidance Appendix B.06 provides more detailed information on the type of criteria the inspector should expect to see in the test plan as well as other important information regarding hydrostatic testing.
- The operator's IMP should require metallurgical examination of the failed material if test failures occur. This examination can provide more information about the material condition of the pipe.
- Refer to the following FAQs regarding pressure tests:
    - FAQ-49 refers to Subpart J as the acceptable pressure test.
    - FAQ-53 states that any pressure test that meets or exceeds the requirements of Subpart J is acceptable.
    - FAQ-109 states that where the language in the rule and ASME B31.8S-2004 conflict, the rule takes precedence.
    - FAQ-141 states that use of a spike test alone would constitute "other technology."
    - FAQ-219 states that the use of a pressure test is sufficient to reveal manufacturing and construction defects.
    - FAQ-236 states that operators may use straight-line interpolation to determine acceptable intervals between the 5, 10, 15, and 20 year intervals listed in ASME B31.8S Table 3. In no case must operators reassess more frequently than once every seven years unless such frequent reassessments are determined necessary by risk assessment.

B.01.d. If the operator specifies the use of "other technology," verify that notification to PHMSA is required in accordance with Part 192.949, 180 days before conducting the assessment. Also, verify that notification to a State or local pipeline safety authority is required 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. [§192.921(a)(4)]

B.01.d. Supplemental Guidance:

- If the operator chooses to use other technology review copies of the operator's notification, along with the scheduled (or actual) assessment date shown in the BAP to verify that the 180 day requirement was met.
- If the BAP schedule specifies using other technology in the future, and a notification has not yet been submitted to PHMSA, verify that the BAP schedule or IM Program specifies that the required notification be submitted to PHMSA at least 180 days before conducting the assessment. In this case, make a note in the inspection documentation so PHMSA can track the expected notification and follow up in future inspections if not received.
- Verify that the other technology is capable of assessing the applicable threat.
- Refer to the Guided Wave UT Target Items for Go-No Go Procedures provide in the IMDB File Library. (Reference: Checklist)
- Refer to the following FAQs:
    - FAQ-55 states that a pressure reduction is not an assessment method.
    - FAQ-198 clarifies the use of guided wave UT technology and its potential consideration as "other technology."
    - FAQ-204 clarifies that close interval survey/overline survey does not qualify as "other technology."

- FAQ-235 notes that if guided wave technology is being used as a tool to examine the predicted locations to determine if corrosion exists, then it is being used in a manner consistent with the ICDA process and would not be considered "other technology". If, on the other hand, the intent is to use guided wave technology in some other manner to assess internal corrosion (e.g., not first analyzing the pipeline to determine likely locations for internal corrosion), then its use would be different from the normal ICDA process and it would be considered "other technology".

B.01.e. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies 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 verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion anomalies. [§192.917(e)(4)]

B.01.e. Supplemental Guidance:

- All pipelines are considered to contain manufacturing and construction defects since there is no practical way to guarantee a defect-free pipe. Refer to Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects, for further guidance.
- A successful Subpart J pressure test is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at operating pressures less than or equal to MAOP, as of the date of the pressure test. Refer to the following FAQs:
  - FAQ-219 states that the use of a pressure test is sufficient to reveal manufacturing and construction defects.
  - FAQ-220 states that assessments may be required if operating conditions change.
  - FAQ-141 suggests that operators might consider supplementing a Subpart J hydrostatic pressure test with a spike test.
- Pipelines that have experienced failures due to seam defects or other manufacturing and construction defects since its last Subpart J pressure test are considered to be susceptible to these threats.
- If there are any low-frequency ERW (LFERW) or lap-welded (LW) pipe segments susceptible to longitudinal seam failure included in the operator's BAP, verify that those segments are uniquely identified. A sampling of older pipe that is not designated as LFERW or LW should be reviewed and verified relative to its type of construction to verify that the operator has correctly identified all such pipe. This is especially important if the operator has not identified any of its pipe as LFERW or LW pipe.
- Refer to Supplemental Guidance Appendix B.05 for additional discussion on ERW piping.
- Refer to the following reports for information regarding the potential for anomalies from manufacturing and construction related practices.
  - Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., October 2004 (Reference: VINTAGE)
  - Final Report No. 05-12R, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, John F. Kiefner, April 26, 2007 (Reference: 05-12R)
- FAQ-231 provides discussion on the five year time period. The "preceding five years" referred to is the same five years preceding HCA identification.

B.01.f. 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, verify that the operator documents an acceptable justification for the use of an alternative assessment method that will address the identified threats to the covered segment. [§192.921(h)]

B.01.f. Supplemental Guidance:

- The assessment method selected should address the threat identified. Use the guidance in ASME B31.8S-2004, Section 6 to verify that the assessment method is appropriate.
- Consider information in Advisory Bulletin ADB-99-02, Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems (Reference: ADB-9902), which informs operators of the potential vulnerability of older plastic gas pipelines to brittle-like cracking.

B.02 Prioritized Schedule

Verify that the BAP contains a schedule for completing the assessment activities for all covered segments; and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule. [§192.917(c), §192.919(c) and §192.921]

B.02 *Supplemental Guidance:*

- Separate operating companies may have separate BAPs.
  - FAQ-38 states that operators with multiple operating companies may have one BAP for each operating company or separate legal entity.
- 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.
- The baseline assessment plan and framework must have been completed by December 14, 2004. Refer to the following FAQs:
  - FAQ-72 states that BAP and the framework both must be prepared by December 17, 2004.
  - FAQ-73 states that PHMSA will not develop a template for BAPs or IM program frameworks.
  - FAQ-78 states that PHMSA expects HCA segments to be risk ranked using a process that is consistently and uniformly applied across all of its covered segments.
  - FAQ-140 states that PHMSA expects the level of detail in the framework to vary depending on the level of maturity of each program element.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B2, Protocol B.2.

B.02.a. Verify that the BAP schedule includes all covered segments not already assessed. [§192.921(a)]

B.02.a. Supplemental Guidance:

- Each segment of pipeline that could affect an HCA must have a documented date for when its baseline assessment was or will be performed.
  - FAQ-9 states that the rule only applies to transmission lines.
- Idle lines that affect HCAs should be listed although if the line is inactive (no hazardous gas content) its baseline assessment may be postponed.
  - FAQ-7 states that operators must meet all of the rule requirements for their in-service pipe (i.e., that contains gas).
- Verify that the operator's schedule provides dates for each segment scheduled for assessment in the near term, and does not consolidate the segments into large groups for scheduling purposes. Segments scheduled in out-years may be listed in the BAP by quarters.
  - FAQ-39 states that PHMSA expects to see a viable, active planning and scheduling process in the BAP with the degree of specificity dependent on how far in the future the assessments are planned.
- 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 states that the date an assessment is considered complete is the date on which final field activities related to that assessment are complete (not including repairs).
- Refer to the following additional FAQs regarding the BAP:
    - FAQ-6 states that certain sections of the rule apply to pipelines as defined in 192.3. This includes compressors, valves, metering stations, etc.
    - FAQ-10 states that the regulatory deadlines for assessments continue to apply when ownership of a pipeline is transferred.
    - FAQ-36 states that the 50% requirement applies to all pipeline covered under the rule, including interstate and intrastate, and thus both categories should be included in a single BAP.

B.02.b. Verify that the BAP schedule prioritizes the covered segments based on potential threats and applicable risk analysis, and that the risk ranking is appropriate. [§192.917(c) and §192.921(b)]

B.02.b. Supplemental Guidance:

- The operator must properly account for all risk factors that reflect the risk conditions on the pipeline segment. The BAP should be reviewed to verify that all of the risk factors associated with the segments were appropriately considered. Refer to the following FAQs:
    - FAQ-28 states that the risk posed by each pipeline segment must be considered in scheduling baseline assessments.
    - FAQ-125 which states that the risk ranking should be by covered segment, not piggable segments.
- Review the risk analysis results to determine if the operator did not consider any applicable risk factors in establishing the schedule priority for baseline assessment. This review may have been accomplished as part of Protocol C.
    - FAQ-78 states that PHMSA expects HCA segments to be risk ranked using a process that is consistently and uniformly applied across all of its covered segments.
- Verify that business and economic factors do not inappropriately influence the prioritizations of covered segments in the BAP.
    - FAQ-102 states that the BAP ranking must be based on risk and not be skewed by non-risk factors.
- Refer to the following FAQs regarding BAP schedules:
    - FAQ-33 states that operators should count only covered segment miles in meeting the 50% requirement.
    - FAQ-35 states that operators must concentrate the highest risk pipe in the top 50% but some segments not among the highest risk pipe may be scheduled in the top 50%.
    - FAQ-39 states that PHMSA expects to see a viable, active planning and scheduling process in the BAP with the degree of specificity dependent on how far in the future the assessments are planned.

B.02.c. Verify that covered segments meeting the following conditions are prioritized as high-risk segments.

i. 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. [§192.917(e)(4)]

ii. 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. [§192.917(e)(3)]

B.02.c. Supplemental Guidance:

- The inspector should review the risk analysis results to determine if any of these conditions were identified as a concern in any covered segments. Covered segments that have these risk concerns should be identified as high risk and scheduled for assessment early in the BAP. Refer to Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects for more guidance. Refer to the following FAQs:
    - FAQ-219 states that the use of a pressure test is sufficient to reveal manufacturing and construction defects.
    - FAQ-220 states that assessments may be required if operating conditions change.
- The inspector should use his/her judgment as to whether the operator placed sufficient priority on segments that contain LFERW/LW pipe or manufacturing/construction defects relative to other high-risk segments.
- If a covered pipeline segment contains LFERW or LW pipe, or other pipe that satisfies the conditions specified in Supplemental Guidance Appendix B.05, Bookmark B51, Section B.5.01, Background Discussion for LFERW or LW Pipe, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies.
- Refer to the following FAQs regarding high risk segments:
    - FAQ-169 states that PHMSA expects the "high risk" segments to be given special consideration in developing an assessment schedule.
    - FAQ-35 states that operators must concentrate the highest risk pipe in the top 50% but some segments not among the highest risk pipe may be scheduled in the top 50%.
    - FAQ-221 states that, relative to 192.917(e)(3)(i), any pressure increase, regardless of amount, will require that the segment to be prioritized as high risk.

B.02.d. Verify that the BAP schedule requires 50% of the covered segments, beginning with the highest risk segments, to be assessed by December 17, 2007; and that baseline assessments shall be completed for all covered segments by December 17, 2012. [§192.921(d)]

B.02.d. Supplemental Guidance:

- Verify that the schedule complies with the progress requirements.
- The progress requirement is not intended to mandate that each and every one of the top 50% of segments in terms of risk must be assessed in sequential order. Nor does it mean that all of the top 50% must be assessed by the compliance deadline. The schedule is allowed to accommodate necessary business factors in a way that makes sense.
- Review the operator's tracking mechanism for ensuring that the 50% progress requirement is met.
- Verify that the schedule is integrated into the operator's management systems used to actually budget and schedule work.
- PHMSA recognizes that all of the mileage in a segment may not be completed by a particular integrity assessment. For instance, a segment may be non-piggable and is assessed by ECDA. However, if the segment has a casing, that casing may not be assessed until a later time by other assessment techniques (e.g., guided wave). The operator would be allowed to credit the mileage of that portion of the segment that had a completed and valid ECDA. This position is discussed further in the AGA letter to PHMSA regarding gas transmission pipelines in casings dated April 18, 2007 (Reference: Casing1) and the PHMSA response to AGA dated October 25, 2007 (Reference: Casing2).
- Refer to the following FAQs regarding the 50% schedule:
    - FAQ-26 states that baseline assessments must be complete by December 17, 2012; and 50% of HCA mileage completed by December 17, 2007.
    - FAQ-33 states that operators should count only covered segment miles in meeting the 50% requirement.

- FAQ-35 states that operators must concentrate the highest risk pipe in the top 50% but some segments not among the highest risk pipe may be scheduled in the top 50%.
- FAQ-36 states that the 50% requirement applies to all pipeline covered under the rule, including interstate and intrastate, and thus both categories should be included in a single BAP.
- FAQ-169 states that PHMSA expects the "high risk" segments to be given special consideration in developing an assessment schedule.

B.02.e. Review the operator's implementation progress to date and verify that: [§192.921]

i. Assessments scheduled for completion by the date of the inspection were in fact completed.
ii. Assessment methods used for completed assessments were as described in the plan.
iii. The date assessment field activities were completed is recorded [so the operator understands the time frame allowable for compliance with the provisions of §192.933].

B.02.e. Supplemental Guidance:

- Review the BAP schedule and verify that those assessments scheduled to be completed at the time of the inspection are in fact completed.
- Verify that assessment documentation is available for completed assessments.
- Verify that the assessment completion date documented by the operator is correct.
  - FAQ-34 states that the date an assessment is considered complete is the date on which final field activities related to that assessment are complete (not including repairs).
- Verify that baseline assessment activities began by June 7, 2004. Refer to Advisory Bulletin ADB-03-07, Guidance on When the Baseline Integrity Assessment Begins, November 17, 2003 (Reference: ADB-0307) for guidance regarding what activities are considered to be baseline assessment activities.

B.03 Use of Prior Assessments

If prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of §192.921(a) and that remedial actions have been carried out to address conditions listed in §192.933. Prior assessments are those that were completed prior to December 17, 2002. [§192.921(e)]

B.03 *Supplemental Guidance:*

- There is no specified limit regarding how far back in time prior assessments may be considered as baseline assessments.
- An assessment performed between December 17, 2002 and the effective date of the rule (February 14, 2004) cannot be considered a prior assessment. However, it can be considered a regular baseline assessment if the operator so designates. If the operator designates an assessment completed between December 17, 2002 and February 14, 2004, as a baseline assessment then the operator is required to repair anomalies per the rule requirements with the rule required repair criteria coming into force on the effective date of the rule, or on the date the operator declares the assessment to be a baseline assessment, whichever is later. If the operator is not going to consider the assessment a baseline assessment then the rule repair criteria do not apply. Note that anomalies identified in any assessment performed after the effective date of the rule must be repaired per the rule whether or not the operator takes credit for the assessment.
- Operators may take credit for a prior assessment that only addresses one threat provided other threats not addressed by the prior assessment are addressed by a baseline assessment.
- Refer to the following FAQs regarding the use of prior assessments:
  - FAQ-161 states that prior assessments can be relied upon to meet the requirement that operators begin assessment activities by June 17, 2004.

  - FAQ-27 states that assessments conducted before December 17, 2003, can be used as baseline assessments provided they meet the criteria established by the rule.
  - FAQ-29 states that prior assessments can be counted toward meeting the 50% requirement.
  - FAQ-152 states that prior assessments must address all applicable threats.
  - FAQ-65 states that a prior assessment is only candidate for use as a baseline assessment until all anomalies requiring repair under §192.933 are repaired.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B3, Protocol B.3.

B.03.a. Verify that threats to these pipeline sections were identified as required under §192.919(a).

B.03.a. Supplemental Guidance:

- For older prior assessments, the operator should provide more detailed and specific justification for using the prior assessment.
- Review the risk analysis results for the segments in question. Ensure that segments being credited with prior assessments were not omitted from the risk analysis process.
- Verify that the operator took reasonable steps to validate the quality, accuracy, and applicability of older data.

B.03.b. Verify that the methods used for these prior assessments were appropriate for the threats per ANSI B31.8S-2004 as required under §192.919(b) and §192.919(d).

B.03.b. Supplemental Guidance:

- Identify the threat(s) that the operator is intending to address by any prior assessment being credited as a baseline assessment and verify that the prior assessment method addresses these threat(s). Prior assessments may be credited for particular threats. However, if other threats exists for that segment and those threats require a different assessment method, then that assessment method will still need to be performed on the segment as part of the baseline assessment.
- Refer to the supplemental guidance under Protocol B.01 for guidance regarding selection of the appropriate assessment method.

B.03.c. Verify that anomalies satisfying the requirements of §192.933 were repaired.

B.03.c. Supplemental Guidance:

- Verify that older data is comprehensive enough to determine if indications meet repair criteria.
- The prior assessment data must support the performance of remaining strength calculations and be accurate enough to distinguish immediate repair and other defects in accordance with §192.933.
- Refer to Protocol E for guidance regarding remediation criteria under this rule.

B.04 New HCAs/Newly Installed Pipe

Verify that the operator updates the baseline assessment plan for new HCAs and newly installed pipe. [§192.905(c), §192.921(f), §192.921(g)]

B.04 *Supplemental Guidance:*

- 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 plus be credited as newly installed pipe that does not require re-assessment for another 10 years.
- Refer to the following FAQs:
    - FAQ-30 states that changes to a baseline assessment schedule do not require a waiver.
    - FAQ-31 states that only changes to the program that substantially affect the program's implementation or may significantly modify the program or schedule require notifications to PHMSA.
    - FAQ-124 states that any HCAs on the newly installed pipe must be identified and included in the baseline assessment plan within one year.
    - FAQ-161 states that prior assessments can be relied upon to meet the requirement that an operator begin assessment activities by June 17, 2004.
    - FAQ-233 clarifies that the growth of a pipeline segment already in the IM program, as a result of growth of the related HCA, does not constitute a newly-identified HCA, and no requirements of the rule applicable to newly-identified HCAs are triggered by such growth.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B4, Protocol B.4.

B.04.a. If new HCAs have been identified or new pipe has been installed that is covered by this subpart, verify that applicable segment(s) have been incorporated into the operator's baseline assessment plan within one year from the date the area or pipe is identified and assessments have been appropriately scheduled and/or completed. [§192.905(c)]

B.04.a. Supplemental Guidance:

- Evaluate the program procedures and processes to determine if requirements exist to adequately identify and evaluate newly identified high consequence areas in which the operator's pipelines are located (refer to Protocol A.06).
- Verify that the operator's IM Program requires that the continual process of performing information analysis includes steps to promptly identify new HCAs and incorporate the new HCA affecting segments into the BAP and the integrity assessment process.
- Using the results of the review of the HCA identification analysis, verify that the operator's BAP has been properly updated to reflect the impact of newly-identified HCAs within one year of identification.
- Pipe is considered either active or abandoned. All idle pipe that could affect an HCA is subject to the requirements of §192.921 and must be included in the BAP.
    - FAQ-7 states that in-service pipe that contains gas is covered by the rule.
- 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.
- Acquisition of a pipeline by an operator includes accepting all of the obligations attendant upon that pipeline as a result of regulatory requirements. Refer to the following FAQs:
    - FAQ-10 states that regulatory deadlines for assessments continue to apply after a pipeline has transferred ownership.
    - FAQ-11 states that compliance responsibilities will have to be determined on a case-by-case basis and is contingent on the terms of contracts, operating agreements, and other relevant correspondence between involved parties.
- 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. Refer to the following FAQs:
    - FAQ-25 states that a BAP must be changed whenever there are changes to the pipelines in HCAs.

- FAQ-110 states that if a new covered segment is identified it has a 10 year assessment schedule and reprioritizing the BAP is not required.

B.04.b. For new HCAs, verify that the operator completes a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified. [§192.921(f)]

B.04.b. Supplemental Guidance:

- Verify that the operator's IM Program requires that a baseline assessment of new HCAs be completed within 10 years from the date the area is identified.
- Changes to existing HCA boundaries should not be treated like new HCAs. This requirement applies to any geographical area that was previously not contained within or adjacent to an HCA boundary, but that now is (or should be) contained within an HCA boundary.
  - FAQ-110 states that if a new covered segment is identified it has a 10 year assessment schedule and reprioritizing the BAP is not required.
  - FAQ-233 clarifies how the growth of an existing HCA, which introduces new length of pipeline segment into the HCA, is to be considered. Growth of a pipeline segment already in the IM program, as a result of growth of the related HCA, does not constitute a newly-identified HCA, and no requirements of the rule applicable to newly-identified HCAs are triggered by such growth. Operators must assure, however, that the pipe newly covered under the IM program is appropriately assessed at the next scheduled assessment for the covered segment. Operators must also consider any unique issues, e.g., relative to preventive and mitigative measures decisions, that may be introduced by including the new pipe as part of the HCA.

B.04.c. For newly installed pipe that is covered by this subpart and impacts an HCA, verify that the operator completes a baseline assessment within ten (10) years from the date the pipe is installed. [§192.921(g)]

B.04.c. Supplemental Guidance:

- Verify that the operator's IM Program requires that a baseline assessment of a newly-installed segment of pipe covered by this subpart be completed within 10 years from the date the pipe is installed.
  - FAQ-110 states that if a new covered segment is identified it has a 10 year assessment schedule and reprioritizing the BAP is not required.
  - FAQ-237 clarifies that any pipe installed after 2/14/04 (the effective date of the rule)but before 12/17/04 (the date by which integrity management programs must be in place) is considered to be "newly installed" and its deadline for completing the baseline assessment is 10 years after installation.
- An operator may take credit for an initial pressure test in accordance with §192.921(a)(2), to satisfy the requirement for a baseline assessment.

B.04.d. Verify that threats to these pipeline sections were identified as required under §192.919(a). [§192.921(b)]

B.04.d. Supplemental Guidance:

- Refer to Protocol C for guidance.

B.04.e. Verify that the assessment methods used were appropriate for the threats per ASME B31.8S-2004 as required under §192.919(b) and 192.919(d).

B.04.e. Supplemental Guidance:

- Refer to Protocol B.01 above for guidance.
- FAQ-7 states that in-service pipe that contains gas is covered by the rule.

B.05 Consideration of Environmental and Safety Risks

Verify that the operator addresses requirements for conducting the integrity assessments (baseline and reassessment) in a manner that minimizes environmental and safety risks. [§192.919(e) and §192.911(o)]

B.05 *Supplemental Guidance:*

- Operators may use existing operating/safety procedures provided they address the issues associated with environmental and safety risks.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B5, Protocol B.5.
- This protocol question pertains to both baseline assessments and reassessments evaluated in accordance with Protocol F.

B.05.a. Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of gas) during assessments. [§192.919(e) and §192.911(o)]

B.05.a. Supplemental Guidance:

- Review the operator's procedure to ensure that appropriate safety measures are included.
- Considerations to be addressed in procedures may include:
    - minimizing byproducts from the assessment,
    - special monitoring,
    - keeping personnel at safe distances when pressurizing pipelines
    - controlling ignition sources
    - line de-pressurization, and
    - use of protective clothing.

B.06 Changes

Verify that the operator keeps the BAP up-to-date with respect to newly arising information. Also refer to Protocol K. [§192.911(k) and ASME B31.8S-2004, Section 11]

B.06 *Supplemental Guidance:*

- Maintaining the BAP up-to-date is vital to ensuring that the highest risk segments are assessed early in the process and are assessed with the best assessment method.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix B.01, Bookmark B6, Protocol B.6.

B.06.a. Verify that the operator's process has requirements to keep the BAP up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method. [§192.911(k) & ASME B31.8S-2004, Section 11]

B.06.a. Supplemental Guidance:

- The operator's program and procedures must require that the Baseline Assessment Plan be revised and documented for any reason that affects the segments that could affect HCAs. These include such things as:
    - Revisions to existing HCA boundaries,
    - New or modified pipeline installations,
    - Purchase or acquisition of pipeline systems,
    - Divestiture of pipeline systems,
    - Revisions to the impact analysis
    - Revisions to the risk analysis or integrated information analysis,
    - Results of completed assessments, and
    - Any other change that could affect the assessment method or schedule.
- If changes have been noted during the inspection of Segment Identification, Risk Analysis, or other program elements that affect the BAP, verify that the changes have been properly incorporated into the BAP.
- Verify that the BAP is consistent with the latest revision of the other program element documentation. Changes to these other program elements can affect tool selection, assessment schedule, segments that require assessment, and segment prioritization.
- Refer to the following FAQs regarding changes to BAPs:
    - FAQ-25 states that a BAP must be modified whenever there are changes to the pipeline in HCAs.
    - FAQ-31 states that only changes that substantially affect the program's implementation or may significantly modify the program or schedule require PHMSA notification.
    - FAQ-32 states that operators must maintain for the useful life of the pipeline documents to support decisions, analysis, processes developed, etc., including revisions to the BAP.

B.06.b. Verify that required BAP changes have been made and that for all changes, the following are documented: [ASME B31.8S-2004, Section 11(a)]

i. Reason for change
ii. Authority for approving change
iii. Analysis of implications
iv. Communication of change to affected parties

B.06.b. Supplemental Guidance:

- If an operator's BAP is still the original issuance at the time of the IM inspection, the inspection of these protocols will be limited to verifying that the operator's IM program has the necessary requirements to control and document future revisions to the BAP.
- The following are some examples of potential BAP changes to review for compliance with this codified requirement:
    - Removal of Segments
    - Changes to Assessment Schedule Dates
    - Removal of Segments from the BAP after its Assessment
    - Assessment Conducted (or Planned) Using Different Methods than Documented in the BAP
- Deletions and boundary reductions (due to segment endpoint changes) should be carefully reviewed to verify that they are appropriate and adequately justified.
- Refer to the following FAQs:
    - FAQ-30 states that waivers are not required for changes to the BAP.
    - FAQ-31 states that only changes that substantially affect the program's implementation or may significantly modify the program or schedule require PHMSA notification.

- FAQ-32 states that operators must maintain for the useful life of the pipeline documents to support decisions, analysis, processes developed, etc., including revisions to the BAP.
- FAQ-97 describes the notifications required by the rule.
- FAQ-98 states that notifications regarding substantial changes to the program must be submitted to PHMSA no less than 30 days after the change is made.
- FAQ-111 states that changes requiring PHMSA notification would include significant revisions to the BAP such as significant delays in segment assessments or changes that affect the overall manner in which an operator is conducting its IM program.

Protocol Area C. Identify Threats, Data Integration, and Risk Assessment

- C.01 Threat Identification
- C.02 Data Gathering and Integration
- C.03 Risk Assessment
- C.04 Validation of the Risk Assessment
- C.05 Plastic Transmission Pipeline
- Table of Contents

C.01 Threat Identification

Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment. [§192.917(a)]

C.01 *Supplemental Guidance:*

- This Protocol represents requirements for operator identification and evaluation of threats to the integrity of pipeline segments.
- Threats are identified in order to determine what mechanisms can cause failure of each segment so that appropriate assessment methods are applied to the segments and effective preventive and mitigative measures can be defined for the segments.
- Threats are evaluated in order to provide input to segment risk assessment, which is used to set segment integrity assessment priorities and evaluate the benefits of preventive and mitigative activities.
- Refer to Supplemental Guidance Appendix C.01, Bookmark C1, Protocol Guidance for Identification of Threats, Data Integration, and Risk Assessment, for additional guidance on Protocol C.01.
- Note that manufacturing and construction (M&C) defects may be considered as threats depending on their stability. Stability of threats is discussed in the technical report, Final Report No. 05-12, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, John F. Kiefner, April 26, 2007 (Reference: 05-12R). This report also addressed cyclic fatigue since that is a major factor in causing manufacturing and construction defects to become unstable. The "M" and "C" flowcharts contained in Appendix B of this report serve as a valuable tool in the determination of manufacturing and construction defect stability. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects, addresses the stability of M&C threats and the conditions that require either further monitoring or assessment (table shown below for convenience).

Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects

Characteristics	Test History	Conditions	Stability	Assessment Required
LFERW Pipe or Joint Factor < 1 (lap-weld, hammer weld, butt weld)	No Subpart J Test	• MAOP increase, **OR** • 5-yr historical MOP exceeded, **OR** • subject to cyclic fatigue or other interacting threats, **OR** • similar pipe in the system has experienced seam failure	Non-stable	• Must be prioritized as "high risk" • Perform integrity assessments capable of assessing seam integrity
		• No MAOP increase, **AND** • 5-yr historical MOP not exceeded, **AND** • not subject to cyclic fatigue or other interacting threats, **AND** • no failure history of similar pipe	Stable	• Integrity assessments capable of assessing seam integrity ***not*** required • Monitor for MAOP increases, pressure increases exceeding 5-yr historical conditions, cyclic fatigue, seam failures elsewhere in the system, or other interacting threats
	Subpart J Test	• Subject to cyclic fatigue or other interacting threats, **OR** • Similar pipe in the system has experienced seam failure	Non-stable	• Must be prioritized as "high risk" • Perform integrity assessments capable of assessing seam integrity
		• Not subject to cyclic fatigue or other interacting threats, **AND** • No similar pipe in the system has experienced seam failure	Stable	• Integrity assessments capable of assessing seam integrity ***not*** required • Monitor for MAOP increases or pressure excursions in excess of MAOP
Cast Iron Pipe, Steel Pipe > 50 Years, Mechanically Coupled Pipe, Acetylene Girth Weld Pipe	NA - requirements from ASME B31.8S, App. A.4, §4.3 & 4.4	• Pipe experiences low temperatures, **OR** • Pipe is subject to movement, **OR** • Pipe is subject to removal of supporting backfill	NA – requirements from ASME B31.8S, App. A.4, §4.3 & 4.4	• Examination of terrain • Monitor for movement with appropriate intervention • For cast iron pipe, assessment must specifically include evaluation of susceptibility to land movement or removal of support
	No Subpart J Test	• MAOP increase, **OR** • 5-yr historical MOP exceeded, **OR** • subject to cyclic fatigue or other interacting threats, **OR** • similar pipe in the system has experienced seam failure	Non-stable	• Must be prioritized as "high risk" • Perform integrity assessments capable of assessing seam integrity
		• No MAOP increase, **AND** • 5-yr historical MOP not exceeded, **AND** • not subject to cyclic fatigue or other interacting threats, **AND** • no failure history of similar pipe	Stable	• Integrity assessments capable of assessing seam integrity ***not*** required • Monitor for MAOP increases, pressure increases exceeding 5-yr historical conditions, cyclic fatigue, seam failures elsewhere in the system, or other interacting threats
	Subpart J Test	• Subject to cyclic fatigue or other interacting threats, **OR** • Similar pipe in the system has experienced seam failure	Non-stable	• Must be prioritized as "high risk" • Perform integrity assessments capable of assessing seam integrity
		• Not subject to cyclic fatigue or other interacting threats, **AND** • No similar pipe in the system has experienced seam failure	Stable	• Integrity assessments capable of assessing seam integrity ***not*** required • Monitor for MAOP increases or pressure excursions in excess of MAOP

C.01.a. If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]

i. external corrosion,
ii. internal corrosion,
iii. stress corrosion cracking;
iv. manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3];
v. welding- or fabrication-related defects,
vi. equipment failures;
vii. third party/mechanical damage [§192.917(e)(1)],
viii. incorrect operations (including human error),
ix. weather-related and outside force damage,
x. cyclic fatigue or other loading condition [§192.917(e)(2)],
xi. all other potential threats

C.01.a. Supplemental Guidance:

- The rule specifies nine threat categories that need to be considered (i through ix above), representing the major causes of pipeline failures.
- Operators need a documented basis for their judgment regarding the applicability of each threat category to each covered segment. If the operator eliminates any category as a threat for a segment, then this decision needs to be justified.
- In general, a threat should be included for a segment if the operator's failure history includes failures due to the threat on the segment or similar segments (both covered segments and other segments in the operator's system). Also, segments with characteristics indicating a known vulnerability to a threat should include this threat (unless the operator is able to establish that action has been taken to reduce the threat to a negligible level on the segment). See Supplemental Guidance Appendix B.02 for segment characteristics associated with specific threats.
- PHMSA has established criteria for determining whether manufacturing-, welding-, and fabrication defects on segments may be considered "stable" (i.e., defects exist but are not a threat to pipeline integrity because operating conditions are unlikely to lead to the defect deteriorating to failure). Refer to the following reports and FAQs:
    - Final Report No. 05-12, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, John F. Kiefner, April 26, 2007. (Reference: 05-12R) The "M" and "C" Charts in Appendix B of this document (see p. 47) provide valuable inspection tools to help ascertain if such defects should be regarded as "stable" or not.
    - Key to the determination of whether manufacturing and construction defects can remain stable and not threaten segment integrity is whether other threats interact with these defects. See Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects, for a discussion of potential interacting threats for manufacturing and construction defects.
    - FAQ-219 states that a successful Subpart J pressure test is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at operating pressures less than or equal to MAOP, as of the date of the pressure test.
    - FAQ-220 clarifies that the rule requires that pipeline segments be prioritized as high risk, and appropriately scheduled for an assessment, if the operating conditions change significantly.
    - FAQ-221 clarifies that the rule specifies that any pressure increase, regardless of amount, will require that the segment be prioritized as high risk for integrity assessment.
    - FAQ-231 provides discussion on the five year time period that must be considered to establish a reference pressure for stability of maintenance and construction defects. The "preceding five years" referred to is the same five years preceding HCA identification.

- TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 (Reference: TTO-05), documents a review focused on evaluation of longitudinal seams on LF-ERW pipe and lap-welded pipe, particularly that manufactured before 1970, as well as DC-ERW pipe and EFW pipe.
- FAQ-218 states that, in general, operators are not required to conduct integrity assessments to address mechanical damage. However, if the operator's information integration indicates residual third party or mechanical damage (i.e., no immediate failure), then indicated conditions must be excavated or a suitable integrity assessment must be conducted. See Supplementary Guidance Appendix B.07, White Paper, Assessing for Third Party Damage, for further guidance.
- FAQ-91 states that 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 could affect an HCA.
- Potential failures from "external events" (e.g., weather and other non-human causes of pipeline mechanical damage) should be considered based on the hazards existing for each segment location.
    - FAQ-83 states that as part of the information and risk analysis required by §192.917 (b) and (c), an operator is to consider all information that can affect the likelihood and consequences of pipeline failure.
- Cyclic fatigue is of particular concern as a threat that interacts with SCC and with manufacturing and construction (especially weld) defects in segments. See Protocol C.01.c, as well as the discussion on interacting threats in Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects. During the peak demand winter seasons, some operators, especially distribution companies, commonly increase operating pressure during the day (line packing) to help meet demand during the coldest nighttime hours. Inspectors should determine if operators consider the impact of these operational practices when evaluating cyclic fatigue. Note that system-wide or generic studies of cyclic fatigue may be used by an operator as long as the operator documents the reason why the study is applicable to the segment-specific conditions.
- The operator's threat identification needs to be proactive and investigative in nature. In addition to consideration of the failure categories listed in i-x, operators need to address all other threats that stem from unique segment characteristics.
- The list of 21 threats in ASME B31.8S-2004, Section 2.2, is not intended to be an exhaustive list of potential threats that must be considered. It is incumbent on the operator to identify and evaluate any threat to the integrity of the pipeline.
- Even though ASME B31.8S-2004 states that operators need only evaluate the nine threat categories (and not all 21 specific threats listed under each of these categories), in practice all 21 of these threats are potentially applicable to any pipeline. Evaluations must at least state why the operator chose to not evaluate any given threat listed in ASME B31.8S-2004, Section 2.2.

C.01.b. If the operator is following the performance-based approach, verify that all 21 of the threats associated with the first nine failure categories listed above have been considered. [§192.917(a) and ASME B31.8S-2004, Section 2.2]

C.01.b. Supplemental Guidance:

- For performance based programs, each threat analysis must evaluate all 21 specific threats listed in ASME B31.8S-2004, Section 2.2.
- Even if an operator concludes that a particular threat is not applicable to its pipeline, the threat evaluation must be documented and the basis for drawing such conclusions must be documented.

C.01.c. Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME B31.8S-2004, Section 2.2].

C.01.c. Supplemental Guidance:

- Note that interaction of other threats with manufacturing and construction defects is discussed in the technical report, Final Report No. 05-12, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, John F. Kiefner, April 26, 2007 (Reference: 05-12R). This report addressed threat interaction since that is a major factor in causing manufacturing and construction defects to become unstable. The "M" and "C" flowcharts contained in Appendix B of this report serve as a valuable tool in the determination of manufacturing and construction defect stability.
- See Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects, for a partial list of interacting threats that should be considered by operators. This analysis is particularly important if operators have declared threats in the categories under Protocol C.01.b to be "stable" or "time-independent" and hence not of concern for a segment.
- Additional threats are mentioned qualitatively in ASME B31.8S-2004 (e.g., cyclic loading) and others are sub-sets of listed threats but not listed explicitly (e.g., laminations are a type of defect generally referred to as "defective pipe.") Examples of additional threats that may need to be considered include:
    - Cyclic Fatigue
    - Railroad Fatigue
    - Hard spots
    - Laminations
    - Puddle weld
    - Hook crack
    - MIC
    - Selective Seam Corrosion
- Also of extreme importance is that the evaluation MUST analyze the interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time). This is a mandatory requirement clearly spelled out in ASME B31.8S-2004, Section 2.2. This is particularly important when considering manufacturing and construction threats as well as pipe seam threats. These threats may often be treated by operators as "stable" for which no integrity assessment is needed. However, other interacting threats could result in these otherwise stable defects becoming an integrity threat that must be assessed. Refer to Supplemental Guidance Appendix B.08, White Paper, Manufacturing and Construction Defects, for a more detailed discussion of this aspect of the rule.

C.01.d. Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment. [ASME B31.8S-2004, Section 5.10]

C.01.d. Supplemental Guidance:

- Operators may not eliminate any threat for a segment without an adequate basis for doing so. This basis must consider pipeline failure history, design, manufacturing, construction, operation, and maintenance. The criteria that are applied must be documented in the operator's IM program.
- For a prescriptive program, the criteria for assessment of threats are found in ASME B31.8S-2004, Appendix A.
- For a performance based program, the criteria for assessment of threats is given in ASME B31.8S-2004, Section 5.10.
- It is inadequate for an operator to conclude that a pipeline is not subject to any particular threat or threats, based solely on the fact that it has not experienced a pipeline failure that has been attributed to the threat(s).
- PHMSA expects some operators to make efforts to exclude some important threats including internal corrosion and stress corrosion cracking.
- INTERNAL CORROSION: Inspectors should be aware of the following when evaluating an operator's justification to exclude the internal corrosion threat.

    - Such justifications should be based in part on a previous high resolution MFL ILI capable of discriminating between internal corrosion and external corrosion metal loss. A line should be completely free of any internal corrosion metal loss before it can be considered as a candidate to exclude the internal corrosion threat.
    - Even a line that is shown to be free of internal corrosion defects may have the potential for internal corrosion in the future.
    - All portions of lines may not be piggable, such as crossovers and delivery laterals. This was the case in the Carlsbad incident. Inspectors should use care to verify that operators are not excluding line segments associated with transmission mains if those other segments have not had an ILI assessment.
    - A line with an ILI that showed internal corrosion metal loss that was repaired is not a good candidate for exclusion since known internal corrosion history is present and the repair might not have corrected the cause of the internal corrosion. Any line with previous internal corrosion history must have a strong basis for concluding that the root cause of the previous internal corrosion has been corrected and there is not further opportunity for internal corrosion (which should be verified by no detectable internal corrosion in 2 consecutive ILI assessments.)
    - Other assessment methods, including hydro and ICDA, do not verify that there is no past or ongoing internal corrosion on a line. Therefore, it is problematic to conclude that the internal corrosion threat does not exist based on these types of assessments. Operators that attempt to use these assessment methods to exclude the threat of internal corrosion should have a compelling technical justification that includes additional analysis such as (but not limited to) a thorough evaluation of gas quality records, justification that drips and low points are clean and dry, etc. The burden of proof that internal corrosion is not a threat should be very high in these cases.
    - Any line excluded from the internal corrosion threat must have proven ongoing gas quality monitoring. In the case of a line with previous ILI assessments, the gas monitoring must have been in place for a significant period of time prior to the assessment, in order to verify that conditions introduced into the line might not exist that could cause future corrosion subsequent to the ILI assessment.
    - Drips and low points are particularly susceptible to collecting water/liquids and an operator must have a program to confirm that no internal corrosion is ongoing at these locations.
- STRESS CORROSION CRACKING (SCC): Inspectors should be aware of the following when evaluating an operator's justification to exclude the internal corrosion threat.
    - Both ASME B31.8S-2004, Appendix A3.2, and NACE RP 0402-2004, list the following as screening criteria for SCC assessments:
        - Operating stress > 60% SMYS
        - Operating temperature >100F (this criteria does not apply to near neutral pH SCC)
        - Location less than 20 miles downstream of compressor station
        - Age of pipeline > 10 yrs
        - Any coating type other than FBE
    - These criteria do not account for approximately 25-35% of historical SCC failures.
    - As stated in NACE RP-0204-2004, Section 1.2.1, "It is recognized that these screening factors will identify a substantial percentage of the susceptible locations, but not necessarily all of them."
    - Operators with historical SCC failures in locations that are outside of these screening criteria should adjust screening criteria to reflect its operating history when performing its threat identification, risk analysis, and assessment plans.
    - Lack of failures that have been attributed to SCC, alone, is insufficient reason to discount the SCC threat. Prior to the mid-1990s, many operators did not routinely perform metallurgical examination of failed pipe. It is postulated that some historical failures might have been caused by, but not attributed to, SCC.

- See Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., October 2004, (Reference: VINTAGE) for discussion of threats that should be considered for specific pipeline types and some threats are not considered threats by the report's authors.
- "**SHOULD**" Requirement: Performance based integrity management programs that use more comprehensive analysis methods **should** consider the following in order to exclude a threat in a segment [Re: ASME B31.8S-2004, Section 5.10 and Protocol L.03]:

    a. There is no history of a threat impacting the particular segment or pipeline system.
    b. The threat is not supported by applicable industry data or experience.
    c. The threat is not implied by related data elements.
    d. The threat is not supported by like/similar analyses.
    e. The threat is not applicable to system or segment operating conditions.

C.02 Data Gathering and Integration

Verify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated. [§192.917(b)]

C.02 *Supplemental Guidance:*

- Protocol C.02 encompasses rule requirements for both data gathering and data integration.
- The focus of the data effort covered by this protocol is the assembly and analysis of data input to the operator's risk assessment, the results of which support decisions in all other integrity management program elements.
- An important distinction to consider when inspecting for the requirements related to this protocol is the difference between data INTEGRATION and data AGGREGATION. Operators should not simply put several types of information into a single location and assume that such an exercise constitutes data integration. The most important aspect of data integration is the ANALYSIS of aggregated data in order to discern integrity threats and risks that would not otherwise be observed from independently reviewing the various individual data elements. The operator's process should address how it does both data aggregation and data integration (analysis of aggregated data.) FAQ-240 further clarifies PHMSA expectations for data aggregation and integration.
- Refer to Supplemental Guidance Appendix C.01, Bookmark C2, Protocol Guidance for Identification of Threats, Data Integration, and Risk Assessment, for additional guidance on Protocol C.02.
- Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration.
- Also refer to Supplemental Guidance Appendix C.03, White Paper, "Look Beyond" Provisions, which addresses requirements for actions to be taken for non-covered segments. Data gathering and data integration applies to the entire pipeline, not just covered segments.

C.02.a. Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4]

C.02.a. Supplemental Guidance:

- 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.
- Section 192.917(b) requires that operators gather and integrate existing data "on the entire pipeline" that could be relevant to covered segments as part of performing their risk assessment. Refer to FAQ-222. The data plan must address data activities for the entire pipeline.

- Regardless of which type of program is in use by the operator (PRESCRIPTIVE OR PERFORMANCE-BASED), the operator must have a "comprehensive" plan for data collection, integration, and analysis. The plan should address the following aspects of the data process:
    - Storage
    - Retrieval
    - "Granularity"
    - Collection
    - Aggregation
    - Integration (analysis)
- The plan should also take into account the following aspects of the data itself:
    - Age
    - Resolution
    - Units of measure
    - Accuracy of location data
    - Quality
    - Consistency
    - Metadata (data about the data including where and how the data was obtained and used and the other data attributes specified above.)
- 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.

C.02.b. Verify that the operator has assembled data sets for threat identification and risk assessment according to the requirements in ASME B31.8S-2004, Section 4.2, ASME B31.8S-2004, Section 4.3, and ASME B31.8S-2004, Section 4.4. 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 [§192.917(b)]:

1. Past incident history
2. Corrosion control records
3. Continuing surveillance records
4. Patrolling records
5. Maintenance history
6. Internal inspection records
7. All other conditions specific to each pipeline.

C.02.b. Supplemental Guidance:

- For PRESCRIPTIVE programs:
    - Operators must use all of the data elements in ASME B31.8S-2004, Appendix A, which are summarized in ASME B31.8S-2004, Table 1. Also refer to "Effectiveness of Data Integration in Pipeline Integrity Management Programs", Baker TTO-9, (draft-to be incorporated later).
        - FAQ-81 states that an operator must consider all information relevant to determining risk associated with pipeline operation in HCAs.
    - If any data element is missing, the operator must assume that the threat applies to the line being evaluated. The implication of this requirement is that if a line has missing data specified in ASME B31.8S-2004, Appendix A, then the line must be assessed for that threat.
    - The data elements listed in §192.917(b) must be considered for both covered and non-covered segments. Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration.
    - Supplemental Guidance Appendix E.02, Bookmark E04, Integrated Analysis of Assessment Data provides additional discussion on the integration of data such as:
        - ILI results (past and current),

        - hydrostatic pressure test results (root cause of test failures and pressure reversals),
        - ROW data (indicators of TPD risk),
        - corrosion protection (coating and CP systems),
        - maintenance (repairs, etc.), and
        - other available information
- For PERFORMANCE-BASED programs:
    - Operators shall collect at minimum the data elements specified under the prescriptive based program requirements.
    - The additional quantity and specific data elements needed for a performance-based program are not specified and will vary depending on the pipeline system.
    - An operator may not use the performance-based approach if any of the data elements are missing.
    - Increasingly complex risk assessment methods require more data elements than those listed in ASME B31.8S-2004, Appendix A, as summarized in ASME B31.8S-2004, Table 1. In general, "increasingly complex risk assessment methods" is understood to mean scenario-based models and probabilistic models.
    - Initial data elements must be sufficient to support integrity assessment plans.
    - Additional data elements should be expanded over time to support general pipeline and facility risk assessments.
    - Improvements should include support for the determination of additional preventive and mitigative actions.
    - The data elements listed in §192.917(b) must be considered for both covered and non-covered segments. Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration.
    - FAQ-83 addresses the need for operators to address geotechnical and soil instability risks.
- "**SHOULD**" Requirement: Every effort **should** be made to utilize all of the actual data for the pipeline or facility. Generalized integrity assumptions used in place of specific data elements **should** be avoided. (Re: ASME B31.8S-2004, Section 4.4) [Re: Protocol L.03]

C.02.c. Verify that the operator has utilized the data sources listed in ASME B31.8S-2004, Table 2, for initiation of the integrity management program. [ASME B31.8S-2004, Section 4.3]

C.02.c. Supplemental Guidance:

- All available sources listed in ASME B31.8S-2004, Table 2 should be employed to fill out the data elements required for risk assessment (see Protocol C.02.b).
- If one or more sources from ASME B31.8S-2004, Table 2 is not available, the operator must take reasonable action to obtain the data. Data that cannot be obtained from records must be supplemented by expert opinion (see Protocol C.03) in the operator risk assessment.
- In no case is the unavailability of data a justification for dismissing a threat from consideration or treating a threat as a low risk (see Protocol C.02.d).
- Operators should make use of any root cause analysis of previous failures as a potential valuable data source.
- Refer to Supplemental Guidance Appendix C.01, Bookmark C2c, Protocol Guidance for Identification of Threats, Data Integration, and Risk Assessment, for additional guidance on Protocol C.02.c.

C.02.d. Verify that the operator has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME B31.8S-2004, Section 4.1, ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, ASME B31.8S-2004, Section 5.7(e), and ASME B31.8S-2004, Appendix A]:

i. Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat.
ii. Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.
iii. Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered.
iv. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

C.02.d. Supplemental Guidance:

- The operator needs provisions for checking data accuracy in the IM program.
- If the operator employs suspect or uncertain data, or if data are not available for variables that are part of the operator's risk assessment method, then the operator is required to treat this situation in a "conservative" manner. The operator's IM program must provide for the following:
    - Any threats related to the data deficiency are assumed to apply.
    - Conservative assumptions must be employed in the risk assessment for the threat and segment involved.
    - Written documentation of the effect of the data deficiency on the risk assessment results are required. One way to achieve this would be for the operator to conduct "sensitivity analysis" to determine the magnitude of the effect of the data deficiency.
    - If the effect of the data deficiency is found to be significant, then the operator is required to correct the data deficiency through additional data collection.
- "**SHOULD**" Requirement: For missing or questionable data, the operator **should** determine and document the default values that will be used and why they were chosen. The operator **should** choose default values that conservatively reflect the values of other similar segments on the pipeline or in the operator's system. (Re: ASME B31.8S-2004, Section 5.7 (e)) [Re: Protocol L.03]

C.02.e. Verify that the operator's program includes measures to ensure that new information is incorporated in a timely and effective manner, as addressed in Protocol K. [§192.911(k), ASME B31.8S-2004, Section 11(b) and ASME B31.8S-2004, Section 11(d)]

C.02.e. Supplemental Guidance:

- Operator integrity decisions are based on risk assessment results based on numerous required data elements (Protocol C.02.b above) and utilizing numerous diverse data sources (Protocol C.02.c above). To ensure these results are based on the best current information about the pipeline, the operator's program must ensure that new information is incorporated in a timely manner.
- The inspection should verify that:
    - The operator's program includes provisions that ensure the timely incorporation of new information from the required data sources for the required data elements ***and***
    - The operator has carried out data updates in conformance with program requirements.

C.02.f. Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes:

i. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S-2004, Section 4.5];
ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)].

C.02.f. Supplemental Guidance:

- The fundamental function of the operator's risk assessment is to associate threats and risk levels with specific locations on the operator's pipeline. Operators must have a means of relating the data on threats and pipeline risk factors to the correct locations on the pipeline.
- Specifically, in order to carry out the data integration needed for the threat evaluation required for residual third party damage (see Supplementary Guidance Appendix B.07, White Paper, Assessing for Third Party Damage), operators must have a means of accurately locating potential residual third party damage identified by ILI or ECDA in comparison to locations of encroachments and foreign line crossings. For a more detailed discussion of the integrated review of ILI results, see Appendix E.02, Bookmark E04. A detailed review of data integration with ECDA results is addressed in Protocol D.
- FAQ-240 clarifies PHMSA expectations for data integration. Data integration includes both the aggregation of data and the analysis of aggregated data to identify integrity threats or insights that might not otherwise be discovered.

C.03 Risk Assessment

Verify that the operator has conducted a risk assessment that follows ASME B31.8S-2004, Section 5, and that considers the identified threats for each covered segment. [§192.917(c)] [Note: Application of the risk assessment to prioritize the covered segments for the baseline assessment is covered in Protocol B, continual reassessments in Protocol F, and additional preventive and mitigative measures in Protocol H.]

C.03 *Supplemental Guidance:*

- Protocol C.03 encompasses requirements for operator risk assessment, by which the operator conducts an analysis of risk for all covered segments and all identified threats (see Protocol C.01), using the information obtained from the data collection and integration (Protocol C.02)
- Risk Assessment is necessary to support integrity decisions required by the IM rule, including
    - Scheduling baseline integrity assessments (Protocol B.02) and re-assessments (Protocol F.04)
    - Implementing additional preventive and mitigative measures (Protocol H)

C.03.a. Verify that the operator's risk assessment supports the following objectives [ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.4]:

i. prioritization of pipelines/segments for scheduling integrity assessments and mitigating action
ii. assessment of the benefits derived from mitigating action
iii. determination of the most effective mitigation measures for the identified threats
iv. assessment of the integrity impact from modified inspection intervals
v. assessment of the use of or need for alternative inspection methodologies
vi. more effective resource allocation
vii. facilitation of decisions to address risks along a pipeline or within a facility

C.03.a. Supplemental Guidance:

- 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 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).
    - Establish re-assessment intervals according to segment risks

    - Decisions on preventive and mitigative measures in order to achieve additional risk reduction beyond integrity assessment and repair activities
- The operator's risk assessment needs to produce results that support these required IM program elements. The operator's program must document:
    - how the risk assessment is conducted,
    - the results that will be produced,
    - how these results are used to meet rule requirements,
    - the input information needed to produce the risk results
    - the method or methods used to produce the results (see Protocol C.03.b below)
- "**SHOULD**" Requirement: The risk drivers for each high-risk segment **should** be considered in determining the most effective integrity assessment and/or mitigation option. (Re: ASME B31.8S-2004, Section 5.11) [Re: Protocol L.03]
- If the operator is performing any of the tasks described by objectives (i) through (vii), it must apply its risk assessment as a tool in doing so.

C.03.b. Verify that the operator utilizes one or more of the following risk assessment approaches [ASME B31.8S-2004, Section 5.5]:

i. Subject matter experts (SMEs),
ii. Relative assessment models,
iii. Scenario-based models, or
iv. Probabilistic models

C.03.b. Supplemental Guidance:

- The rule allows any of the four listed approaches to be used. By far, the most common approaches are expected to be subject matter expert evaluations and "relative assessment" (index) models.
- More than one risk assessment approach may be used by operators. For example, it is common to use expert group evaluations in conjunction with risk models. It is also possible that different models may be used to support different IM program elements.
- If SME processes are employed the operator's program must thoroughly document how expert opinion and subjective information are used to produce consistent results and how these results are used to support integrity decisions that must be derived from risk results (see Protocol C.03.a above).
- FAQ-166 addresses qualification standards that apply to subject matter experts.
- FAQ-168 addresses PHMSA expectations with regard to the use of the four risk assessment approaches.
- Refer to Supplemental Guidance Appendix C.01, Bookmark C3b, Protocol Guidance for Identification of Threats, Data Integration, and Risk Assessment, for additional guidance on Protocol C.03.b.
    - Subject matter experts (SMEs), Supplemental Guidance Appendix C.01, Bookmark SME
    - Relative assessment models, Supplemental Guidance Appendix C.01, Bookmark Relative
    - Scenario-based models, Supplemental Guidance Appendix C.01, Bookmark Scenario
    - Probabilistic models, Supplemental Guidance Appendix C.01, Bookmark Probabilistic
- An example risk estimation model is provided in Supplemental Guidance Appendix C.01, Bookmark Example

C.03.c. Verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential releases, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment. [ASME B31.8S-2004, Section 3.1, ASME B31.8S-2004, Section 3.3, ASME B31.8S-2004, Section 5.2, ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.7(j)] Verify that the risk assessment approach includes the following characteristics:

i. The risk assessment approach contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, Section 5.7(a)];
ii. The risk assessment considers the frequency and consequences of past events, using company and industry data [ASME B31.8S-2004, Section 5.7(c)];
iii. The risk assessment approach integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S-2004, Section 5.7(d)];
iv. The risk assessment process includes a structured set of weighting factors to indicate the relative level of influence of each risk assessment component [ASME B31.8S-2004, Section 5.7(i)];
v. The risk assessment process incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S-2004, Section 5.7(k)].

C.03.c. Supplemental Guidance:

- The rule specifies that the operator's risk assessment shall be conducted according to ASME B31.8S-2004, Section 5. ASME B31.8S-2004, Section 5.2, defines risk to include consideration of *both* likelihood and consequences of failure and cites ASME B31.8S-2004, Section 3, for how consequences shall be considered (see ASME B31.8S-2004, Section 3.3). It is stressed that operators must consider consequences in some way in conducting risk assessment and applying risk results to integrity management program elements.
- The rule and ASME standard specify required characteristics of the operator's risk assessment approach. These requirements include:
    - A logical, documented structure defined in the IM program
    - Incorporation of operating and failure history (both operator-specific and applicable industry events) in the risk evaluation, considering both frequency and consequence of different categories of failures
    - Incorporation of the results of integrity assessments (e.g., location, magnitude and density of identified defects) and other pipeline inspections as risk factors in the risk evaluation. This includes:
        - Integrated analysis of assessment results with other data (re: Appendix E.02, Bookmark E04.)
        - Root cause analysis of Subpart J pressure test failures, especially pressure reversals (re: Appendix E.02, Bookmark E06).
        - Integrated analysis of ECDA indirect assessment data with other data (re: Protocol D).
    - Risk factors (threats and consequences) weighted according to their relative significance to risk
    - Risk assessment results broken down into small enough units so that the variation in risk along the pipeline is accurately represented
- FAQ-125 provides guidance on risk ranking by piggable sections. The rule requires that an operator must use risk assessment to prioritize covered segments for baseline assessments and reassessments (§192.917(c)).
- Refer to Supplemental Guidance Appendix C.01, Bookmark C3c, Protocol Guidance for Identification of Threats, Data Integration, and Risk Assessment, for additional guidance on Protocol C.03.c.
- "**SHOULD**" Requirement: The output of a risk assessment **should** include the nature and locations of the most significant risks to the pipeline (Re: ASME B31.8S-2004, Section 2.3.3) [Re: Protocol L.03]
- "**SHOULD**" Requirement: The operator **should** tailor the [risk assessment] method to meet the needs of the system.(Re: ASME B31.8S-2004, Section 2.3.3) [Re: Protocol L.03]
- "**SHOULD**" Requirement: Preferably, [consideration of operating/failure history] **should** include the subject pipeline system or a similar system but other industry data can be used where sufficient data is initially not available. (Re: ASME B31.8S-2004, Section 5.7 (c)) [Re: Protocol L.03]
- "**SHOULD**" Requirement: To be effective, a risk assessment method **should** be able to identify pipeline integrity threats previously not considered. (Re: ASME B31.8S-2004, Section 5.7 (d))

[Re: Protocol L.03] Note: Integrated analysis of ILI results with other data is an important aspect of identifying threats not previously considered. Refer to Appendix E.02, Bookmark E04.

- "**SHOULD**" Requirement: An effective risk model **should** contain the structure necessary to perform "what if" calculations.(Re: ASME B31.8S-2004, Section 5.7 (h)) [Re: Protocol L.03]
- "**SHOULD**" Requirement: All threats and consequences contained in a relative risk assessment process **should** not have the same level of influence on the risk estimate. (Re: ASME B31.8S-2004, Section 5.7 (i)) [Re: Protocol L.03]
- "**SHOULD**" Requirement: [The risk assessment process] **should** also provide for several types of data evaluation and comparisons, establishing which particular threats or factors are primary risk "drivers" or have the most influence on the result. (Re: ASME B31.8S-2004, Section 5.7 (j)) [Re: Protocol L.03]
- "**SHOULD**" Requirement: The operator **should** assess risk factors that cause higher risk levels for particular segments.(Re: ASME B31.8S-2004, Section 5.10) [Re: Protocol L.03]
- "**SHOULD**" Requirement: When segments being compared have similar risk values, the failure probability and consequences **should** be considered separately. (Re: ASME B31.8S-2004, Section 5.10) [Re: Protocol L.03]

C.03.d. Verify that the operator's process provides for revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments. Verify that the provisions for change to the risk assessment address the following areas:

i. the risk assessment plan calls for recalculating the risk for each segment to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions [ASME B31.8S-2004, Section 5.11, and ASME B31.8S-2004, Section 5.7(c)]
ii. the operator integrates the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates [ASME B31.8S-2004, Section 5.4]
iii. the integrity management plan calls for revision to the risk assessment process if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments [§192.917(c) and ASME B31.8S-2004, Section 5.12]
iv. the operator uses a feedback mechanism to ensure that the risk model is subject to continuous validation and improvement [§192.917(c) and ASME B31.8S-2004, Section 5.7(f)]

C.03.d. Supplemental Guidance:

- This protocol subquestion is included to capture requirements that ensure that risk assessments results continue to represent pipeline risk as conditions change over time and new information on the pipeline is obtained. The operator's program must include written provisions to ensure that these requirements are met. In addition, inspectors should verify that physical and programmatic changes have been identified and reflected appropriately in the operator's risk assessment.
- 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. Inspectors should verify that the risk assessment plan requires that the risk for each segment be periodically updated to reflect:
    - The results from integrity assessments
    - completed prevention and mitigation actions;
- If pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments, then the corrected data should be used when the risk results are updated
- In order to ensure that updated risk results reflect changes along the pipeline, the operator needs to integrate the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary. Procedures governing these functions need to include provisions for capturing changes and communicating them to the groups conducting the risk assessment
- The operator is required to use a feedback mechanism to ensure that the risk model (if used) is subject to continuous validation and improvement. The model results should be regularly reviewed

and changes made as needed. The risk model feedback mechanism must be documented in the IM program. Major changes to the operator's risk assessment model and process should be part of the formal management of change (MOC) process. Examples of major changes include:
    - Addition of new risk factors (representing threats or consequence categories) to the risk model
    - Deletion of risk factors from the risk model
    - Changes to the relative numerical weighting of risk factors within the risk model
    - Changes to the algorithm defining how risk factor data is combined in the risk model
- Not all changes to risk assessment processes and models need be approved through a formal MOC process. Some updates to the risk model are expected to be performed semi-continuously and should not be subjected to a formal change control process. For example, new or updated data for risk factors should be incorporated in the risk assessment as soon as available.
- Inspectors should note that there are 2 potentially contradictory statements concerning risk re-evaluation in ASME B31.8S-2004, Section 5.8: "A specified period defined by the operator shall be established for a system wide risk re-evaluation but shall not exceed the maximum required interval". It goes on one sentence later to state "The frequency of the system wide re-evaluation must be at least annually but may be more frequent based on the frequency and importance of data modifications." PHMSA generally expects that the risk analyses will be re-evaluated at a minimum on an annual basis (refer to FAQ-234). More frequent review may be necessary if conditions warrant.
- FAQ-142 addresses requirements related to the timing for conduct of risk assessments.
- FAQ-234 states that operators should re-evaluate risk annually. This should include consideration of any new information identified during the annual review of high consequence areas, results of assessments conducted during the year, and any changes to the pipeline system or its operations.
- "**SHOULD**" Requirement: Like the risk process itself, [the risk assessment] document **should** be periodically updated as modifications or risk process changes are incorporated. (Re: ASME B31.8S-2004, Section 5.7 (g)) [Re: Protocol L.03]
- "**SHOULD**" Requirement: Such a re-evaluation [of risk] **should** include all pipelines or segments included in the risk analysis process to assure that the most recent inspection results and information is reflected in the re-evaluation and any risk comparisons are on an equal basis. (Re: ASME B31.8S-2004, Section 5.8) [Re: Protocol L.03]
- "**SHOULD**" Requirement: Risk assessment **should** be performed periodically to include new information, consider changes made to the pipeline system or segment, incorporate any external changes, and consider new scientific techniques that have been developed and commercialized since the last assessment. (Re: ASME B31.8S-2004, Section 8.3.2) [Re: Protocol L.03]

C.03.e. Verify that adequate time and personnel have been allocated to permit effective completion of the selected risk assessment approach. [ASME B31.8S-2004, Section 5.7(b)]

C.03.e. Supplemental Guidance:

- Application of adequate time and resources will require a subjective conclusion by inspectors.
- It is important that the operator is not merely "going through the motions", but is making a good-faith effort to assess segment risks and base integrity management program decisions on risk criteria. If the operator's risk assessment effort does not adequately support these decisions, then one reason may be inadequate time and resources.
- Risk Assessment can be labor-intensive, requiring major information assembly efforts and potentially time-consuming facilitated evaluation sessions involving "Subject Matter Experts." Documentation of risk process inputs, evaluations, and results can require a major commitment of labor resources.

C.04 Validation of the Risk Assessment

Verify that the integrity management program identifies and documents a process to validate the results of the risk assessments. [§192.917(c) and ASME B31.8S-2004, Section 5.12]

C.04 *Supplemental Guidance:*

- Risk assessment validation is a characteristic of effective risk assessment programs for prescriptive and performance-based integrity management programs.
- The operator's risk assessment process must include elements for validation of results. What is called for is some kind of "sanity check", so that decisions are not hard-wired to output from a 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 if 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. However, if there is wide variance that cannot be justified, then some adjustment to risk assessment inputs or the model structure may be necessary. Changes and the reasons for the changes must be documented. After any needed changes are made, the revised results also need to be reviewed and validated.
- **"SHOULD"** Requirement: Risk assessment methods alone **should** not be completely relied upon to establish risk estimates or to address or mitigate known risks. Risk assessment methods should be used in conjunction with knowledgeable, experienced personnel (subject matter experts and people familiar with the facilities) that regularly review the data input, assumptions, and results of the risk assessments. Such experience based reviews **should** validate risk assessment output with other relevant factors not included in the process, the impact of assumptions, or the potential risk variability caused by missing or estimated data.(Re: ASME B31.8S-2004, Section 5.4) [Re: Protocol L.03]

C.04.a. Verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience. [§192.917(c) and ASME B31.8S-2004, Section 5.12]

C.04.a. Supplemental Guidance:

- The operator's IMP should specify processes used to validate the results of their risk assessments. Checks should be included to ensure the risk assessment results are both logical and consistent with the operator's knowledge of pipeline characteristics and industry experience.
- The operator may employ various means to achieve validation. Elements of validation may include:
    - Team review of results
    - SME reviews
    - Review of lessons learned from industry

C.05 Plastic Transmission Pipeline

If the operator has plastic transmission pipelines, verify that the operator assesses applicable threats to each covered segment of plastic line. [§192.917(d)]

C.05 *Supplemental Guidance:*

- This protocol only applies if the operator has plastic gas transmission pipeline segments. This may occur if operators have a line that transports gas from a gathering line or storage facility to a single large volume customer such as a power plant, factory or institutional user.

C.05.a. If the operator has plastic transmission lines, 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. [§192.917(d)]

C.05.a. Supplemental Guidance:

- If the operator has plastic transmission lines, Protocol C.05 is used to 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.
- The principal threats for plastic pipe are considered to be:
    - Third Party Damage
    - Other Outside Force Damage (e.g., ground movement
    - Some manufacturing defects for 1970s-era plastic pipe
    - Some materials defects producing cold-weather brittle conditions for plastic pipe
- Some construction defects (e.g., poor joints)

Protocol Area D. DA Plan

- D.01 ECDA Programmatic Requirements
- D.02 ECDA Pre-Assessment
- D.03 ECDA Indirect Examination
- D.04 ECDA Direct Examination
- D.05 ECDA Post-Assessment
- D.06 Dry Gas ICDA Programmatic Requirements
- D.07 Dry Gas ICDA Pre-Assessment, Region Identification and Use of Model
- D.08 Dry Gas ICDA Direct Examination
- D.09 Dry Gas ICDA Post-Assessment
- D.10 Wet Gas ICDA Programmatic Requirements
- D.11 SCCDA Data Gathering and Evaluation
- D.12 SCCDA Assessment, Examination and Threat Remediation
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D.01 ECDA Programmatic Requirements

If the operator elects to use ECDA, verify that the operator develops and implements an ECDA plan in accordance with §192.925.

D.01 *Supplemental Guidance:*

- 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 RP0502-2002. In addition to specific procedures, the plan must explain:
    - the objectives of what will be accomplished,
    - how specific work activities are to be accomplished,
    - 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
- The operator must be able to demonstrate the plan has been implemented by records that document the results of the ECDA activities.
- The operator's plan must provide for periodic updates due to lessons learned - see NACE RP0502-2002, Section 6.5.1.
- The Gas Technology Institute (GTI) and the American Gas Association (AGA) have developed a collaborative research program to help Local Distribution Companies who operate high-pressure natural gas transmission lines understand the methods and procedures to perform integrity assessments and meet IM regulations. This program developed a standard ECDA inspection protocol to assist these operators in implementing NACE RP0502-2002. The GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol is available in the IMDB File Library.
- FAQ-187 clarifies that like all assessment methods, direct assessment can only be used in situations for which it is applicable. Direct assessment is not applicable for all threats.

D.01.a. Verify that the operator developed a documented ECDA plan, and developed procedures to implement the plan. [§192.925(b)]

D.01.a. Supplemental Guidance:

- The operator's procedures should describe the details of who, what, where, when and how for each of the four ECDA steps - pre-assessment, indirect examination, direct examination and post assessment. Procedure details should include:
    - how these four steps will be implemented,
    - the criteria used in making decisions in implementing each process step,
    - who is responsible for accomplishing key activities,
    - the qualifications and how those individuals are trained in the plan and kept informed of up to date of changes in the plan,
    - when and how such functions and activities are to be accomplished'
    - procedures should be in sufficient detail to act as instructions to employees,
    - definitions used in the operator's plans and procedures should be consistent with those defined in the rule and referenced standards
- The plan must address all of the requirements contained in §192.925, ASME B31.8S-2004, Section 6.4, as well as all of the requirements contained in NACE RP0502-2002.
- FAQ-155 clarifies that requirements in the standards, and even statements in the standards that are portrayed therein as non-mandatory have the full effect of the Rule when invoked by the Rule.
- FAQ-167 clarifies that "must" and "shall" statements made in invoked portions of the standards represent requirements, while "should" statements represent actions that "should" be taken but may not be based on an appropriate justification. Also refer to Protocol L.03.

D.02 ECDA Pre-Assessment

Verify that the ECDA Pre-assessment process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502-2002 to (1) determine if ECDA is feasible for the pipeline to be evaluated, (2) identify ECDA regions and (3) select Indirect Inspection Tools. [§192.925(b)(1)]

D.02 *Supplemental Guidance:*

- The purpose of pre-assessment is threefold,
    - To determine which areas the ECDA process is feasible for evaluating the integrity of an operator's pipeline,
    - To identify which indirect inspection tools work reliably in those areas or ECDA regions, and
    - To identify the characteristics and limits of pipeline areas called ECDA regions.
- Selecting which two Complementary Tools will be used for each region is a key result of the pre-assessment step.
- For the initial ECDA on a region, operators must apply and document more restrictive criteria.

D.02.a. Verify that the operator **identifies and collects adequate data** to support ECDA pre-assessment. [NACE RP0502-2002, Section 3.2]

D.02.a. Supplemental Guidance:

- Review the operators' documentation to verify the pipeline operator has:
    - Defined minimum data requirements critical to the success of the ECDA process. (NACE RP0502-2002, Section 3.2.1), and addressed insufficient data, or instances where critical data could not be collected,

    - Collected data in the five categories of NACE RP0502-2002, Table 1, ECDA Data Elements,
    - Has a process to analyze this data to identify ECDA regions and a basis upon which each indirect assessment tool will be selected,
    - Has included historical and current data along with physical information for each segment to be evaluated
- Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration
- A successful ECDA process is being able to analyze data to identify ECDA regions, a basis upon which to select indirect examination tools for these regions and determine feasibility of applying ECDA to each segment.

D.02.b. Verify that the operator conducts an ECDA **feasibility assessment** by integrating and analyzing the data collected. [NACE RP0502-2002, Section 3.3]

D.02.b. Supplemental Guidance:

- Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration.
- The operator must be able to demonstrate its feasibility assessment processes.
- Review the operators' documentation to verify the operator has a process to integrate and analyze its data to:
    - Determine Indirect examination tool reliability
    - Establish Region characteristics
    - Identify and address locations where indirect tools may not provide accurate readings.
- Determine how the operator addresses feasibility where data is insufficient, or critical data can't be collected. . Some examples of data elements essential to the feasibility of an ECDA are:
    - Where is the pipe coated or bare or where it changes from one to the other (needed to set ECDA regions and select the proper indirect inspection tools). Operators can perform test holes to determine where the coating starts and ends and if the pipe is bare.
    - At any time where there were periods of time that the pipeline did not have or had insufficient cathodic protection (needed to determine if there is active or prior corrosion damage). Operators can assume that the pipeline did not have sufficient cathodic protection and that all corrosion is active and thus must be mitigated.
    - Areas that have MIC and one or more other potential issue (stray DC currents and/or coating disbondment or coating failure along with MIC can accelerate external corrosion rates). Operators in these situations must use the worst case for the corrosion growth rate of 16 mils per year and should take immediate steps to mitigate the MIC by raising cathodic potentials and replacing damaged coatings and mitigating the stray current problem by providing another path for the strays to return to the proper location
    - Is the CP system type either unknown or a combination of both types (some indirect inspection tools may not be appropriate for one or the other type of CP systems). Operators may need to use additional indirect inspection tools to overcome the lack of knowledge of the CP systems or they may need to reduce the size of ECDA regions to areas where everything is known and ECDA regions where some data elements may not be known and thus additional inspections are needed.
    - Route changes, diameter changes and other modifications may require that the ECDA region be changed (These changes can affect the tool selection and the tool sensitivity making comparison of indications difficult). Operators can compensate for these unknowns by raising the severity of all indications found in such areas. If such areas are unknown, then all indications should have their severity raised.
    - Prior uses of the pipe and/or possible reconditioning of pipe or recoating of corroded pipe (Operators who suspect use of reconditioned pipe should make test holes to inspect the pipe condition and determine if the pipe has been recoated and if it had corrosion problems in the past) If an operator can not determine if the pipe has been reconditioned (and does not have any evidence of the pipe being new at the time of installation) they

should down grade the pipe to the lowest grade of pipe and assume that all indications are classified as severe (and excavated).

- ECDA may not be used for regions where the operator is unable to identify two reliable, effective, and complementary indirect tools. (NACE RP0502-2002, Section 3.2.4)
- ECDA might not be feasible where:
  - Coatings are disbonded
  - Backfill has significant rock content
  - Ground surfaces have multi layered pavement or rebar
  - Areas contain adjacent buried metallic structures
  - Areas contain stray current or DC railroads
  - Casings
  - Underwater crossings
- Operators may be able to perform ECDA in problematic areas by implementing additional testing requirements, using additional indirect inspection tools, or utilizing different testing procedures. Some examples of these are discussed in Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on Problematic Areas.
  - FAQ-243 addresses PHMSA expectations for determining if ECDA is feasible.

D.02.c. Verify that the operator complies with all requirements for appropriate indirect inspection **tools selection**: [NACE RP0502-2002, Section 3.4, NACE RP0502-2002, Table 2, and 192.925(b)(1)(ii)]

i. A minimum of 2 complementary tools must be selected such that the strengths of one tool compensate for the limitations of the other tool. (Note: The operator must consider whether more than two indirect inspection tools are needed to reliably detect corrosion activity.)
ii. Tools are able to assess and reliably detect corrosion activity and/or coating holidays.
iii. Verify that the operator documents the basis for its tool selection.
iv. If the operator utilizes an indirect inspection method not listed in NACE RP0502-2002, Appendix A, verify that the operator justifies and documents the method's applicability, validation basis, equipment used, application procedure, and utilization of data. [§192.925(b)(1)(ii)]

D.02.c. Supplemental Guidance:

- Each operator must identify:
  - Two complementary indirect examination tools for each region
  - Document the basis for their tool selections.
- The operators' records must document the conditions and environment surrounding the pipeline and why each tool's effectiveness is the best match for the region. Generally, an operator should endeavor to use tools based on different technologies. Refer to the following FAQs:
  - FAQ-175 states that NACE describes complementary as: "the strengths of one tool compensate for the limitations of another."
  - FAQ-129 clarifies that indirect assessment methods other than those presented in the NACE standard may be used, however operators must demonstrate their applicability, validation basis, equipment used, application procedure, and utilization of data for the methods selected.
- Indirect examination tool effectiveness varies with soils, rock in backfill, pipe coatings, Signal interference conditions, depth of cover, construction practices, etc.
  - Most of the ECDA indirect inspection tools have some limitations regarding their use in determining acceptable cathodic protection levels or coating holidays. In NACE RP 0502 Table 1, there is some mention of the limitations. When using CIS on large (30" and above) this indirect inspection tool can have areas of poor cathodic protection near the bottom of the pipe masked by the size of the pipe and the depth of the bottom of the pipe (a 48" pipe with 5' of cover would have the bottom at 7' under grade). Other micro holiday tools like DCVG could have trouble finding small coating holidays on small pipe such as 1" or smaller. These limitations can and will vary depending on environmental

conditions, coating condition, soil type and soil resistivity. As a general rule of thumb, very large and very small pipes can be problematic for some indirect inspection tools.

- Refer to NACE RP0502-2002, Table 2, ECDA Tool Selection Matrix, and NACE RP0502-2002, Appendix A, Indirect Inspection Methods, for a discussion of indirect tools that may be used.
- Use of guided wave UT as a complementary tool as part of ECDA is an acceptable use of that technology. However, use of guided wave technology alone, as an examination method or as an alternative to excavating pipeline to conduct a direct examination would be considered "other technology" and requires notification to PHMSA prior to use. Similarly, use of close interval survey/overline survey methods is acceptable as complementary methods. However, use of close interval survey/overline survey would not be considered acceptable if not used in conjunction with some other technology. NACE RP0502-2002, Table 2 provides guidance on tool selection, and identifies conditions under which indirect tools are unreliable. Refer to the following FAQs:
    - FAQ-198 states that if guided wave UT is used as one of the complementary tools for indirect inspections as part of ECDA, it would not be considered other technology.
    - FAQ-204 clarifies that close interval survey/overline survey are indirect measurement techniques that can be used in ECDA. If used in that context, and in conformance with NACE RP0502-2002, these techniques would not represent "other technology".

D.02.d. Verify that the operator **identifies ECDA Regions** based on the use of data integration results applied to specified criteria. [NACE RP0502-2002, Section 3.5]

D.02.d. Supplemental Guidance:

- An ECDA region is a section or sections of a pipeline segment with similar physical characteristics, operating histories, expected future corrosion conditions and in which the same indirect inspection tools are used. (NACE RP0502-2002, Section 3.5.1.1.1)
- NACE RP0502-2002, Table 1, ECDA Data Elements, provides guidance in identifying ECDA Regions. All pipeline segments in HCAs should be included in ECDA regions, but the ECDA regions need not be contiguous.
    - FAQ-177 clarifies that an operator may initially define discreet ECDA regions that may be rolled up into a single region once the characteristics of the discreet regions are all shown to be the same.
- Operator's documentation should show they have:
    1. Evaluated their data on the pipeline,
    2. Specified criteria to identify their ECDA regions, and
    3. Each ECDA region identified contains:
        - Similar physical characteristics
        - Similar operating histories
        - Similar expected future corrosion conditions, and
        - The same indirect examination tools are used for that region.
- ECDA regions may be modified (separated or aggregated) during the ECDA process. This is usually based on:
    1. Unanticipated field conditions (drainage, soils, pavements)
    2. Tools not working as expected
    3. Different indirect examination tools used in region
    4. Conditions similar to other regions
- Operators' documentation should show that changes in regions are consistent with the region definition (similar characteristics and same tools used) and operator's region criteria.

D.02.e. Verify that the operator applies more restrictive criteria when conducting ECDA for the first time on a covered segment. [§192.925(b)(1)(i)]

D.02.e. Supplemental Guidance:

- Both §192.925(b)(1) and NACE RP0502-2002 require that more stringent requirements are to be used on initial ECDA's to provide an enhanced understanding of corrosion effects on pipeline integrity, including additional data collection, additional excavations, etc. Examples of more restrictive criteria include:
    - Pre-assessment
        - Making and/or segregating the covered segment into additional ECDA regions, which requires additional excavations
        - Perform test holes to obtain additional data on the pipeline and it's environment and soil conditions
        - Pre-marking the pipeline to enhance data integration such as putting flags or paint dots every 5' all along the pipeline
- Operators must document these more restrictive criteria. This documentation may consist of:
    - Operators can use two sets of requirements, one for the initial ECDA on a region or segment and the other for subsequent ECDA assessments on those regions or segments
    - Operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ECDA on a region or segment
    - Operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it (See feedback question and answer, Protocol D.05.d).
- FAQ-242 provides further guidance to operators on demonstrating that it used more restrictive criteria when conducting ECDA for the first time.

D.03 ECDA Indirect Examination

Verify that the ECDA Indirect Examination process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502-2002, 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. [§192.925(b)(2)]

D.03 *Supplemental Guidance:*

- 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.
- During the indirect inspection step, those coating faults or corrosion indications will 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 will be used to help establish priorities for excavation during step 3 of the ECDA process.
- For the initial ECDA on a region, operators must apply and document more restrictive criteria.
- NACE RP0502-2002, Section 3.4.1.3, allows an operator to substitute 100% direct (i.e., visual) examination for the indirect inspections and selected direct assessments that would otherwise be a part of ECDA. In such cases, NACE requires that the pre- and post-assessment steps must also be followed. If 100% inspection is used in this fashion, it meets NACE RP0502-2002 and is considered an application of ECDA. Such an exam would not be considered "other technology" and no notification is needed.

D.03.a. Verify that the operator **conducts indirect examination measurements** in accordance with NACE RP0502-2002, Section 4.2.

i. Verify that the operator identifies and clearly marks the boundaries of each ECDA region. [NACE RP0502-2002, Section 4.2.1]
ii. Verify that the operator performs indirect inspections over the entire lengths of each ECDA region and that the inspections conform to generally accepted industry practices. [NACE RP0502-2002, Section 4.2.2]
iii. Verify that the operator specifies and follows generally accepted industry practices for conducting ECDA indirect inspections and analyzing results. [NACE RP0502-2002, Section 4.2.2]
iv. Verify that the operator specifies 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 RP0502-2002, Section 4.2.3]

D.03.a. Supplemental Guidance:

- 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.
- To accomplish this, the NACE ECDA standard requires the operator to ensure that:
  - The entire ECDA region will be inspected by two indirect examination tools,
  - Each indirect tool inspection will be conducted and analyzed in accordance with accepted industry practices. (NACE RP0502-2002, Appendix A contains procedures for indirect survey tools.)
  - The indirect inspections will be conducted at spacing intervals close enough for a detailed assessment and so the inspection tool can detect and locate suspected corrosion activity on the region. (NACE RP0502-2002, Section 4.2.3)
  - Indication criteria and procedures are developed for taking readings so that the operator is able to locate coating faults regardless of corrosion activity at the fault. (NACE RP0502-2002, Section 4.3.1)
- In addition, the gas integrity rule requires the operator to document its procedures for using each tool, and the approach to be used for decreasing the physical spacing of tool readings when a defect is suspected.
- NACE defines an indication as "Any deviation from the norm as measured by an indirect inspection tool."
- Review the operator's documentation to verify the operator has:
  - Inspected the entire length of each ECDA region by two indirect examination tools. Note that NACE RP0502-2002, Section 4.2.1 suggests that operators should pre-mark each ECDA boundary;
    - FAQ-104 acknowledges that ASME B31.8S-2004 and the NACE standard differ on the need to examine 100% of each region with both tools, but that the more stringent NACE standard takes precedence.
  - Analyzed each inspection tool's data to ensure the assessment was effective, reliable and was conducted in conformance with industry practices;
  - Developed procedures that have specified physical spacing of readings and practices to be followed in defect areas. GTI PIM ECDA Protocol Table 4.4.2 below suggests spacing of indirect tool readings.

GTI PIM ECDA Protocol Table 4.4.2 - Recommended Interval Spacing and Measurement Units

TOOL	RECOMMENDED INTERVAL SPACING FT)	RECOMMENDED MEASUREMENT UNITS
CIS (impressed current system)	3 to 10	mV (CSE)
CIS (constant current / sac. anodes)	3 to 10	mV (CSE)
DCVG	3 to 6	%IR cathodic/anodic
PEARSON (ACVG)	15 to 25	% of total signal
PCM[1] (EM, AC Attenuation)	Maximum depends on conditions Narrowed Down 60-150 Min 10-15 (note 5)	loss (% drop) in signal[4] current (mA) vs. distance may also be plotted in dBmA vs. distance (note 5)
PCM A-Frame (ACVG)	Maximum depends on conditions, Narrowed Down 2-4, Min < 1 (note 5)	dBuV
C-Scan[1] (EM, AC Attenuation)	Maximum depends on conditions, Narrowed Down 60-150, Min 10-15 (note 5)	loss (% drop) in signal[4] current (mA) vs. distance, may also be plotted in mB/ft attenuation (note 5)
Cell-To-Cell	10 to 20	mV shift: reverse in polarity [2]
4-Pin Resistivity[3] (or soil box if 4-pin not appropriate)	Start, Finish, 1/3, 2/3 distance along region length	ohm-cm

Notes:

1. AC attenuation is performed in a continuous manner over the line, varying the distance from transmitter to receiver (usually start at least 25 ft from transmitter).
2. Soil resistivity effects sensitivity.
3. 4-Pin resistivity is not an indirect inspection tool, but will be required for this program.
4. Relative to immediate adjacent plateaus.
5. See manufacturer operations manuals for more details and special circumstances.

D.03.b. Verify that the operator properly aligns indications and compares the data from each indirect examination to characterize both the severity of indications and urgency for direct examination in accordance with NACE RP0502-2002, Section 4.3 and NACE RP0502-2002, Section 5.2.

i. Verify the operator specifies criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum criteria include
   1. Known sensitivities of assessment tools
   2. The procedures for using each tool
   3. The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected. [§192.925(b)(2)(ii) and NACE RP0502-2002, Section 4.3.1.1]

ii. Verify that the operator specifies and applies criteria for classification of the severity of each indication. [NACE RP0502-2002, Section 4.3.2],

   1. Verify that the operator considers the impact of spatial errors when aligning indirect examination results. [NACE RP0502-2002, Section 4.3.1.2]
   2. Verify that the operator compares the results from the indirect inspections and determines the consistency of indirect inspections results to resolve conflicting or differing indications by the primary and secondary tools. [NACE RP0502-2002, Section 4.3.3]

3. Verify that the operator compares indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA Region definitions. [NACE RP0502-2002, Section 4.3.4]

iii. Verify that the operator specified and applies criteria for defining the urgency level (i.e., immediate, scheduled, or monitored) with which excavation and direct examination of indications will be conducted based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion. [§192.925(b)(2)(iii) and (iv) and NACE RP0502-2002, Section 5.2]

iv. Verify that the operator's ECDA procedures have a process to address pipeline coating indications. The procedures must provide for integrating ECDA data with encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage, and to address this threat as required by §192.917(e)(1) (See Protocol C.02 and Protocol C.03). [§192.917(b), §192.917(e) and §192.925(b)]

D.03.b. Supplemental Guidance:

- The purpose of aligning and comparing indications is to ensure data from both indirect examination tools identify indications consistently, and results agree with pre-assessment expectations and corrosion history. Indications are to be classified as to their severity and prioritized for excavation. To accomplish this operators must have documentation to verify it has:
  - Analyzed the indication data documented during the indirect examinations;
  - Aligned and compared the results of the tool runs;
  - Resolved spatial errors;
  - Addressed data inconsistencies;
  - Identified those potential defects for severity classification and excavation prioritization;
  - Identified severity criteria for each indication taking into account capabilities of indirect inspection tool, unique conditions within the ECDA region, whether corrosion is active at the location, and expertise level of personnel analyzing the inspection data, GTI PIM ECDA Protocol Table 4.6.2 below contains suggested severity criteria;
  - Conducted a feasibility check by comparing results of indirect survey tools with pre-assessment results and prior history;
  - Specified criteria for identifying those indications that must be considered for excavation based on likelihood of current corrosion activity, along with the extent and severity of prior corrosion;
  - Assigned excavation priorities to each of the indications identified during the indirect examinations. GTI PIM ECDA Protocol Table 5.3.5 below contains suggested priorities.
- Activities in the ECDA process as called for in the NACE standard use terminology that is close to that used in the rule for remediation. However, the activities are different. After an operator has aligned and integrated data in the Indirect Examination phase of ECDA, the severity of the indications must be classified in one of three categories: "Severe", "Moderate", or "Minor". Once so categorized, the operator must then establish a priority for excavating the indications, by placing them in the following categories: "Immediate", "Scheduled", or "Monitored". It must be emphasized that this is ONLY a categorization for prioritization of direct examination. The operator is still in the discovery process when this categorization is performed. As excavation is being done, the operator's discovery process will come to an end as the operator can now directly determine the nature and extent of the anomaly. The anomaly, once directly inspected, will then be placed in the categories established in §192.933 for remediation/repair. These categories are "Immediate", "One-Year", and "Monitored" and describe when remediation activities must be performed to address the anomaly. Therefore, while similar in terms used, one set of categories describes the priority for excavating indications and the other set of categories describes the remediation priority for anomalies once discovery has been declared.
  - FAQ-213 clarifies that after each indication has been categorized according to its severity, the operator is responsible for determining the urgency (prioritization) of excavation of indications for direct examination. Identified defects then must be scheduled for remediation or classified as "immediate", "one-year", and "monitored" repair conditions.

- The activities of the Indirect Examination phase of ECDA are part of the baseline assessment and re-assessment processes that are required in §192.921 and §192.937. "Discovery" of conditions that must be remediated in accordance with §192.933 is usually not achievable until excavation is performed in the Direct Examination phase. Completion of the Indirect Examination activities must be followed shortly by the Direct Examination (excavation) activities although this timeframe between the two phases is not explicitly provided in the Rule or in the standards.
    - FAQ-58 clarifies that discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline.
    - FAQ-232 addresses timeframes that apply to discovery of defects when using Direct Assessment.
- Operators must follow the guidelines and procedures that they have instituted in their DA and ECDA plans. As an example, during a recent inspection an operator had an indication that had less than the 100 mV shift on a pipeline and the integration with encroachment data showed a large water main crossing above the pipeline. Based on these two facts and the operators procedures, this indication should have been classified as "severe" (low CP levels and potential TPD). Based on a severe classification, the indication should have been given a priority of "immediate" and thus should have been excavated. The indication was not excavated and its priority was reduced to "monitor." The rationale the operator gave was that the water main was installed before the pipeline and thus there "should" be no TPD. However, such evaluations ignore other potential damage scenarios, such as damage to the coating on the transmission line when it was inserted under the water main. In addition the operator stated that the pipeline was very deep and it would be very expensive to excavate it and it had no record of corrosion problems on the pipeline in this area. None of these reasons justify downgrading the indication, especially since this was the initial ECDA on this region and (per NACE) operators are not allowed to downgrade indications (NACE RP 0502 §5.9.1.2) when applying ECDA for the first time. Furthermore, because of the poor CP on this pipeline, the operator should use the default corrosion rate of 16 mils per year unless they can provide a technical justification for a lower rate.
- ECDA procedures must address situations when the ECDA indicates pipeline coating damage, because coating damage could also be an indicator of third party damage. It would be expected that procedures should also address the potential threat to coatings due to outside force damage.
- Indications of coating damage data must be integrated with:
    - Operational and/or incident data
    - Encroachment data (records)
    - Data showing the location of foreign structures that cross the pipeline or are located nearby, and
    - Data from one call notifications
- The process should:
    - Include an investigative approach to identifying locations that could have third party damage defects.
    - Utilize conservative criteria for determining the need to excavate and directly examine locations suspected of possible third party damage.
- Refer to Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage.
- FAQ-218 clarifies that the rule addresses the threat of third party damage in two ways. First, the threat of a future third party damage event is expected to be present in covered segments. Therefore, prevention of future events is addressed under the requirements for preventive and mitigative actions. Second, if, as part of a baseline assessment or reassessment, the operator has gathered data from an ECDA or internal inspection tool survey, then he must take further action to look for third party damage events that did not result in immediate failure, but may have resulted in residual damage that could fail in the future..
- The pipeline operator must utilize appropriate methods such as ASME B31.4, ASME B31.8, and API 1160 to address risks other than external corrosion - see NACE RP0502-2002, Section 5.1.5.

GTI PIM ECDA Protocol Table 4.6.2 - Severity of Measurement Amplitude Classification Table

Tool	**Severity of Measurement Amplitude Change of Indication (In Units of Measurement Resolution see Table 4.4.2)**		
	MINOR	**MODERATE**	**SEVERE**
CIS[1] (impressed current system)	Small Dips, on & off potentials both are more negative than -0.850 V	Medium Dips, on potential more negative than -0.850 V off potential not more negative than -0.850 V	Large Dips, on & off potentials, both not more negative than -0.850 V
CIS[1] (constant current / sac. anodes) on-reads	Small Dips, more negative than -0.850 V	Medium Dips, not more negative than -0.850 V	Large Dips, not more negative than -0.850 V
DCVG	1-35% cathodic both on & off	35-50% cathodic on, anodic or neutral off	50-100% anodic both on & off
PEARSON (ACVG)	1-30%	30-65%	65-100%
PCM[1] (EM, AC Atten.)	1-30%	30-50%	50-100%
PCM A-Frame (ACVG)	30-50 dBuV	50-70 dBuV	> 70 dBuV (2 ft intervals around defect)
C-Scan (EM, AC Atten.)	10-25%	25-60%	60-100%
Cell-To-Cell (with soil resistivity)	5000 ohm-cm)	>10 mV & (3000-5000 ohm-cm)	>10 mV & (3000 ohm-cm)
4-Pin Resistivity	>10,000 ohm-cm	1000-10,000 ohm-cm	<1000 ohm-cm

Note 1 - Level of dips depends on conditions peculiar to the pipeline region under study.

GTI PIM ECDA Protocol Table 5.3.5 - Prioritization of Indirect Inspection Indications

IMMEDIATE ACTION	**SCHEDULED ACTION**	**SUITABLE FOR MONITORING**
Individual severe indications that are classified as severe by more than one indirect inspection technique.	All remaining severe indications that were not placed in an immediate action category.	All remaining indications.
Individual severe indications in regions of moderate prior corrosion.	All remaining moderate indications in regions of significant prior corrosion.	
Individual severe indications where the likelihood of ongoing corrosion activity cannot be determined.	Groups of minor indications in regions of severe prior corrosion.	
Multiple severe indications in close proximity		
Moderate indications in regions of severe prior corrosion.		
Groups of moderate indications in regions of moderate prior corrosion.		
Any severe or moderate indications if significant prior corrosion is suspected.		
For initial ECDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results.		

D.03.c. Verify that the operator applies more restrictive criteria when conducting ECDA for the first time on a covered segment. [§192.925(b)(2)(i)]

D.03.c. Supplemental Guidance:

- Both §192.925(b)(2) and NACE RP0502-2002 require that more stringent requirements are to be used on initial ECDA's to provide an enhanced understanding of corrosion effects on pipeline integrity, including additional data collection, additional excavations, etc. Examples of more restrictive criteria include:
    - Indirect Inspections
        - For paved areas, require boring to the subsurface soil to obtain readings
        - Use an additional tool, three instead of two, four instead of three, etc.
        - Establishing a severity table and apply increased severity for each tool result:
            1. For CIS any reading more positive than -0.95 vDC is a severe indication (even though the CP potential shows that the area currently has adequate CP).
            2. For PCM the severe category is a 15% drop in signal within 1000', or 20% drop in 2000'. (Normally a 20% signal loss in PCM over 1000' would be severe).
        - Require closer distance between test point readings for possible greater accuracy and less chance of missing an indication
        - Increase the excavation priorities by categorizing the highest two coating fault indications be treated as immediate and all subsequent indications be scheduled no matter how minor they appear.
        - Compare readings and results with all history and if even if not a close match, make the indication more severe
        - For indirect survey tool conflicts, even if resolved, redo indirect inspections for all tools.
- Operators must document these more restrictive criteria. This documentation may consist of:
    - Operators can use two sets of requirements, one for the initial ECDA on a region or segment and the other for subsequent ECDA assessments on those regions or segments
    - Operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ECDA on a region or segment
    - Operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it (See feedback question and answer, Protocol D.05.d).
- FAQ-242 provides further guidance to operators on demonstrating that it used more restrictive criteria when conducting ECDA for the first time.

D.04 ECDA Direct Examination

Verify that the ECDA Direct Examination process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502-2002, Section 5 to collect data to assess corrosion activity and remediate defects discovered. [NACE RP0502-2002, Section 5.1.1 and §192.925(b)(3)]

D.04 *Supplemental Guidance:*

- Direct examination is the third step in the ECDA process. The objectives of the NACE RP0502-2002, Section 5.1.6, direct examination step are to:
    - Excavate defects at locations most susceptible to corrosion activity to:
        1. Determine which indications from the indirect inspections are most severe and,
        2. Collect data to assess corrosion activity, including determining size of the largest remaining defect, corrosion growth rate, and remaining strength,
    - Determine root causes, remediate defects and corrosion conditions, and

    - Conduct an in-process evaluation which includes:
        1. Assessing severity classifications, and
        2. Assessing excavation priorities.
- For the initial ECDA on a region, operators must apply and document more restrictive criteria
- NACE RP0502-2002, Section 3.4.1.3, allows an operator to substitute 100% direct (i.e., visual) examination for the indirect inspections and selected direct assessments that would otherwise be a part of ECDA. In such cases, NACE requires that the pre- and post-assessment steps must also be followed. If 100% inspection is used in this fashion, it meets NACE RP0502-2002 and is considered an application of ECDA. Such an exam would not be considered "other technology" and no notification is needed.
- FAQ-196 states that the provisions of NACE RP0502-2002, which is incorporated into the rule by reference, govern the use of ECDA. The recommended practice does not specify any time limit between step 2, Indirect Inspection, and step 3, Direct Examination.

D.04.a. Verify that the operator performs excavations and data collection in accordance with NACE RP0502-2002, Section 5.3, NACE RP0502-2002, Section 5.4, NACE RP0502-2002, Section 5.10 and NACE RP0502-2002, Section 6.4.2.

i. Verify that the operator makes excavations based on priority categories described in NACE RP0502-2002, Section 5.2. [NACE RP0502-2002, Section 5.3.1]
ii. Verify that the operator identifies and implements minimum requirements for data collection, measurements, and recordkeeping, to evaluate coating condition and significant corrosion defects at each excavation location. [NACE RP0502-2002, Section 5.3, NACE RP0502-2002, Section 5.4, NACE RP0502-2002, Appendix A, NACE RP0502-2002, Appendix B, and NACE RP0502-2002, Appendix C]
iii. Verify that the number and location of direct examinations complies with NACE RP0502-2002, Section 5.10 and NACE RP0502-2002, Section 6.4.2

D.04.a. Supplemental Guidance:

- Refer to Supplemental Guidance Appendix D.02, External Corrosion Direct Assessment Excavation Location Selection, which is a flow diagram depicting the ECDA excavation location selection process.
- Documentation should be evaluated to verify:
    - ECDA procedures contain criteria for scheduling excavations (§192.925(b)(2)(iv)),
    - Excavations of indications were performed based on priority categories (NACE RP0502-2002, Section 5.2.1),
    - ECDA procedures contain requirements for data collection, measurements and record keeping to evaluate coating condition, significant corrosion defects for both regions and for excavation of indications, and
    - Number and Type of direct examinations complies with NACE RP0502-2002, Section 5.10 and NACE RP0502-2002, Section 6.4.2.
    - Refer to GTI PIM ECDA Protocol Table 5.3.5 in the Supplemental Guidance for Protocol D.03.b for examples of criteria for prioritizing excavations of indications.
- At least two excavations must occur in each ECDA region containing HCA segments when conducting the DA process for the first time. Casings present a special problem for ECDA methods in that two complementary indirect examination tools do not appear to be available. ECDA therefore may not be a valid assessment method for casings. Should this issue be resolved such that ECDA can be used for casings, the process as prescribed in the NACE standard requires direct examination of casings (two for first-time application), even if no indications are present. Currently, some operators are notifying PHMSA that they will be a using guided wave UT tool to assess cased crossings under the "other technology" section of §192.921(a)(4) and §192.949.
- Excavations are required for two portions of the ECDA process.

    - The first is the direct examination step, step 3 in NACE RP0502-2002. In that step, all immediate indications must be excavated. For the scheduled indications, the standard requires that the most severe indication in each region be excavated, and that the two most severe indications in each region must be excavated if it is the first time ECDA has been used for that pipeline. In this case, the extra examinations are on a "per region" basis.
        - [Note: Other special cases are addressed in the NACE standard, such as what to do when a scheduled indication has corrosion metal loss of 20% WT (or greater), or what to do when there are no immediate or scheduled indications. Refer to Supplemental Guidance Appendix D.02, External Corrosion Direct Assessment Excavation Location Selection, which is a flow diagram depicting the ECDA excavation location selection process, and covers all circumstances addressed in NACE RP0502-2002.]
    - The second step requiring excavations is the post-assessment step, step 4 in NACE RP0502-2002. NACE RP0502-2002, Section 6.4.2 requires at least one additional random excavation (two additional random excavations for initial ECDA applications). Here, the requirement is for one (or two) additional excavations per segment.
    - The major area of confusion appears to be in the use of validation excavations in Step 4 to determine the effectiveness of the ECDA process, which is performed on a SEGMENT.
    - FAQ-203, which states that provisions in NACE RP0502-2002 requiring additional actions "when ECDA is applied for the first time" apply to the first application of ECDA in each Region containing covered segment(s).
- Excavation of an indication will enable the operator to declare ‘discovery’ of a condition when one exists and to classify those anomalies as immediate repair conditions, one-year repair conditions, monitored conditions, or otherwise schedule repair in accordance with ASME B31.8S-2004, Section 7, Table 4. It would be reasonable to expect the operator to proceed to repair any condition discovered that is classified as other than a "monitored" condition, although the Rule would permit the operator to wait to repair those not classified as "immediate".
- The Rule requires completion of the evaluation of assessment results within 180 days of termination of the assessment activity. However, when conducting DA, assessment isn't actually complete until the direct examination process is complete (i.e., the last excavation is performed). Since the operator will have sufficient information to declare discovery of any anomalies as each indication is excavated, the application of the 180-day time limit of the Rule is moot. Further, the Rule and the standards do not address the time lag between completion of the indirect examination phase and the direct examination phase of the DA process.
    - FAQ-232 addresses timeframes that apply to discovery of defects when using Direct Assessment.
    - PHMSA expects all required direct examinations to be complete within 4-6 months of completion of the indirect examination process. The basis for it taking longer than this to complete direct examinations should be documented and appropriate actions taken to protect the integrity of the pipeline.

D.04.b. Verify that the operator determines the remaining strength at locations where corrosion defects are found. Any corrosion defects discovered during direct examinations must be remediated in accordance with §192.933. [§192.925(b)(3)(ii), §192.933, and NACE RP0502-2002, Section 5.5]

D.04.b. Supplemental Guidance:

- The gas integrity rule and NACE RP0502-2002, Section 5.5 requires the pipeline operator to evaluate the remaining strength at locations of corrosion defects. (RSTRENG, ASME B31G most common methods)
- The gas integrity rule requires the operator’s procedures include criteria for deciding what action needs to be taken when:

    - Corrosion defects exceed allowable limits (NACE RP0502-2002, Section 5.5.2.2), for example other defects should be assumed to be present elsewhere in the region which need to be addressed, and
    - Root cause reveals conditions for which ECDA is not suitable (NACE RP0502-2002, Section 5.6.2) e.g., Shielding by Disbondment, or Biological Corrosion MIC, etc. (Root causes for which ECDA may not be suitable will need to be evaluated by alternative methods.)
- Operators' documentation and procedures must specify:
    - The method to calculate remaining strength at defect locations (such as ASME B31G or RSTRENG),
    - The criteria for actions to be taken if corrosion defects exceed allowable limits, and
    - The criteria for deciding what actions should be taken when root cause analysis reveals conditions for which ECDA is not suitable.
- Refer to NACE RP0502-2002, Appendix C for information concerning coating damage and corrosion depth measurements.

D.04.c. Verify that the operator identifies the root cause of all significant corrosion activity, [NACE RP0502-2002, Section 5.6] and identifies and reevaluates all other indications that occur in the pipeline segment where similar root-cause conditions exist. [NACE RP0502-2002, Section 5.9.3]

i. Verify that the operator considers alternative methods of assessing the integrity of the pipeline segment if the operator's root cause analysis uncovers problems for which ECDA is not well suited. [NACE RP0502-2002, Section 5.6.2 and §192.925(b)(3)(ii)(b)]

D.04.c. Supplemental Guidance:

- NACE RP0502-2002, Section 5.6 and NACE RP0502-2002, Section 5.7 require the pipeline operator to:
    - Identify a root cause for all significant corrosion activity.
    - Implement remediation activities to mitigate or preclude future corrosion.
    - Re-evaluate all other indications where similar root causes exist (See NACE RP0502-2002, Section 5.9.3).
- Root causes may include inadequate CP current, previously unidentified sources of interference, etc.
- Operators' documentation and procedures must ensure:
    - Procedures address requirements to perform root cause analyses on all significant corrosion activity,
    - Root cause analyses have been performed.

D.04.d. Verify that the operator mitigates or precludes future external corrosion resulting from significant root causes. [NACE RP0502-2002, Section 5.7]

D.04.d. Supplemental Guidance:

- NACE RP0502-2002, Section 5.6 and NACE RP0502-2002, Section 5.7 require the pipeline operator to:
    - Identify a root cause for all significant corrosion activity.
    - Implement remediation activities to mitigate or preclude future corrosion.
    - Re-evaluate all other indications where similar root causes exist. NACE RP0502-2002, Section 5.9.3.
- Root causes identified must be addressed and remediated to ensure the integrity of the pipeline.
- Operators' documentation must ensure significant root causes have been mitigated to preclude future corrosion.

D.04.e. Verify that the operator performs an evaluation of the indirect inspection data, the results from the remaining strength evaluation and root cause analysis to evaluate the criteria and assumptions used to: [NACE RP0502-2002, Section 5.7, NACE RP0502-2002, Section 5.8 and §192.933]

i. Categorize the need for repairs
ii. Classify the severity of individual indications

D.04.e. Supplemental Guidance:

- NACE RP0502-2002, Section 5.8 requires the operator to perform an in-process evaluation of the:
  - Indirect inspection data,
  - Results from the remaining strength evaluation, and
  - Root cause analyses.
- The purpose of the in-process evaluation is to determine whether the following need changing:
  - Excavation priority ranking criteria,
  - Classification criteria for indication severity, and
  - The actual excavation priority rank or severity classification of indications evaluated to that point.
- For example, when existing corrosion is more severe than prioritized, the operator shall modify the criteria and reprioritize all affected indications.
- If repeated direct examinations indicate corrosion activity is worse than indicated by the indirect inspection data, the feasibility of using ECDA needs to be re-evaluated.
- The operator's IM program documentation must contain requirements for the performance of an in-process evaluation that include analysis of the types of information and the need for criteria changes and/or actual indication re-categorization described above.
- FAQ-130 clarifies that PHMSA does not have to be notified of the changes to criteria or indication re-categorization as a result of the in-process evaluation.

D.04.f. As appropriate, verify the basis upon which the operator may reclassify and reprioritize indications in accordance with any of the provisions that are specified in NACE RP0502-2002, Section 5.9. [§192.925(b)(3)(iv)]

D.04.f. Supplemental Guidance:

- The gas integrity rule requires each operator's procedures include criteria that describes how and on what basis an operator will :
  - make changes to its criteria for classifying severity and establishing priorities for indications,
  - Changes in the classification or priority of indications.
- Operators' documentation must ensure its procedures address the bases for changes to its criteria and to indications' severity classification and priority for excavation.
- For an initial ECDA on a region, operators cannot reduce the urgency of indications [NACE RP0502-2002, Section 5.9.1.2]

D.04.g. Verify the operator establishes and implements criteria and internal 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. [§192.925(b)(3)(iii), §192.909, and §192.911(k)]

D.04.g. Supplemental Guidance:

- The gas integrity rule requires each operator's procedures include criteria that describes how and on what basis an operator will:
  - Provide internal notifications for any changes in the ECDA Plan that affect the severity classification, priority of direct examination, and time frame for direct examination of indications.
    - FAQ-130 clarifies that PHMSA need not be notified unless the changes substantially affect the total IM program's implementation or significantly modify an operator's overall IM program or the schedule for carrying out program elements.

D.04.h. Verify that the operator has a process to consider the use of assessment methods other than ECDA (i.e., ILI or Subpart J pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage and stress corrosion cracking) discovered during direct examination. [NACE RP0502-2002, Section 5.1.5 and §192.933]

D.04.h. Supplemental Guidance:

- NACE RP0502-2002, Section 5.1.5 requires the operator to have a process to address conditions other than external corrosion found during the ECDA process. The gas integrity rule identifies other methods such as In-Line Inspection or hydrostatic pressure testing as being required to address conditions such as mechanical damage, stress corrosion cracking, etc.

D.04.i. Verify that the operator applies more restrictive criteria when conducting ECDA for the first time on a covered segment. [§192.925(b)(3)(i)]

D.04.i. Supplemental Guidance:

- Both §192.925(b)(3) and NACE RP0502-2002 require that more stringent requirements are to be used on initial ECDA's to provide an enhanced understanding of corrosion effects on pipeline integrity, including additional data collection, additional excavations, etc. Examples of more restrictive criteria include:
  - Direct Examination
    - Provide a larger excavation to assure all nearby indications are discovered to eliminate the potential of major indications masking minor or less severe indications
    - Requiring additional testing and or NDE results be obtained before closing excavations (such as Magnetic particle, X-ray and UT readings on all suspected indications, seams and welds)
    - Based on what is discovered in the initial direct examination, increase the urgency of all remaining indications.
    - Increase the urgency of repair criteria to repair/replace non critical defects
    - Examine areas that in the past have been problematic regardless of current indications (additional excavations required)
    - Implement root cause fix on all pipelines that could be affected, not just locations that are similar
    - Resurvey ECDA region after immediate indications are repaired to determine if other indications were masked by large indication.

        - Include an investigative approach to identifying and excavate locations that could have third party damage defects.
- Operators must document these more restrictive criteria. This documentation may consist of:
    - Operators can use two sets of requirements, one for the initial ECDA on a region or segment and the other for subsequent ECDA assessments on those regions or segments
    - Operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ECDA on a region or segment
    - Operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it (See feedback question and answer, Protocol D.05.d).
- FAQ-242 provides further guidance to operators on demonstrating that it used more restrictive criteria when conducting ECDA for the first time.

D.05 ECDA Post-Assessment

Verify that the ECDA Post assessment process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502-2002, Section 6, to (1) define reassessment intervals and (2) assess the overall effectiveness of the ECDA process. [§192.925(b)(4) and §192.939]

D.05 *Supplemental Guidance:*

- Key issues addressed during the Post Assessment step include:
    - Calculation of remaining life of each ECDA region,
    - Determining reassessment intervals,
    - Identifying performance measures,
    - Validating the ECDA process, and
    - Feedback and continuous improvement process

D.05.a. Verify that the operator determined **reassessment intervals** in accordance with NACE RP0502-2002, Section 6.

i. Verify the adequacy of the operators remaining life calculations. [NACE RP0502-2002, Section 6.2]
ii. Verify that the maximum re-assessment intervals for each region are one half the calculated remaining life. [NACE RP0502-2002, Section 6.1.3 and NACE RP0502-2002, Section 6.3]

D.05.a. Supplemental Guidance:

- The operator's documentation should demonstrate:
    - Remaining life calculations are based on applying the value for the maximum flaw size as the most severe indication excavated, and
    - Corrosion growth rate is based on measured corrosion rate data applicable to the region or applying the default value of 16 mils per year contained in NACE RP0502-2002, Appendix D, Section D3.2.
- Refer to NACE RP0502-2002, Appendix D, Section D3.2 for default corrosion growth rate. It is conservative at 16 mils/year; a routine value of 6-7 mils per year has been used by a number of operators. The appendix states the 16 mils per year value may be reduced 25% to a value of 12 mils per year if the corrosion protection has been good.
- Refer to Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval, for information and an example of using the remaining life formula and determining re-assessment intervals.
    - Note: The formula for Safety Margin (SM) found in the original published version of NACE RP0502-2002, was in error. NACE issued an erratum to correct the formula. Refer

to the above referenced appendix and example for the corrected formula. The correct formula is SM = Failure Pressure Ratio - MAOP Ratio (dimensionless).

- NACE requires that the reassessment interval be determined based on the largest defect found during direct examinations. Therefore, if an operator performs the minimum number of excavations, and finds an immediate condition, then the reassessment interval would be zero. In this case an operator would be expected to take certain actions in response to the immediate condition. In addition, the operator would have some (limited) alternatives for determining the next reassessment, in response to the immediate condition. One possibility might be to immediately perform an assessment using ILI or pressure test. This would be the preferred alternative whenever feasible.

  Another possibility might be to excavate all indications. If no other immediate conditions were found, the operator might (depending on what was found during the excavations) be able to conclude (based on root cause analysis) that the immediate condition was unique, in which case the reassessment interval can be based on the next largest defect discovered (Re: NACE RP0502, section 6.2.2.1). In the case where the operator excavates all indications, but the root cause of the immediate condition is not unique, the operator may be able to perform a more sophisticated or statistical analysis which would allow a different assumed defect size for the remaining life calculation (Re: NACE RP0502, section 6.2.2.2). The analysis and justification for using any defect size, other than the largest defect found during direct examinations, must be documented and will be subject to inspection and must meet the expectations specified in NACE RP0502 Sections 6.2.2.

  However one determines the maximum remaining flaw size for the remaining life calculation, the method to calculate the reassessment interval must be the one specified in NACE RP0502. The key is to perform enough excavations, and perform enough engineering analysis of as-found conditions, to establish an appropriate and technically defensible size of remaining defect which must be assumed in the remaining life calculation.

D.05.b. Verify that the reassessment intervals are adjusted if required in accordance with special provisions in Subpart O, as follows:

i. Verify that reassessment intervals do not exceed the maximum intervals (refer to Protocol F) established in §192.939, as follows:
   1. 10 years for pipeline segments operating at SMYS levels greater than 50%
   2. 15 years for those segments operating between 30 and 50% SMYS
   3. 20 years for those segments operating below 30% SMYS

ii. Verify that the operator specifies and applies 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. [§192.925(b)(4)(ii)]

D.05.b. Supplemental Guidance:

- Maximum reassessment intervals may not exceed the values established in §192.939, i.e., re-assessment intervals must not exceed:
  - 10 years if above 50% SMYS,
  - 15 years if between 30 and 50% SMYS,
  - 20 years if below 30% SMYS,
  - Conditions may warrant shorter intervals.
- The gas integrity rule also requires operators procedures contain criteria for evaluating whether any conditions found during direct examinations in each ECDA region indicate a need for a reassessment interval less than that specified in §192.939.
- Operators documentation should verify that:

    - The half life concept is being applied to remaining life calculations,
    - The value for reassessment intervals provided in §192.939 are not exceeded for the level of SMYS the ECDA region operates.
    - Operators limit reassessment intervals if direct exams have discovered conditions warranting more frequent reassessment intervals than §192.939.
- FAQ-197 clarifies there is no specific limit on when an operator must reassess if something is learned in the post assessment step that may change the results in another ECDA. Invalid results, however, can call into question whether an assessment was actually completed. Thus, operators may want to perform reassessment before the original reassessment interval expires, if still possible. In any event, PHMSA would expect operators to respond in a time frame that is commensurate with the importance of the potential problem that is identified.

D.05.c. Verify that performance measures for ECDA effectiveness have been defined and are monitored. [§192.925, §192.945(b) and NACE RP0502-2002, Section 6]

i. Verify that at least one additional, randomly selected anomaly location has been excavated for process validation. [NACE RP0502-2002, Section 6.4.2]
ii. Verify that additional criteria have been established and monitored to evaluate long-term program effectiveness such as those identified in NACE RP0502-2002, Section 6.4.3. [§192.945(b) and NACE RP0502-2002, Section 6.4.3]

D.05.c. Supplemental Guidance:

- Documentation should verify that operators have established post assessment process effectiveness procedures (process validation checks)which require:
    - An additional randomly selected direct examination of each ECDA region,
        - Two additional digs for first time applications of ECDA on a region,
        - One direct exam at a "scheduled" indication, and
        - One direct exam where no indication was detected.
    - Actions to be taken by the operator if conditions are more severe, for example if conditions found during validation digs result in re-assessment intervals scheduled sooner than ECDA process had determined, then this might require:
    - Reevaluation & Repeating the ECDA Process, or
    - Using a Different Assessment Method other than ECDA.
- The second part of assessing the effectiveness of the ECDA process involves identifying criteria to measure and monitor the ECDA performance.
- The gas integrity rule requires that each operator develop post assessment procedures to identify measures for evaluating the long-term effectiveness of the ECDA process in addressing external corrosion. (§192.925(b)(4)(i))
- NACE RP0502-2002 also requires the operator to establish criteria for assessing long term effectiveness of the ECDA process, and suggests:
    - Reliability or repeatability of process measures such as the number of reclassifications and repriorizations (to evaluate severity and priority criteria).
    - Frequency at which immediate or scheduled indications arise (whether corrosion is being managed effectively demonstrating improvement in the integrity of the pipeline).
- Documentation should verify that the operator has:
    - Procedures for addressing long term effectiveness of ECDA process
    - Identified criteria to measure performance
- The ASME B31.8S-2004, Appendix A performance measures follow:
    - Number of repair actions taken due to direct assessment results, immediate and scheduled
    - Number of external corrosion leaks (for low stress pipelines it may be practical to report these by leak classification).

D.05.d. Verify the operator's process has incorporated feedback at all appropriate opportunities throughout the ECDA process to demonstrate feedback and continuous improvement. [§192.907(a) and NACE RP0502-2002, Section 6.5]

D.05.d. Supplemental Guidance:

- NACE RP0502-2002 requires the operator to improve the ECDA applications by incorporating feedback throughout the ECDA processes as well as during scheduled activities and reassessments. (NACE RP0502-2002, Section 6.5)
- Operators should address the following in its feedback processes:
    - In the Indirect Inspection Step operators should provide feedback on how well classifications matched with actual results in the direct examination step. Examples may include:
        - How well indirect inspect tools performed and if there was a need to use additional tools to eliminate conflicts between tools.
        - Determination of which tools performed the best in certain coatings and soil conditions and to mandate their use in similar circumstances.
        - Changing some of the specific ranges for the severe, moderate and minor classifications for indirect inspection tools.
    - In the Direct Examination Step operators should provide feedback on what information collected was useful. An example would be if visual coating inspections were adequate or that a holiday detector should be used to determine if the coating was porous and somewhat disbonded.
    - In the Direct Examination Step operators should provide feedback on the remaining strength of corrosion anomalies evaluated. Examples may include:
        - Integrating the indirect inspection results with the direct examination results and overlaying environmental (soil conditions) and cathodic protection history. This could yield additional information on problems that may be more systemic than previously believed.
        - Integrating MIC results with coating damage and other issues such as stray DC current conditions that could yield more severe conditions than with MIC.
    - In the Direct Examination Step operators should provide feedback on the root cause of corrosion anomalies evaluated.
        - If the root cause of the anomaly was a systemic problem, such as coating degradation, the operator should be looking for similar conditions elsewhere on all pipelines of a similar age and coating type.
        - If the problem was isolated, the operator would not need to look at other locations and this should be documented.
        - If the root cause was shown to be the result of an issue that ECDA is not well suited, such as shielding, the operator should be using other assessment methods on all pipelines with similar characteristics.
    - In the Direct Examination Step operators should provide feedback on remediation activities. Examples may include:
        - If the coating on a segment were failing and the pipeline was recoated, then feedback to the pre-assessment step should be made to possibly change the tools selected and modify the age of the coating.
        - If the area had low CP potentials and an additional rectifier was added, new CP potentials should be obtained to document that the remediation was producing acceptable CP potentials in the area of concern.
    - In the Direct Examination Step operators should provide feedback on the in-process evaluations. The integration of indirect inspection results with direct examination findings and remaining strength calculations should provide operators with feedback to adjust the severity classification of indirect inspection indications. On an initial ECDA no reduction in the severity classifications is allowed.

  - In the Post Assessment Step operators should provide feedback on the Direct Examination of validation locations. Based on the findings and the outcomes of actual vs. the predicted examinations in the validation step, operators should have additional information on where anomalies are located and where no indications are present.
  - Feedback has been documented, evaluated and acted upon.

D.06 Dry Gas ICDA Programmatic Requirements

If the operator elects to use ICDA, verify that the operator develops and implements an ICDA plan in accordance with §192.927.

D.06 *Supplemental Guidance:*

- When an operator determines that they will use ICDA they must prepare and follow an ICDA plan. This plan must meet all of the requirements of §192.927 and all of the relevant sections of ASME B31.8S-2004 (mainly Sections 6.4 and Appendix B2).
- FAQ-155 notes that ASME Appendices that are referenced in the rule automatically become mandatory.
- FAQ-193 addresses the issue that a standard had not initially been approved for ICDA. Operators must use both the rule, §192.927 and ASME B31.8S-2004 as guides for performing the ICDA process. Additionally the recently issued standard, NACE SP0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas, may also be utilized as long as the requirements in §192 and ASME B31.8S-2004 are also addressed.
- Supplemental Guidance Appendix C.03, White Paper, "Look Beyond" Provisions, provides discussion on the need for an operator to include consideration of ICDA actions on non-covered segments.

D.06.a. Verify that the operator developed a documented ICDA plan [§192.927(c)]

D.06.a. Supplemental Guidance:

- An operator must have developed an approved written plan to use DG-ICDA on covered pipeline segments.
  - If the operator is not actively engaged in implementing DA, then the DA Plan can be a framework that outlines future activities to develop a written DA plan.
    - FAQ-74 clarifies that operators may not have a fully developed integrity management plan by the December 17, 2004 deadline. Operators are expected to have a framework which explains how they will develop and implement the processes that will comprise their Integrity Management Plan.
  - If an operator has no plans to use DA as an integrity assessment method, then a DA Plan is not required. The remainder of Protocol D.06 through Protocol D.10 can be skipped. The operator should be reminded that such a plan must be developed prior to performing integrity assessments using DA in the future.
- The DG-ICDA is only applicable for dry gas systems that have infrequent upsets which can result in electrolytes entering the system. Inspectors should verify that the operator considered special or historical conditions that could cause internal corrosion in locations that would not be predicted by the DG-ICDA model.
  - Past history of transporting wet gas - FAQ-126 clarifies that operators cannot use the DG ICDA process on pipelines that once contained wet gas. Per both the code and the proposed NACE ICDA standard, the potential locations of corrosion can not be determined by the model in wet gas systems.
  - Past periodic hydrostatic pressure testing that could leave water in low points
  - Past indications of widespread internal corrosion
  - Corrosion damage on the top of the pipe

    - Coupons indicating active corrosion
    - Routine pigging which could have moved liquids in the pipeline to areas not predicted by the model
    - Use of cleaning pigs that also can move liquids and solids to areas not predicted by the model
    - Areas that contain solids or sludge
- Dry gas means the gas is above its dew point and without condensed liquids. In the U.S., dry gas (or "tariff gas") is typically specified as containing < 7 lb. of moisture per million cubic feet.
- The operator should use qualified individuals to make key decisions during the DG-ICDA process. [See ASME B31.8S-2004, Section 12.2(b)(4)]
- The lack of records to indicate the presence of electrolytes is not, in and of itself, sufficient justification to conclude that DG-ICDA is an appropriate assessment method. Operators must base such conclusions on a review of bona fide, accurate records of past operating conditions.
    - FAQ-105 addresses the situation of an operator not having records that show water or electrolyte contamination is not sufficient to prove that they are not threat. Both current and historical data proving no moisture or electrolyte are needed.

D.06.b. Verify that the operator's plan contains provisions for carrying out ICDA 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. [§192.927(c)(5)(iii)]

D.06.b. Supplemental Guidance:

- The operator needs show that they are assessing the entire pipeline in the DG-ICDA procedure. This is required because the 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.
- FAQ-107 clarifies that operators need to evaluate the entire segment, not just the covered segment to assess if water or electrolytes are present. These contaminants may have entered the pipeline downstream of the covered segment and migrated to it.

D.06.c. Verify that the operator implements the ICDA plan. [§192.927(c)]

D.06.c. Supplemental Guidance:

- Where operators use DA as the integrity method, they need to implement the entire ICDA process for covered segments that internal corrosion is a threat.
- The absence of data does not rule out internal corrosion as a threat.
    - FAQ-105 states that not having records that show water or electrolyte contamination is not sufficient to prove that they are not a threat. Both current and historical data proving no moisture or electrolyte are needed.
- Operators should be questioned on how they have determined that the covered segment is suitable for assessment using DG ICDA. If a pipeline was in operation in the early 1950's or earlier, there is a very good chance that it was exposed to wet gas at one time. There should be sufficient documentation to prove that the pipeline only carried dry gas.

D.07 Dry Gas ICDA Pre-Assessment, Region Identification and Use of Model

For dry gas systems, verify that the operator gathers, integrates and analyzes data and information to accomplish pre-assessment objectives and identify ICDA Regions. [§192.927(c)(1), §192.927(c)(2), ASME B31.8S-2004, Section 6.4.2, ASME B31.8S-2004, Appendix A2 and ASME B31.8S-2004, Appendix B2]

D.07 *Supplemental Guidance:*

- Internal corrosion is most likely to occur at locations where an electrolyte, typically water, first accumulates. Predicting the locations where this occurs requires knowledge of both the physical layout of the pipeline and several operating parameters. Since one of the locations that the electrolyte may accumulate is caused by laminar flow of a multiphase film, entry and exit points on the pipeline are critical.
- Refer to the following FAQs:
    - FAQ-105 addresses the situation of an operator not having records that show water or electrolyte contamination is not sufficient to prove that they are not threat. Both current and historical data proving no moisture or electrolyte are needed.
    - FAQ-126 clarifies that operators can not use the DG ICDA process on pipelines that once contained wet gas. The potential locations of corrosion cannot be determined by the model in wet gas systems.
    - FAQ-147 addresses the situation of the operator having records indicating that there are no conditions conducive to internal corrosion; Operators need only assess their covered segments for susceptible threats. If an operator has sufficient data to determine a covered segment is not susceptible to internal corrosion, then it need not be assessed for it.
    - FAQ-193 addresses the issue that a standard had not initially been approved for ICDA. Operators must use both the rule, §192.927 and ASME B31.8S-2004 as guides for performing the ICDA process. Additionally the recently issued standard, NACE SP0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas, may also be utilized as long as the requirements in §192 and ASME B31.8S-2004 are also addressed.
    - FAQ-243 addresses PHMSA expectations for determining if ICDA is feasible.

D.07.a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., region identification, feasibility determinations) in implementing the pre-assessment stage of the ICDA process. [§192.927(c)(5)(i)]

D.07.a. Supplemental Guidance:

- The operator's plan must have sufficient detail so that the inspector can determine:
    1. Whether sufficient data are available or can be collected for some ICDA regions to support making a feasibility decision regarding using the ICDA approach;
    2. Whether the data collected supports a determination that ICDA would be applicable;
    3. The parameters for identifying ICDA regions;
    4. Criteria for selecting excavation sites and conducting detailed examinations of the pipe to determine whether metal loss from internal corrosion has occurred ;
    5. The additional information to be addressed in deciding where to dig after the model has provided key inclination angles;
    6. The criteria for determining the effectiveness of the ICDA process and for determining re-assessment intervals.
- FAQ-126 clarifies that operators cannot use the DG ICDA process on pipelines that once contained wet gas. Per both the code and the proposed NACE ICDA standard, the potential locations of corrosion can not be determined by the model in wet gas systems.

- If operators chose to use ICDA in an application that is not allowed in §192.927, then they must file a notification 180 days prior to using this technology. This is covered under the "Other Technology" section of §192.921(a)(4) and §192.949.

D.07.b. Verify that the operator collects, as a minimum, the following **data and information**:

i. All data elements listed in ASME B31.8S-2004, Appendix A2 [§192.927(c)(1)(i)]
ii. Information needed to support use of a model to identify areas where internal corrosion is most likely, including locations of all 1) gas input and withdrawal points, 2) low points such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, 3) elevation profile in sufficient detail for angles of inclination to be calculated, and 4) the range of expected gas velocities within the pipeline; [§192.927(c)(1)(ii)]
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 [§192.927(c)(1)(iii)]
iv. Information where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes. [§192.927(c)(1)(iv)]

D.07.b. Supplemental Guidance:

i. In the ICDA pre-assessment step the operator must collect significant amounts of data to determine if doing an ICDA is feasible.
    - The minimum data sets needed are in ASME B31.8S-2004, Appendix A2 (see Supplemental Guidance Appendix D.03, Minimum Data Elements for Dry Gas Internal Corrosion Direct Assessment).
        - FAQ-155 clarifies operators must follow the requirements in the Appendices of ASME B31.8S-2004 when those Appendices, or sections thereof, are referenced in the rule, even though the standard indicates that the appendices are non-mandatory.
    - The operator should have knowledge of any past upsets and where they occurred.
    - Where information is not available, the operator shall make conservative assumptions.
ii. The operator must have a good physical layout of the pipeline segment (which includes both covered and non covered segments).
    - Pressure, temperature, entry points, withdrawal points must be known.
    - Angles of inclination over the entire pipeline need to be calculated and available.
    - Special features that could trap electrolytes must also be known and located. These could include but are not limited to, traps, valves, drips, dead legs and other appurtenances.
    - Typical, maximum and minimum flow rates need to be obtained. This data can then be used to determine the most likely areas that the multiphase film will accumulate and cause potential internal corrosion problems.
iii. The operator needs to have an operating history that targets when and where upsets of electrolytes have occurred.
    - History of any internal corrosion also needs to be documented.
    - Where an operator has no data on past upsets, then the operator must assume they did occur at all entry points into the pipeline.
iv. The use of cleaning pigs after the initial inauguration of the pipeline can negate the use of ICDA as an integrity method.
    - Cleaning pigs can leave residual sludge and contamination at locations not determined by the critical angle of inclination and thus makes the model ineffective. This residual sludge can contain electrolytes that will start the internal corrosion process. The residual sludge can also contain bacteria that can lead to MIC attack of the pipeline.

Refer to the following FAQs:

- FAQ-105 addresses the situation of an operator not having records that show water or electrolyte contamination is not sufficient to prove that they are not threat. Both current and historical data proving no moisture or electrolyte are needed.
- FAQ-126 clarifies that operators can not use the DG ICDA process on pipelines that once contained wet gas. The potential locations of corrosion can not be determined by the model in wet gas systems.
- FAQ-127 addresses that if operators chose to use ICDA in an application that is not allowed in §192.927, then they must file a notification 180 days prior to using this technology. This is covered under the "Other Technology" section of §192.921(a)(4) and §192.949
- FAQ-158 addresses historical operating conditions. Current conditions may not show where all possible areas of internal corrosion could exist. Latent internal corrosion could be a threat to the covered segment.

D.07.c. Verify that the operator integrates the data collected and uses the integrated data analysis to evaluate and document the following:

i. Feasibility of performing ICDA on its pipe segments [§192.927(c)(1)]
ii. Identification of all ICDA Regions and the location of each region. [§192.927(c)(1) & (2)]
iii. Support use of a model to identify the locations along the pipe segment where electrolyte may accumulate [§192.927(c)(1)]
iv. Identify areas within the covered segment where liquids may be potentially entrained. [§192.927(c)(1)]

D.07.c. Supplemental Guidance:

i. The operator needs to collect sufficient data to determine if the ICDA process is feasible for use on the covered segment. Supplemental Guidance Appendix D.03, Minimum Data Elements for Dry Gas Internal Corrosion Direct Assessment, gives the required data. In Supplemental Guidance Appendix D.04, Data Elements that Preclude the Use of Dry Gas Internal Corrosion Direct Assessment, data is shown than will immediately negate the use of ICDA in the covered segment. This data will mandate that alternative assessment methods must be used. Some data sets that do not allow the use of DG ICDA are:
    - Routine and periodic hydro-testing of the segment
    - Routine and periodic use of both cleaning and measurement pigs
    - Insufficient data
    - Flow rates, temperature and pressures outside of the model's requirement
    - Corrosion on the top of the pipe
    - Conversion of the pipeline from a service that DG ICDA is not applicable
ii. The operator must have a procedure for using the data obtained on the covered and non covered segments to select reasonable and workable ICDA regions.
    - These regions can include areas that are not covered under the regulations for remediation, but must be considered for determination of the internal corrosion threat.
    - Changes in flow rates, gas pressure, temperature or composition require a change in ICDA regions. (See Supplemental Guidance Appendix D.05, Internal Corrosion Direct Assessment – Region Definition, for an example)
iii. The operator must use the data collected in the pre-assessment step to populate the GRI model
    - Uses data sets to determine the critical angle of inclination
        - Under §192.927, ICDA regions are bounded by the entry point of the electrolyte and the furthest location downstream that could be affected by internal corrosion. The furthest location down stream would be the greatest critical angle. This angle can be calculated by using the conditions that would cause the

greatest flow, i.e. gas velocity, temperature or pressure in any combination. See the additional guidance provided below for guidance on flow rates.

    - In the case where a pipeline has had no flow (shut down) for an extended length of time, several issues become important. In the no flow state, there can not be any introduction of electrolytes and thus no new areas of internal corrosion. Prior to the cessation of flow, electrolytes may have been present and flow rates and conditions at that time need to be used to determine the location of ICDA regions and the most likely locations of internal corrosion based on the flow model. Another issue is if the line was dehydrated for long term preservation or flow was just cut off. If the line was just shut down and pockets of electrolyte remained, these pockets could have evaporated and cooling of the surrounding soil could have caused condensation. If this did occur, the use of ICDA is precluded. If the line was dry, then only past internal corrosion is an issue and that can be determined based on historic flow rates and conditions
  - Uses conservative assumptions where data is not available or,
    - Where operators do not have good flow rate data, they may make conservative assumptions on what the maximum flow rate would have been based on historic records. These assumptions must be documented and a technical justification needs to be provided. Operators can use a range of flow rates and select ICDA excavation sites based on them. See the additional guidance provided below for guidance on flow rates. If they can not make these conservative assumptions, then ICDA may not be feasible
  - Determines that DG ICDA is not feasible
    - Lack of the required data elements, such as the historic flow rates, the location of current and past entry points where electrolytes could have entered the segment, a precise and accurate inclination profile may preclude the use of ICDA as an assessment method.
    - In a no flow condition where a line was idled and electrolyte was present and could have evaporated and then condensed over time, the use of ICDA is precluded.

iv. See Protocol D.08.a.

Refer to the following FAQs:

- FAQ-81 addresses the need to consider several types of information during an ICDA. This data consists of threat analyses, previous assessments, corrosion history, operating history, failure consequences and leak and incident history.
- FAQ-105 addresses an operator not having records that show water or electrolyte contamination is not sufficient to prove that they are not threat. Both current and historical data proving no moisture or electrolyte are needed.
- FAQ-126 clarifies that operators can not use the DG ICDA process on pipelines that once contained wet gas. The potential locations of corrosion can not be determined by the model in wet gas systems.
- FAQ-127 addresses notifications when using on pipe with wet gas. If operators chose to use ICDA in an application that is not allowed in §192.927, then they must file for a waver 180 days prior to using this technology. This is covered under the "Other Technology" section of §192.921(a)(4) and §192.949.
- FAQ-158 addresses historical operating conditions. Current conditions may not show where all possible areas of internal corrosion could exist. Latent internal corrosion could be a threat to the covered segment.
- FAQ-235 notes that if guided wave technology is being used as a tool to examine the predicted locations to determine if corrosion exists, then it is being used in a manner consistent with the ICDA process and would not be considered "other technology". If, on the other hand, the intent is to use guided wave technology in some other manner to assess internal corrosion (e.g., not first

analyzing the pipeline to determine likely locations for internal corrosion), then its use would be different from the normal ICDA process and it would be considered "other technology".

Flow Rate Reasoning from GRI 02-0057

Most pipelines have experienced a range of gas velocity from zero to a maximum, which complicates the procedure for determining the critical angle of inclination. Critically large inclinations will trap water at any velocity up to a maximum, but upstream locations with lower angles of inclination may trap water at velocities less than the maximum. Because of this, examination of inclinations above the critical angle can be used to assess the integrity of downstream pipe, but the integrity of upstream pipe remains unknown. If information exists about the period of time a pipeline has experienced velocity ranges, engineering judgment can be used to determine if short velocity changes are significant. The procedure for the ICDA approach (considering a range of gas velocities) is:

- Find the first pipe inclination greater than the largest critical angle determined by the range of operating conditions and the flow modeling results. If all inclinations have angle larger than critical, choose the angle of greatest inclination along the pipeline length.
- Perform detailed examination/inspection of the target location(s). If no corrosion is found, it is concluded that downstream corrosion is unlikely. However, if a range of velocity (or other relevant parameter) exists so the critical angle for accumulation may be smaller at certain times, upstream integrity cannot be determined by examination of a downstream inclination.
- Perform detailed examination/inspection on the location(s) with highest inclination upstream of the initial location(s). This will provide integrity information on the pipe downstream of the intermediate inclination point(s) and the first inclination with angle higher than the maximum critical angle.
- Along with choosing locations having inclinations above critical angle, any fixture that can trap water (e.g., drip, valve, stub-end) serves as an examination point. Upstream water traps can accumulate water (or other electrolyte) before it reaches an inclination greater than critical angle; these fixtures should therefore be examined, but they do not replace examination of the pipe because the rate of accumulation depends on the geometry of the fixture. Ideally, water that accumulates at a location with inclination greater than critical angle will evaporate before filling and carrying over to the next location. However, a scenario can be envisioned where a short upset with large liquid volume fills an accumulation point and carries over to a fixture that traps the water. This condition is acceptable if the water evaporation rate is similar because the upstream accumulation point will be exposed to the water for a longer period of time (and therefore suffers more corrosion). However, if the trap geometry restricts evaporation, it is possible for corrosion to be more severe inside of the downstream trap. Therefore, traps of similar design directly downstream of a pipe inclination with angle greater than critical should be examined.

D.07.d. Verify the operator's plan uses the model in GRI 02-0057 ICDA of Gas Transmission Pipelines-Methodology (or equivalent acceptable model) to define critical pipe angle of inclination above which water film cannot be transported by the gas, and that the model considers, as a minimum: [§192.927(c)(2)]

i. Changes in pipe diameter, [§192.927(c)(2)]
ii. Locations where gas enters a line, [§192.927(c)(2)]
iii. Locations down stream of gas draw-offs. [§192.927(c)(2)]
iv. Other conditions that may result in changes in gas velocity. [§192.927(c)(2) and GRI 02-0057]

D.07.d. Supplemental Guidance:

- The operator must use either the GRI model (see GRI Report 02-0057, Reference: GRI-020057) or a validated equal.
    - The GRI and validated NACE models are discussed in Supplemental Guidance Appendix D.06, Flow Modeling & Inclination Profile.

- The operator also must use the physical data obtained in the pre-assessment step to calculate the inclination angles along the entire covered segment within each ICDA region. (See Supplemental Guidance Appendix D.06, Flow Modeling and Inclination Profile, for the inclination angle formula)
- Where there are inclination angles and other features that could hold up the multiphase film of liquids outside of the covered segment but still within the same ICDA region, they also must be evaluated.
- In the case where flow within a segment can be bi-directional, then separate ICDA regions must be set up for flow in each direction

D.07.e. Verify that the operator's plan contains provisions for applying more restrictive criteria for pre-assessment and region identification when conducting ICDA for the first time on a covered segment. [§192.927(c)(5)(ii)]

D.07.e. Supplemental Guidance:

- The operator needs to specify what additional criteria or more restrictive interpretation of the existing criteria will be used for the initial ICDA on a covered segment. These can be but are not limited to:
  - running the flow model at a range of flow rates to determine the sensitivity of the critical angle to various flow conditions experienced over time
  - reducing the size of the ICDA region
  - additional data requirements
  - taking additional data to better define the inclination profile of a pipeline, such as depth of cover readings every 5' and using a land surveyor for determining the exact inclination profile every 25'
  - obtaining upset information from both suppliers and other operators with the same supplier but upstream of entry points
- Operators must document these more restrictive criteria. This documentation may consist of:
  - operators can use two sets of requirements, one for the initial ICDA on a region or segment and the other for subsequent ICDA assessments on those regions or segments
  - operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ICDA on a region or segment
  - operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it

D.08 Dry Gas ICDA Direct Examination

For dry gas systems, verify that the operator (1) identifies locations where internal corrosion is most likely in each ICDA region and (2) performs direct examinations of those locations. [§192.927(b), 192.927(c)(3), ASME B31.8S-2004, Section 6.4 and ASME B31.8S-2004, Appendix B2]

***D.08** Supplemental Guidance:*

- An operator must identify those locations where internal corrosion would be the most likely to occur. In all cases, at least two locations in each ICDA region and within the covered segments in those regions must be identified.

D.08.a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., identifying locations most likely to have internal corrosion, selection of examination tools) in implementing the direct examination stage of the ICDA process. [§192.927(c)(5)(i)]

D.08.a. Supplemental Guidance:

- The operator's plan must have sufficient detail so that the inspector can determine:
    1. Whether sufficient data are available or can be collected for some ICDA regions to support making a feasibility decision regarding using the ICDA approach;
    2. Whether the data collected supports a determination that ICDA would be applicable;
    3. The parameters for identifying ICDA regions;
    4. Criteria for selecting excavation sites and conducting detailed examinations of the pipe to determine whether metal loss from internal corrosion has occurred ;
    5. The additional information to be addressed in deciding where to dig after the model has provided key inclination angles;
    6. The criteria for determining the effectiveness of the ICDA process and for determining re-assessment intervals.
- FAQ-126 clarifies that operators cannot use the DG ICDA process on pipelines that once contained wet gas. Per both the code and the proposed NACE ICDA standard, the potential locations of corrosion can not be determined by the model in wet gas systems.
- If operators chose to use ICDA in an application that is not allowed in §192.927, then they must file a notification 180 days prior to using this technology. This is covered under the "Other Technology" section of §192.921(a)(4) and §192.949.
    - FAQ-127 states an operator must notify PHMSA (or the appropriate State) if they plan to use ICDA to assess a system transporting gas that with an electrolyte nominally present in the gas stream.
- FAQ-158 requires the consideration of historical information. Current conditions may not show where all possible areas of internal corrosion could exist. Latent internal corrosion could be a threat to the covered segment.

D.08.b. Verify the operator has identified locations where internal corrosion is most likely to exist in each ICDA region and where electrolyte accumulation is predicted. [§192.927(c)(3), ASME B31.8S-2004, Section 6.4.2 and ASME B31.8S-2004, Appendix B2.3]

D.08.b. Supplemental Guidance:

- An operator must identify all those locations that meet the both the critical angle of inclination and the locations that may trap liquids through their design.
    - For each ICDA region, at least two locations must be identified and examined (in the covered segment).
    - In the case where flow within a segment can be bi-directional, then separate ICDA regions must be set up for flow in each direction and thus at least 4 excavations must be performed.
    - For critical angles that are part of a short and sharp rise, the most likely location for electrolyte hold up is along the short up hill section.
    - For more gradual and longer inclines over mountains and hills, the hold up point can be more widespread and longer. Excavations need to take this into account.

D.08.c. Verify the operator requires a direct examination for internal corrosion using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique of those covered segment locations where internal corrosion is most likely to exist, and includes as a minimum, the following: [§192.927(c)(3), ASME B31.8S-2004, Section 6.4.2, ASME B31.8S-2004, Appendix B2.3 and ASME B31.8S-2004, Appendix B2.4]

i. A minimum of two (2) locations within each ICDA region within a covered segment,
ii. At least one location must be the low point (e.g., sags, drips, valves, manifolds, deadlegs, traps) nearest the beginning of the ICDA region and
iii. The second location must be further downstream within a covered segment near the end of the ICDA Region (The end of the ICDA region is the farthest downstream location where the ICDA model predicts electrolytes could accumulate based on the critical angle of inclination above

which water film cannot be transported by the gas). [§192.927(c)(2) and ASME B31.8S-2004, Appendix B2.3]

D.08.c. Supplemental Guidance:

- Each of the locations that have been identified as potential hold up points needs to be examined. The purpose of the examination is to determine if there has been any internal corrosion on that particular pipe section.
    - Use of ultrasonic testing equipment, x-ray equipment or other accepted methods by qualified individuals to determine internal wall loss needs to be undertaken.
    - Documentation of all of the findings must be available for inspection. If there is wall loss due to internal corrosion, calculations on remaining pipe strength must be performed and the results compared to the MAOP times a safety factor.
        - FAQ-229 addresses the use of safety factors in calculating the reduced operating pressure if the blanket 20% reduction is not used.
    - If defects other than internal corrosion are found, appropriate alternative assessment methods must be performed to determine the integrity of the covered segment. See Supplemental Guidance Appendix D.07, Direct Examination of a Dry Gas Internal Corrosion Direct Assessment Location, for other activities associated with the Direct Examination of an ICDA location.

D.08.d. If internal corrosion exists at any location directly examined, verify that the operator: [192.927(c)(3)]

i. Evaluates the severity of the defect and remediates the defect per §192.933 (see Protocol E) [§192.927(c)(3)(i)], and
ii. Either performs additional excavations or performs additional assessment using an allowed alternative assessment method [§192.927(c)(3)(ii)], and
iii. Evaluates 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 remediates the conditions per §192.933. [§192.927(c)(3)(iii)]

D.08.d. Supplemental Guidance:

- When the operator discovers internal corrosion at a site determined by the model,
    - A full evaluation of the site is required and the remaining wall strength must be calculated.
    - If necessary, remediation actions also must also be completed.
    - Additional potential liquid sites need to be examined or alternative methods of determining the integrity of the covered segment must be used.
    - Lastly, the knowledge gained from this ICDA must be used on similar segments, both covered and non-covered to prevent further occurrences. Remediation of the covered segment is required.
- FAQ-132 addresses the determination of a new reassessment schedule for defects requiring remediation. Re-assessment under the CDA process uses the remaining life calculation and half life calculations in NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3. These calculations give operators the allowable re-assessment interval of internal corrosion defects providing they are less than the maximum in ASME B31.8S-2004, Table 3 or §192.939.

D.08.e. Verify that the operator's plan contains provisions for applying more restrictive criteria for the direct examination when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

D.08.e. Supplemental Guidance:

- The operator needs to specify what additional criteria or more restrictive interpretation of the existing criteria will be used for the initial ICDA on a covered segment. These can be but are not limited to:
    - additional excavations
    - using additional tools to verify the location and depth of any internal corrosion, such as both UT and X-ray or guided wave UT at all locations in addition to local UT or X-ray
    - making larger excavations to ensure that all internal corrosion was discovered
- Operators must document these more restrictive criteria. This documentation may consist of:
    - operators can use two sets of requirements, one for the initial ICDA on a region or segment and the other for subsequent ICDA assessments on those regions or segments
    - operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ICDA on a region or segment
    - operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it

D.09 Dry Gas ICDA Post-Assessment

For dry gas systems, verify that the operator performs post-assessment evaluation of ICDA effectiveness and continued monitoring of covered segments where internal corrosion has been identified. [§192.927(c)(4)]

D.09 *Supplemental Guidance:*

- An operator must determine if the ICDA process was effective in locating areas of internal corrosion on covered segments. Continued monitoring for internal corrosion of those segments is also required.

D.09.a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., reassessment interval determination, techniques for monitoring internal corrosion) in implementing the post-assessment evaluation stage of the ICDA process. [§192.927(c)(5)(i)]

D.09.a. Supplemental Guidance:

- The operator's plan must have sufficient detail so that the inspector can determine:
    1. Whether sufficient data are available or can be collected for some ICDA regions to support making a feasibility decision regarding using the ICDA approach;
    2. Whether the data collected supports a determination that ICDA would be applicable;
    3. The parameters for identifying ICDA regions;
    4. Criteria for selecting excavation sites and conducting detailed examinations of the pipe to determine whether metal loss from internal corrosion has occurred ;
    5. The additional information to be addressed in deciding where to dig after the model has provided key inclination angles;
    6. The criteria for determining the effectiveness of the ICDA process and for determining re-assessment intervals.
- FAQ-126 clarifies that operators cannot use the DG ICDA process on pipelines that once contained wet gas. Per both the code and the proposed NACE ICDA standard, the potential locations of corrosion can not be determined by the model in wet gas systems.
- If operators chose to use ICDA in an application that is not allowed in §192.927, then they must file a notification 180 days prior to using this technology. This is covered under the "Other Technology" section of §192.921(a)(4) and §192.949.
    - FAQ-127 states an operator must notify PHMSA (or the appropriate State) if they plan to use ICDA to assess a system transporting gas that with an electrolyte nominally present in the gas stream.

- FAQ-158 requires the consideration of historical information. Current conditions may not show where all possible areas of internal corrosion could exist. Latent internal corrosion could be a threat to the covered segment.

D.09.b. Verify the operator has a process for **evaluating the effectiveness** of ICDA as an assessment method and **determining reassessment intervals**. [§192.927(c)(4)(i) and ASME B31.8S-2004, Appendix B2.4]

i. Verify that if corrosion is found in areas where the pipeline inclination is greater than the estimated critical inclination, that the operator re-evaluates the critical inclination angle and additional new areas are selected for direct examination. [ASME B31.8S-2004, Appendix B2.4]
ii. Verify the operator's process determines whether a segment must be reassessed at intervals more frequently than those specified in §192.939 using the largest defect most likely to remain in the covered segment as the largest defect discovered in the ICDA segment and estimating the reassessment interval as half the time required for the largest defect to grow to critical size. Verify that this evaluation is to be carried out within one year of completion of the assessment. [§192.927(c)(4)(i) and §192.939(a)(3)]
iii. Verify the operator's reassessment intervals comply with the following maximum allowed intervals in accordance with 192.939 (see Protocol F). [§192.939(b)]
    1. 10 years for segments operating at SMYS levels greater than 50%
    2. 15 years for segments operating between 30 and 50% SMYS
    3. 20 years for segments operating below 30% SMYS

D.09.b. Supplemental Guidance:

- An operator is required to determine the effectiveness of the entire ICDA process. Some areas that must be evaluated are the level 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.
    - If corrosion is found at locations where the critical angle of inclination was exceeded in the covered segment, the operator must rerun the model and check additional areas for internal corrosion.
    - If this is not feasible, then alternative methods of assessing the integrity of the covered segment must be used.
    - If corrosion was found to be widespread or on top of the pipe, then the assumptions of infrequent upsets may be in error and alternative methods of assessing the integrity of the covered segment must be used.
- 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. If an operator has data showing that a shorter reassessment period is appropriate, then this should be used.
- In no case may the reassessment interval exceed the maximum that is provided in §192.939(b). Additional knowledge of the covered segments and testing may yield a shorter reassessment period.
- FAQ-132 addresses the determination of a new reassessment schedule for defects requiring remediation. Re-assessment under the CDA process uses the remaining life calculation and half life calculations in NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3. These calculations give operators the allowable re-assessment interval of internal corrosion defects providing they are less than the maximum in ASME B31.8S-2004, Table 3 or §192.939.

D.09.c. Verify the operator continually monitors 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 them for corrosion products. [§192.927(c)(4)(ii)]

i. Verify the operator has a process to determine the frequency for monitoring and liquid analysis based on all integrity assessments results conducted in accordance with 192 Subpart O and risk factors specific to the covered segment. [§192.927(c)(4)(ii) and ASME B31.8S-2004, Appendix A2.2]

ii. Verify the operator's process requires that if any evidence of corrosion products is found in the covered segment, prompt action must be taken including, as a minimum: [§192.927(c)(4)(ii)]
   1. Remediate the conditions the operator finds in accordance with §192.933, and
   2. Implement one of the two following required actions: (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.

D.09.c. Supplemental Guidance:

i. Where an operator uses one or more of the approved monitoring techniques, they must have a program to check on the results at a fixed interval.
   - This interval needs to be sufficiently short enough to detect and correct any threats to the integrity of the covered segment.
   - The actions can include, but are not limited to, drawing off fluids from low points or collection areas, measuring coupons, checking electronic probes, etc.

ii. When an operator finds evidence of either internal corrosion or corrosion products in the covered segment, they must take prompt action to remediate the condition and conduct excavations downstream of the entry point of electrolyte or perform a reassessment of the entire covered segment using alternative assessment methods.

D.09.d. Verify that the operator's plan contains provisions for applying more restrictive criteria for the post-assessment when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

D.09.d. Supplemental Guidance:

- The operator needs to specify what additional criteria or more restrictive interpretation of the existing criteria will be used for the initial ICDA on a covered segment. These can be but are not limited to:
  - additional validation procedures,
  - use of two or more monitoring techniques
  - reducing the interval for re-assessment to that below the half life
- Operators must document these more restrictive criteria. This documentation may consist of:
  - Operators can use two sets of requirements, one for the initial ICDA on a region or segment and the other for subsequent ICDA assessments on those regions or segments
  - Operators can use one set of requirements but they need to highlight the "more restrictive criteria" required on the initial ICDA on a region or segment
  - Operators can provide inspectors with a listing of the more restrictive criteria and where it was used and what was the outcome of using it

D.10 Wet Gas ICDA Programmatic Requirements

If the operator elects to use ICDA to assess a covered segment operating with electrolyte present in the gas stream (wet gas), verify that the operator develops and implements an ICDA plan in accordance with §192.927 which addresses the following. [§192.927(b)]

D.10 *Supplemental Guidance:*

- If an operator will be using ICDA on a pipeline that either carries or at one time carried wet gas, then the operator must develop a plan to use the modified ICDA process.

- Dry gas means the gas is above its dew point and without condensed liquids. In the U.S., dry gas (or "tariff gas") is typically specified as containing < 7 lb. of moisture per million cubic feet. Therefore, if a gas has greater than or equal to 7 lb. of moisture per million cubic feet, it would be classified as wet gas.

D.10.a. Verify that the operator developed a documented ICDA plan which demonstrates how the operator will conduct ICDA on the entire pipeline in which covered segments are present to effectively address internal corrosion. [§192.927(c)]

D.10.a. Supplemental Guidance:

- Where an operator plans on using ICDA on a covered segment, they must develop a plan specific to that entire pipeline, not just the covered segment

D.10.b. Verify the operator has provided notification to PHMSA, and applicable state or local safety authorities, of an ICDA wet gas "other technology" application in accordance with §192.921 (a) (4) or §192.937 (c) (4). [§192.927(b)]

D.10.b. Supplemental Guidance:

- The plan developed by the operator for performing ICDA on a wet gas pipeline is considered "other technology" and PHMSA and the applicable state or local safety authorities must be notified of this application of technology (covered under Sections 192.921, 192.937 and in accordance with 192.949).
- FAQ-127 clarifies that the ICDA process described in NACE RP0502-2002 is for dry-gas systems. The rule requires that operators who plan to use ICDA for systems transporting gas containing an electrolyte develop a plan (192.927(b)). Such use of ICDA is considered "other technology". Operators must submit notification of their planned use of this technology at least 180 days before the assessment is scheduled as required by §192.921(a)(4) and §192.949. Operators should be encouraged to submit notifications as early as they can.

D.11 SCCDA Data Gathering and Evaluation

If the operator elects to use SCCDA, verify that the operator's SCCDA evaluation process complies with ASME B31.8S-2004, Appendix A3 in order to identify whether conditions for SCC of gas line pipe are present and to prioritize the covered segments for assessment. [§192.929(b)(1)]

D.11 *Supplemental Guidance:*

- Operators must screen their pipelines to determine whether the risk of SCC may be present. If SCC may be present the operator must implement an SCC Plan. The initial screening of pipeline segment data consists of identifying locations where **5 criteria** for risk of **high pH SCC** on gas pipelines are present. ASME B31.8S-2004, Appendix A3 screens for the following 5 factors:
    1. Operating stress (MAOP) greater than 60% SMYS,
    2. Operating temperature greater than 100 degrees F,
    3. Distance downstream from compressor station less than or equal to 20 miles,
    4. Age of pipeline greater than or equal to 10 years , and
    5. Coating type other than fusion bond epoxy (FBE).
- 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.

- Operators may use the following **4 criteria** to screen for risk of **near-neutral pH SCC** per NACE RP0204-2004, Section 1.2.2:
    1. Operating stress (MAOP) greater than 60% SMYS,
    2. Distance downstream from compressor station less than or equal to 20 miles,
    3. Age of pipeline greater than or equal to 10 years , and
    4. Coating type other than fusion bond epoxy (FBE).
- Refer to the following FAQs which provide information regarding alternative plans and associated notifications to PHMSA:
    - FAQ-97 addresses what types of notifications are required by the rule.
    - FAQ-98 addresses when notifications must be submitted.
    - FAQ-99 addresses what information must be in a notification.
- FAQ-128 clarifies that the rule requires that operators using SCCDA systematically gather and analyze excavation data for pipe at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME B31.8S-2004, Appendix A3.3 indicate the potential for SCC (192.929(b)(1)). Relevant data from pipe not in covered segments must be considered in this process.
    - Additional discussion of this requirement is provided in Supplemental Guidance Appendix C.03, White Paper, "Look Beyond" Provisions and in NACE RP0204-2004, Table 2, Data Collected at an Excavation Site in an SCCDA Program and Relative Importance.
- Some practical applications of how SCC data obtained from non-covered segments could impact how an operator manages pipeline integrity on covered segments are shown below. The following listing contains examples, and is not an exhaustive list. Operators should appropriately respond to SCC found in non-covered segments based on the specifics of each circumstance.
    - Use fracture mechanics analysis (including cyclic loading) and the worst as-found crack size to predict remaining life
    - Since there would be no difference between the HCA segment and the non-HCA segment in terms of the SCC susceptibility criteria, it would be prudent to assume that similar defects could exist in the covered segments
    - Based on the remaining life prediction of the known defect in the pipeline, operators should re-evaluate the assessment schedule to see if it needs to be accelerated
    - Known SCC defects in non-covered segments of a pipeline that contains covered segments should cause the operator to also re-evaluate the selection of assessment methods, and possibly change to hydrostatic pressure testing or ILI
    - If the operator continues to use SCCDA, they should carefully analyze the non-HCA segment to determine the conditions that accompanied the SCC. For example, if coating was disbonded at the SCC location, a coating survey should be performed and areas of poor or disbonded coating (discovered or suspected) should influence selection of (and number of) SCCDA dig locations in the HCA. The same could be said of soil conditions, areas of general corrosion, or other conditions that coincided with the SCC.
    - If they found near-neutral SCC, they would need to re-evaluate the lines considered to be susceptible by excluding the temperature criterion (and possibly the 20-mile criterion), to expand the area considered to be susceptible. (For example, suppose only the first 10 miles downstream from the compressor station was initially considered susceptible because of the temperature criteria. If near-neutral pH SCC is found, the area of susceptibility would need to be expanded to cover 20 miles downstream of the compressor station.)
- Additional guidance concerning stress corrosion cracking can be found in Supplemental Guidance Appendix D.08, Stress Corrosion Cracking, and Advisory Bulletin ADB-03-05, Stress Corrosion Cracking Threat to Gas and Hazardous Liquid Pipelines, October 8, 2003 (Reference: ADB-0305).

D.11.a. Verify that the operator has a process to **gather, integrate, and evaluate data** for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. [§192.929(b)(1)]

i. Verify that the operator's process gathers and evaluates data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC. [§192.929(b)(1) and ASME B31.8S-2004, Appendix A3.3]
ii. Verify that the data includes, as a minimum, the data specified in ASME B31.8S-2004, Appendix A3.
iii. Verify that the operator addresses missing data by either using conservative assumptions or assigning a higher priority to the segments affected by the missing data, as required by ASME B31.8S-2004, Appendix A3.2.

D.11.a. Supplemental Guidance:

- FAQ-223 addresses the kind of information that must be collected to use stress corrosion cracking direct assessment process.
- FAQ-243 addresses PHMSA expectations for determining if SCCDA is feasible.
- Factors to consider in establishing pipeline segment priorities and excavation sites include areas susceptible or experiencing disbonded coating or coating degradation, previous history of SCC, periods of lost or low cathodic protection, ground movement areas affecting coating condition, poor backfill conditions or other undesirable construction practices, residual stresses such as at bends or dents, moisture drainage, topography and land use, and consequences to the public.
    - For additional background on prioritization and site selection, refer to:
        - NACE RP0204-2004, Table 1, Prioritization of Susceptible Segments and in Site Selection for SCCDA
        - NACE RP0204-2004, Table A1, Description of "Stress Corrosion Cracking Susceptible" Terrain Conditions for Polyethylene Tape-Coated Pipelines
        - NACE RP0204-2004, Table A2, Description of "Stress Corrosion Cracking Susceptible" Terrain Conditions for Some Asphalt/Coal Tar Enamel Coated Pipelines
    - NACE RP0204-2004 provides additional discussion on the selection of dig sites. The standard indicates that industry experience provides the following guidance for selection of more probable sites:
        - Locations where there is a history of SCC.
        - If previous SCC locations have been associated with unique characteristics of the pipe, digging should take place in other areas with those same characteristics.
        - If there is no history of SCC in the area of interest, locations with coating anomalies should be considered.
        - If ILI tools have been run in pipe, locations of dents or general corrosion should be considered.
        - Locations where the stresses, pressure fluctuations, and temperatures were highest or where there has been a history of coating deterioration should be selected.
        - For subsequent digs in the same area, sites should be selected that have the same unique features that were revealed in earlier digs.
- A pipeline segment is susceptible to high-pH SCC if all of the following 5 factors are met:
    1. Operating stress (MAOP) greater than 60% SMYS,
    2. Operating temperature greater than 100 degrees F,
    3. Distance downstream from compressor station less than or equal to 20 miles,
    4. Age of pipeline greater than or equal to 10 years , and
    5. Coating type other than fusion bond epoxy (FBE).
- The same factors and criteria can be used for the selection of segments of a pipeline that are potentially susceptible to near neutral pH SCC, with the exclusion of the temperature criterion (Re: NACE RP0204-2004, Section 1.2.2).
- If a pipeline segment has experienced an SCC incident or hydro test leak or rupture the pipeline segment is also at risk unless the root cause(s)of the SCC have been corrected.

- Operators must document the sites taken to determine the full extent and locations of other areas of suspected SCC, including locations on non-covered pipelines as per §192.917(e)(5).

D.12 SCCDA Assessment, Examination and Threat Remediation

Verify that covered segments (for which conditions for SCC are identified) are assessed, examined, and the threat remediated. [§192.929(b)(2)]

D.12 *Supplemental Guidance:*

- Each operator's SCCDA plan must provide that if the 5 conditions for high pH SCC are identified, the operator must assess the covered segment using:
    - The bell hole examination and evaluation method, or
    - The hydrostatic testing method.
- Each segment meeting the 5 at risk criteria for SCC must have a written inspection, examination, and evaluation plan prepared as specified in ASME B31.8S-2004, Appendix A3.
- Any significant SCC discovered must be remediated by replacement, reinforcement, hydrostatic test, Engineering Assessment, and placed under a hydrostatic retest program. Refer to the requirements of ASME B31.8S-2004, Appendix A3.4.

D.12.a. Verify, if conditions for SCC are present, that the operator **conducts an assessment** using one of the methods specified in ASME B31.8S-2004, Appendix A3.

D.12.a. Supplemental Guidance:

- The operator's documentation must require that each segment experiencing an SCC failure or meeting the 5 SCC screening criteria:
    - Have a written Inspection, Examination, and Evaluation Plan as required by ASME B31.8S-2004, Appendix A3.4
    - Identify an assessment method for the segment per ASME B31.8S-2004, Appendix A3.4. Methods allowed are:
        - Bell Hole Examination and Evaluation Method
        - Hydrostatic Testing Method

D.12.b. Verify that the operator's plan specifies an acceptable **inspection, examination, and evaluation plan** using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S-2004, Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of ASME B31.8S-2004, Appendix A3.4 (b)).

i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME B31.8S-2004, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME B31.8S-2004, Appendix A3.4.

D.12.b. Supplemental Guidance:

- The following is a summary of the requirements contained in ASME B31.8S-2004, Appendix A3.4:
    - If using the bell hole examination and evaluation method, the operator's documentation must verify that:
        - Safety precautions have been identified and employed during direct examinations,

        - Identify the most likely dig sites for SCC (refer to NACE RP0204-2004, Table 2, Data Collected at an Excavation Site in an SCCDA Program and Relative Importance, for data categories and guidance for establishing priorities for SCC susceptible segments as well as for selecting sites for excavation and examination) -- [NOTE: NACE RP0204-2004 contains detailed guidance on how to select sites for excavation and examination],
        - Procedures detail the environment and pipe examination morphology, including addressing areas of coating disbondment,
        - Pipe is inspected using magnetic particle inspection (MPI) with a documented inspection procedure.
    - If no SCC is found, a re-inspection interval for additional bell hole inspections must be identified.
    - If SCC is found, operators must document their mitigation methodology including:
        - Repair or removal methods; or
        - Hydrostatic testing of the affected valve section per ASME B31.8S-2004, Appendix A3.4; or
        - Results of any further mitigation methods identified (coating and or cathodic protection activities).
    - If using the Hydrostatic Testing method the operator's documentation must verify that:
        1. Establish a high point test pressure equivalent to minimum of 100% SMYS.
        2. Maintain the target test pressure for a minimum period of 10 minutes.
        3. Upon returning the pipeline to gas service, conduct a flame ionization survey of the pipeline segment.
        4. Address results of the testing.
    - If no leaks or ruptures due to SCC occurred, the operator shall use one of the following two options to address long term mitigation of SCC (also refer to ASME B31.8S-2004, Section 7.3.2(a)):
        - Implement a written Hydrostatic retest program with a technically justifiable interval, or
        - Perform an Engineering Critical Assessment to evaluate the risk and identify further mitigation methods.
    - If a leak or rupture due to SCC occurred, the operator shall address long term mitigation of SCC by implementing a written hydrostatic retest program for the subject valve section, with a technically justified interval (also refer to ASME B31.8S-2004, Section 7.3.2(b)).
- When performing an Engineering Critical Assessment (ECA), an ECA must evaluate the risks of SCC and provide a technically defensible plan which ensures pipeline safety. The ECA must consider the defect growth mechanisms of the SCC process.
    - For additional information, refer to TTO-08, Stress Corrosion Cracking, Appendix A, Section A.3.2, Crack Growth Models (Reference: TTO-08)
    - Also refer to Supplemental Guidance Appendix D.09, Crack Growth Mechanisms and Models.
- The operator's documentation must also verify that:
    - Each segment experiencing an SCC incident or hydrostatic test failure has a written evaluation plan, and
    - The segment has been subjected to the hydrostatic testing method for SCC within 12 months of that failure.
    - Note: hydrostatic pressure testing is required; use of other test mediums is not permitted.

D.12.c. Verify that assessment results are used to determine **reassessment intervals** in accordance with §192.939(a)(3); (see Protocol F). [§192.939(a)(3)]

D.12.c. Supplemental Guidance:

- ASME B31.8S-2004, Appendix A3.4, requires the operator to determine technically justifiable re-assessment intervals for long term mitigation of SCC.
    - Also refer to Supplemental Guidance Appendix D.09, SCC Crack Growth Mechanisms and Models.
- If no SCC leaks or ruptures occur the operator shall implement a written hydrostatic retest program or other inspection program with a technically justifiable interval.
- If a leak or rupture due to SCC occurred, the operator shall address long term mitigation of SCC by implementing a written hydrostatic retest program for the subject valve section, with a technically justified interval (also refer to ASME B31.8S-2004, Section 7.3.2(b)).
- ASME B31.8S-2004, Appendix A3.6, requires the operator to establish SCCDA Plan safety performance measures. The purpose of the measures is to determine the effectiveness of the program and to confirm the re-inspection interval.
- Operator's documentation must demonstrate performance measures have been established as follows:
    1. number of SCC in-service leaks/failures,
    2. number of SCC repair or replacements, and
    3. number of SCC hydrostatic test failures
    4. a process has been established to gather the data and monitor the program's performance

Protocol Area E. Remediation

- E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling
- E.02 Program Requirements for Identifying Anomalies
- E.03 Operator Response when Timelines for Evaluation and Remediation Cannot be Met
- E.04 Record Review for Discovery, Repair and Remediation Activities
- Table of Contents

E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling

Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity. [§192.933(a)]

***E.01** Supplemental Guidance:*

- Additional guidance on discovery can be found in Supplemental Guidance Appendix E.01, White Paper, Discovery of Condition Date.
- Inspectors should perform a comprehensive review of the operators program for performing ILI assessments. (A comprehensive review of DA assessments is covered in Protocol D.) One of the most important aspects of integrity management is discovering defects in the pipe before they grow to a critical size and fail, leak, or rupture. Operator processes for conducting ILI assessments should be investigative and have the necessary controls in place to provide reasonable assurance that all integrity threats are discovered and remediated.
- Two key aspects of discovering anomalies are:
    - **Integrated information analysis**: Information from ILI or DA assessments must be integrated with other information in order to identify defects that represent integrity threats. While most defects can be discovered from a review of assessment data alone, some defects may not be obvious from the assessment data. Integration of other data with

ILI data is a very important step for an operator to take to assure that defects are discovered.

- Examples of data with which ILI results should be integrated include:
  - Data indicative of TPD risk (foreign line crossings, one-calls, encroachments, ROW surveys, aerial surveys, construction activity on or near the ROW).
  - Surveillance, testing, and other monitoring data (previous ILI results, CIS, coating surveys such as ACVG or DCVG, coupon data, etc.)
  - Operational data (cyclic loading, etc.)
  - Maintenance, repair, as-built, and other available data (repair records, maintenance records, etc.)
- For more detailed information regarding review of ILI assessment results, see Supplemental Guidance Appendix E.02, Bookmark E04 Integrated Analysis of Assessment Results.
- For more detailed information on integrating data with ECDA results, refer to Protocol D.

- **ILI vendor contract specifications**: ILI vendors have a tremendous affect on the effectiveness and quality of ILI assessments. Operators should have formal, contractual controls in place to properly manage ILI assessments and assure that integrity threats are discovered in a timely manner. See Appendix E.02, Bookmark E02 for additional detail. Operators should have ILI contracts that address the following:
  - Tool specifications (including detection/sizing specifications, reliability, and tolerances) (Note: FAQ-68 indicates that tool tolerance must be considered - tool tolerance is based on a percentage of wall thickness.)
  - Operators should specify the threshold for vendor reporting of anomalies. For instance, one operator that was inspected in 2002 specified that the vendor should report all metal loss anomalies greater than 15% WT. The threshold should be appropriate to screen out insignificant or trivial anomalies, while still ensuring that significant anomalies that represent integrity threats are reported. The threshold values should include an allowance for tool tolerance.
  - Tool velocity
  - How ERF is to be calculated. What interaction criterion is to be used? What tolerances are to be applied to defect depth and length? What method is to be used?
  - Anomaly reporting specifications (including the prompt reporting of anomalies that could be immediate conditions or that could represent an imminent pipeline integrity threat)
  - Criteria for data validation and confirming a good tool run. Items to be addressed include:
    - Lost or missing data. What percentage of coverage is acceptable?
    - Failed sensors. How many sensors can fail and the run is still considered acceptable?
  - Deliverable specifications (including both preliminary and final report content, format, use of terminology, etc.)
  - Time limits for all actions required to meet or support discovery and remediation deadlines
  - Procedures for addressing and resolving issues or concerns encountered during the entire ILI process (including preparation, tool run, validation of data, analyzing data, resolving discrepancies, etc.)

- Other aspects of the operator' ILI program include:
  - Validation of assessment results (refer to Appendix E.02, Bookmark E03.)
  - Performance of remaining strength calculations (refer to Appendix E.02, Bookmark E08.)
  - Analyzing tool accuracy (refer to Appendix E.02, Bookmark E11.)
- Hydrostatic test failures must be remediated as well. Refer to Appendix E.02, Bookmark E06 (documentation and analysis of test failures), Appendix E.02, Bookmark E09 (hydrostatic test procedures), Appendix E.02, Bookmark E10 (pressure reversals).

- FAQ-65 clarifies that the use of a prior assessment is allowed in §192.921(e) if the prior assessment meets the baseline assessment requirements in Subpart O and if all remedial actions are carried out for the anomalous conditions referred to in §192.933. For prior assessments, a detailed review of assessment results and remediation of anomalies discovered during the prior assessment should be performed to ascertain if the prior assessment qualifies as a baseline assessment.

E.01.a. Verify a definition of discovery is provided. [§192.933(b)]

E.01.a. Supplemental Guidance:

- Discovery of a condition requiring remediation 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. 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.
- FAQ-58 provides some insight on when an operator should consider that it has discovered a condition that could threaten the integrity of the pipeline. Note that discovery is defined by what information the operator has (or has access to) and not on the amount of time that has elapsed since the assessment. The 180-day requirement is a prescriptive outer limit within which such information must be acquired. Also, greater emphasis should be placed on discovering immediate conditions as soon as possible.
- This protocol section is directed at ensuring that the operator has identified in its integrity management program documentation, procedures, or framework when it considers a condition has been discovered.
- A situation has been observed where the ILI was seriously undercalling defects, and the operator was having the log regraded. It had been over a year since original final report and regrading was not complete. If logs require regrading, then the regrading must be complete within 180 days of the completion of the assessment (the 180-day discovery clock still applies). The operator must obtain sufficient information to discover within 180-days.

E.01.b. Verify a requirement exists to document the actual date of discovery. [§192.933(b)]

E.01.b. Supplemental Guidance:

- The operator has 180 days from the completion of an assessment to finish "discovery" of anomalous conditions. Completion of an assessment occurs when field activities are complete. The operator must make every reasonable effort to complete the discovery phase within 180 days following the assessment, however, in some cases, it may not be practical to complete discovery by that time. The operator must provide the basis for not meeting the 180-day time frame. Refer to the following FAQs:
    - FAQ-34 states that the date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities for in-line inspection tool runs and direct assessments. This would be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with direct assessment is made or the date on which field activities associated with "other technology" for which an operator has provided timely notification are conducted.
- Once the operator has met its own criteria defined in Protocol E.01.a for when sufficient information is accumulated to constitute discovery, the date on which that discovery occurs must be documented in order to ensure that follow-on time frames are met.

- This protocol question is directed at ensuring the operator has a requirement to document the date of discovery. A review of operator records will enable the inspector to determine that the date of discovery has been documented.
- The discovery process must be completed within 180 days of completion of the pipeline's integrity assessment. For ILI assessments, this means 180 days after the date the pig was pulled from the trap. If multiple pig types are used for an entire assessment and the different types of pigs are not run within a few days of each other (i.e., as part of a single set of field activities), then different 180-day timelines apply.
- For DA, this means 180 days after direct examinations are completed. FAQ-232 discusses in more detail the timeframes that apply to discovery of defects when Direct Assessment techniques are used.
- Inspectors should examine the operator's processes and implementation of ILI data validation and verification, the need for verification digs (including when they might not be needed), plotting unity graphs to compare actual vs. called and proper action by operator in response to discrepancies between called and actual defects. A situation has been observed where the ILI was seriously undercalling defects, and the operator was having log regraded. It had been over a year since original final report and regrading was not complete. If logs require regrading, then the regrading must be complete within 180 days of the completion of the assessment (the 180-day discovery clock still applies, the operator must obtain sufficient information to discover within 180-days).
- Note that it is inappropriate to plot corrosion and deformation defects on the same unity chart (as has been observed at one operator).
- FAQ-58 clarifies that discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline.

E.01.c. Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]

E.01.c. Supplemental Guidance:

- 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 Protocol E.02. Refer to the SG for Protocol E.02.d for how to determine required repair time frames for any anomalous conditions that do not meet the special criteria found in §192.933(d)(1) through (d)(3). The anomaly repair schedule requirements in §192.933(d) apply to baseline assessments and subsequent re-assessments required by the gas integrity management rule. Prior internal inspection tool runs do not need to comply with the §192.933(d) criteria unless the pipeline segment inspection is declared to be a baseline assessment as described in §192.921(e).
- A requirement must exist within the operator's program to develop a remediation schedule once conditions that could threaten pipeline integrity have been discovered. It should be observed that this schedule could be subject to change until all conditions are discovered. Conceivably, an operator could discover a condition within a few days of assessment completion. However, for various reasons, the discovery of all conditions may not have occurred until the last day of the 180-day time frame for completion of the discovery phase. The schedule may remain variable until that time. In addition, if the operator has documented an adequate justification for why discovery could not occur until after the 180-day time frame, more time may be necessary to complete the discovery phase and establish the final schedule for remediation activities associated with a particular assessment.
- The burden of proof for extending discovery of a suspected immediate condition should be very high, and the case why delayed discovery does not constitute a safety hazard should be compelling.
- Program documentation is expected to describe how the remediation schedule is prepared, where it can be located, and procedures for updating the schedule.

- The inspector should review conditions identified as immediate threats to covered segments and verify that sufficient effort was made by the operator to promptly discover immediate repair conditions. It is not considered acceptable for an operator to wait until the expiration of the 180-day time is imminent to discover immediate conditions. Operators should proactively discover immediate conditions as soon as possible after enough information is available to do so.
- Also, such information that is in the possession of the ILI vendor is considered to be available to the operator. The operator should have controls in place that require the ILI vendor to immediately report any condition suspected of meeting any of the immediate repair criteria.
- If immediate repair conditions are discovered late in the 180-day time frame, the inspector should verify that sufficient effort was put forth by the operator to discover the immediate threat and that a reasonable basis for the delay exists.
- The scheduling of remediation for immediate repair conditions should take place as soon as possible and the operator's schedule for these conditions should reflect that priority. "As soon as possible" means as soon as it can safely be repaired, and without undue delay. Note that ASME B31.8S-2004, Section 7.2.1, requires that immediate ILI indications be examined within 5 days of discovery. "Examined" is understood to mean excavation and direct examination.
- Operators can delay examination of an immediate defect beyond 5 days, 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)). Operators need not notify PHMSA if they have reduced pressure or taken other action, even if examination is delayed beyond 5 days.
- Inspectors should obtain and review operator documentation justifying delays in examination of immediate repair conditions.
- FAQ-215 states that immediate conditions shall be examined within five days after determination of the condition. This requirement applies to examination of the defect. However, the rule also requires that pressure be reduced once an immediate repair condition is discovered (see §192.933(d)(1)). Pressure reductions should be taken promptly. "Promptly" means as promptly as the pressure reduction can be safely implemented, and without undue delay. In some cases, the operator may have to take time to handle customer demand and critical supply issues, which could be a legitimate reason for some short delays, depending on the circumstances. For instance, interruptions of critical or sole source gas supplies used for heating during winter months could itself represent a safety hazard to customers.

E.01.d. If the operator desires to deviate from the timelines for remediation as provided in §192.933 by demonstrating exceptional performance, verify that the requirements of §192.913(b) have been met and the safety of the covered segment is not jeopardized. [§192.913(c)(2)](See Protocol F.05)

E.01.d. Supplemental Guidance:

- The time frames of §192.933 may be deviated from IF:
  - The operator demonstrates exceptional performance, AND
  - The operator documents the basis for why safety is not jeopardized for the covered segment.
- Protocol E.01.d only applies to operators using the performance-based approach and also qualifies as an "exceptional performer."
- If an operator has elected to demonstrate exceptional performance in accordance with §192.913 of the Rule, then the remediation time frames of §192.933 can be deviated from. In each instance, an operator must document a justification for the safety of the pipeline not being jeopardized. If this basis is not documented, then §192.933 requirements apply as written.
- The inspector should confirm that the operator meets §192.913 requirements before accepting justification for deviation from §192.933 requirements.

E.02 Program Requirements for Identifying Anomalies

Inspect the operator's program to verify that provisions exist 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) Other conditions as specified in ASME B31.8S-2004, Section 7 . [§192.933(c) and §192.933(d)]

E.02 *Supplemental Guidance:*

- All anomalies identified during an assessment must be evaluated and a decision must be made if repair is necessary, monitoring is appropriate, or the condition falls outside the scope of concern based on Rule criteria. Conditions to be repaired fall into 3 basic groups:
    - Immediate repair conditions
    - One-year repair conditions
    - Conditions whose schedule for repair must be determined in accordance with ASME B31.8S-2004, Section 7, Figure 4
- Immediate repair conditions must be accompanied by a reduction in pressure upon discovery, and this reduction should occur as promptly as possible after discovery. "As promptly as possible" means as soon as pressure can be safely reduced, and without undue delay. In some cases, critical supply issues may be an adequate reason for a short delay in reducing pressure. The amount of the pressure reduction is to be determined using ASME B31.G or "RSTRENG" or pressure may be reduced to 80% of the operating pressure (not MAOP) at the time of discovery.
- The remaining strength calculations are limited to use in cases were remaining wall thickness is > 20% of nominal wall thickness, i.e., maximum depth of metal loss is less than 80% WT (d/t<0.8). Any metal loss > 80% WT should be considered an immediate condition as required by Protocol E.02.b.3 or Protocol E.02.b.6.
- The ILI vendor normally calculates remaining strength as part of defect evaluation. What assumptions are used to calculate remaining strength? What method is used?
- Procurement documents between operators and ILI vendors should require that the severe conditions that may affect the integrity of the pipeline be immediately reported to the operator. (See Appendix E.02, Bookmark E02 for more details.)
- 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.
- Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 192.933(d), are promptly identified. Important aspects of tool tolerance affect the following critical integrity management considerations:
    - Defect sizing data for determination of correct repair criteria categorization should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length should be increased by the amount of the tool tolerance). This is especially important for "borderline" anomalies.
    - Defect sizing data used as input into calculations to determine remaining strength of the pipe should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length should be increased by the amount of the tool tolerance).
- Tool tolerance should be considered in such a way as to assure pipeline integrity. This is important because a certain portion of anomalies that are called to be less than a certain repair criterion will in reality meet that repair criterion. For example, out of all the anomalies that are called to be 70% WT, a certain number of them are expected to exceed the 80% WT criterion for an immediate repair condition, based on typical standard MFL tool tolerance of 15%.
- Tool tolerances can also be applied to deformation depth and to orientation. For example, ILI vendors specify the accuracy of their tool in predicting the circumferential location of a defect. A 6% dent of the top of the pipe (between 8 and 4 o'clock) is a one year condition; whereas, a 6%

dent on the bottom of the pipe (between 4 and 8 o'clock) is a monitored condition. Defects located near the 4 and 8 o'clock positions should be evaluated to see if they should be included in the more conservative repair condition.

- Additional guidance of interpreting MFL indications can be found in the technical report Understanding Magnetic Flux Leakage (MFL) Signals from Mechanical Damage in Pipelines - Phase I, September 18, 2007 (Reference: MFL_Signal). The objective of this project is to accurately model MFL signals produced by mechanical damage in pipelines using finite element structural and magnetic modeling techniques. This report summarizes the findings of the first year (Phase 1) of what is anticipated to be a three year study.
- Refer to the following FAQs:
    - FAQ-56 clarifies that the anomaly repair schedule requirements in 192.933(d) apply to baseline assessments and subsequent re-assessments required by the new integrity management rule.
    - FAQ-62 states that monitored conditions must be recorded so that they can be monitored during future integrity management assessments and that they must be repaired if future assessments show changes which cause these anomalies to meet criteria for immediate repair or one-year conditions.
    - FAQ-66 clarifies that the repair schedule requirements in 192.933 apply only to covered segments, recognizing that the operator is responsible for promptly addressing anomalies identified in the other portions of a pigged section in accordance with 192.703(b).
    - FAQ-67 states that reductions in operating pressure are intended to provide an additional safety margin until defects can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced with the defect present.
    - FAQ-68 clarifies that operators are required to integrate relevant information on the condition of the pipeline in making decisions on excavation timing and other mitigative actions. Tool tolerances should be considered as part of the data integration process. Also refer to Supplemental Guidance Appendix E.02, Bookmark E07 for additional discussion regarding tool tolerances and detection uncertainties.
    - FAQ-69 states that the rule specifies that the temporary pressure reduction be determined using ASME B31G or RSTRENG or that pressure must be reduced to a level not exceeding 80 percent of the level at the time the condition was discovered.
    - FAQ-70 clarifies that anomalies identified during pig runs not considered "baseline" or "re-assessments" under the rule must be repaired in accordance with the rule's repair criteria.
    - FAQ-134 clarifies that pressure should be reduced, or the line should be shut down, as soon as practicable once an immediate repair condition is identified.
    - FAQ-135 clarifies segments not in HCAs must be considered when evaluating pipeline after discovering corrosion in a covered segment.

E.02.a. Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. [§192.933(d)(1)]

E.02.a. Supplemental Guidance:

- The operator's integrity management program must have a requirement to take a reduction in operating pressure or shut down the pipeline upon discovery of an immediate repair condition. The definition of what constitutes discovery is examined by Protocol E.01, therefore the operator should have a means of documenting the date an immediate repair condition has been discovered.
- The operator's program documentation, procedures or framework should address the steps to be taken (method) for determining the reduction in pressure and there should be emphasis on the timeliness of these actions.
    - FAQ-215 addresses the requirement that an operator is to examine an immediate repair condition within 5 days of discovery, however pressure reduction is to be taken promptly. "[P]romptly " means as soon as pressure can be safely reduced, and without undue delay.

In some cases, critical supply issues may be an adequate reason for a short delay in reducing pressure, while arrangements are made for alternative supplies, or notifications can be made to customers. For instance, interruption of a sole source gas supply to an LDC during critical winter heating demand could itself be a safety hazard for customers.
    - FAQ-134 also emphasizes the promptness of pressure reduction. Pressure should be reduced, or the line should be shut down, as soon as practicable once an immediate repair condition is identified.
- FAQ-181 addresses requirements for safety related condition reports and notes that in some cases, an immediate repair condition may also require submittal of a safety related condition report.
- FAQ-229 specifies that when determining the proper operating pressure to reduce to, an appropriate safety factor must be applied.
    - The least restrictive safety factor specified in §192.111 is 0.72. This safety factor is also built in to B31G and RSTRENG for determining a safety operating pressure. This safety factor should be used unless the need for a more restrictive factor is indicated.
    - Higher temporary operating pressures may be justified by the operator using empirical data as long as the justification demonstrates that the defect will not grow to a size that results in the predicted burst pressure being less than 1.1 times the temporary operating pressure.
    - Since the temporary pressure can remain in force for 365 days, growth rate determinations must be performed based on the time from the assessment to the end of the 365-day term of reduced pressure.

E.02.b. Verify provisions exist to classify and categorize anomalies meeting the following criteria:

i. Immediate Repair Conditions (Conditions requiring immediate remediation actions)
    1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP; [§192.933(d)(1)]
    2. A dent having any indication of metal loss, cracking, or a stress riser; [§192.933(d)(1)]
    3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action. [§192.933(d)(1)]
    4. Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding; [ASME B31.8S-2004, Section 7.2.1]
    5. All indications of stress corrosion cracks; [ASME B31.8S-2004, Section 7.2.2]; or
    6. Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. [ASME B31.8S-2004, Section 7.2.3]

ii. One-Year Conditions (Conditions requiring remediation within one year of discovery).

    1. A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; [§192.933(d)(2)] or,
    2. A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld. [§192.933(d)(2)]

iii. Monitored Conditions (Conditions which must be monitored until the next assessment).

    1. A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe; [§192.933(d)(3)]
    2. A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; [§192.933(d)(3)]or,
    3. A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded. [§192.933(d)(3)]

E.02.b. Supplemental Guidance:

- ASME B31.8S-2004, Section 7, has extensive information regarding various types of indications and which of these require immediate attention. The Rule invokes ASME B31.8S-2004, Section 7, therefore the operator must follow the requirements identified in this section of the standard. It is expected that the operator's integrity management program documentation or procedures, either directly or by reference, include all requirements of ASME B31.8S-2004, Section 7.
    - The remaining strength calculations are limited to use in cases were remaining wall thickness is > 20% of nominal wall thickness, i.e., maximum depth of metal loss is less than 80% WT (d/t<0.8). FAQ-241 clarifies this point. Any metal loss > 80% WT should be considered an immediate condition as required by Protocol E.02.b.3 or Protocol E.02.b.6, unless there are very strong technical reasons to respond to the condition less urgently.
- The special criteria for immediate repair conditions found in §192.933(d)(1) are to be found directly, or by reference, in the operator's program documentation, procedures, or framework. Anomalies meeting these criteria must result in a reduction in operating pressure using the methods identified in §192.933(1). The program documentation should make the connection of the criteria to the pressure reduction requirement. The 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:
    - Where the predicted failure pressure is less than or equal to 1.1 times MAOP.
    - Where there is a dent with accompanying metal loss, cracking, or a stress riser.
    - Where engineering judgment by technical evaluators or management indicate that the condition must be immediately dealt with.
    - Where metal loss is present on the longitudinal seam of low frequency ERW or lap welded pipe.
    - Where there is any indication of Stress Corrosion Cracking, or
    - Where there is any indication that the condition might result in rupture of the pipeline and require immediate action.
- FAQ-241 notes that B31G and RSTRENG are not valid for situations with metal loss exceeding 80 percent of wall thickness (see Figure 1-2 in B31G, which requires "repair or replace" for conditions involving wall loss greater than 80 percent).
- The special criteria for one-year repair conditions found in §192.933(d)(2) are to be found directly, or by reference, in the operator's integrity management program documentation, procedures, or framework. This program requirement should indicate that the one-year conditions are to be scheduled within one year from the date of discovery. The one-year repair conditions as defined by §192.933(d)(2)(i-ii) are as follows:
    - 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.
    - 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.
- The special criteria for monitored conditions found in §192.933(d)(3) are to be found directly, or by reference, in the operator's integrity management program documentation, procedures, or framework. Some conditions do not warrant repair, but instead require monitoring to determine if their status changes such that they present an integrity concern. The following criteria from §192.933(d)(3) is to be used in designating monitored conditions:
    - 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.
    - 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.

    - 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.
- Note that discovery date is the subject of Protocol E.01.b.
- 49 CFR 192.309 discusses repair criteria for new construction of transmission lines. Subsection 192.309(b) in particular discusses repair criteria for dents in pipeline operating above 20% SMYS and 40% SMYS. Subsection 192.309(b)(3) only applies to pipe operating > 40% SMYS. While the deformation (dent) size criteria are similar, 933(d) applies to all transmission pipe in HCAs and 309(b)(3) only applies to pipeline operating >40% SMYS. Overlaying 192.933(d) repair criteria onto the 192.309(b) criteria, it can be seen that the dent repair criteria in 192.933(d) are more strict in their application than the 192.309(b)(3) dent criteria for pipelines operating between 20% and 40% of SMYS. The basis for this is that the 192.933(d) criteria are intended to afford extra protection to pipelines in HCAs, whereas the 192.309(b) criteria apply to all new construction pipelines. Operators must repair (or otherwise remediate) such construction defects, even though the defects did not meet the repair criteria in 192.309(b) at the time of construction.

E.02.c. Verify provisions exist to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk or integrity assessments for any change in their status that would require remediation. [§192.933(d)(3)]

E.02.c. Supplemental Guidance:

- Protocol E.02.c. examines the process for monitoring conditions that do not require scheduled repair. The inspector should determine how monitored conditions are identified and where the report is located.
- Integrity Management program procedures must address the activities necessary to monitor the status of these conditions during subsequent risk assessments and integrity assessments. It is expected that an identification process has been developed to tag these conditions.
- This process should evaluate the conditions since changing conditions and risk factors could potentially affect their status. There should also be a process by which these conditions are re-reviewed, including the frequency of that review, for determination of needed repair.

E.02.d. Verify that program requirements exist to meet the provisions of ASME B31.8S-2004, Section 7, Figure 4 for scheduling and remediating any other threat conditions that do not meet the classification criteria of Protocol E.02.b, above. [§192.933(c)]

E.02.d. Supplemental Guidance:

- ASME B31.8S-2004, Section 7, Figure 4, provides a graph that instructs the operator how to determine required repair time frames for any anomalous conditions that do not meet the special criteria found in §192.933(d)(1) through (d)(3).
- By using current operating pressure as a % of SMYS, the operator can determine which plot on the graph applies to its pipeline. Then by determining predicted failure pressure (Pf) for the anomaly in question and using the ratio of Pf to the MAOP for the pipeline, the time by which the anomaly must be repaired can be determined. This method should be prescribed in the operator's integrity management program and it should be noted that it applies to all anomalies that do not meet the special criteria in §192.933(d).
    - Note: The formulas in the following table model the curves depicted in ASME B31.8S-2004, Section 7, Figure 4. Either these formulas or Figure 4 may be used for determination of the required response time for anomalies.

Timing for Scheduled Responses

Pipeline Operating Stress	Formula to Find Response Time	Not to Exceed Response

Level	"Years"	Timeframes
At or Above 50% SMYS	Years = (Pf / MAOP - 1.1) / 0.029	10 Years
At or Above 30% up to 50% SMYS	Years = (Pf / MAOP - 1.1) / 0.06	15 Years
Less than 30% SMYS	Years = (Pf / MAOP - 1.1) / 0.11	20 Years

- Concerns have been raised about the applicability of ASME B31.8S-2004, Section 7, Figure 4 when considering pipeline that is operating at pressures that are less than 30 - 50% of SMYS. The concern is that pipeline operating at these lower pressures could have a Pf to MAOP ratio of 1.1 - 1.3 and still require relatively quick response times. In these cases, the pipeline would have only a very thin wall left, meriting the quicker response times. Therefore Figure 4 must still be used to determine the response schedule in these cases.

E.03 Operator Response when Timelines for Evaluation and Remediation Cannot be Met

Verify that provisions exist to respond appropriately when the operator is unable to meet time limits for evaluation and remediation. [§192.933(a)].

E.03 *Supplemental Guidance:*

- The operator should have integrity management program requirements that ensure compliance with remediation time frames required by the special criteria of §192.933(d)(1) through §192.933(d)(3) or, if not applicable, then using the criteria found in ASME B31.8S-2004, Section 7, Figure 4.
- There are conditions, such as inclement weather or other natural phenomena that can impact the ability of an operator to respond within the time frames that they have scheduled in order to meet the Rule. This Protocol is directed at inspecting the operator's integrity management program to determine that it has in place those necessary requirements to ensure that the response to these situations meets the Rule.
- Review of the records and justifications where these repair dates cannot be met is the subject of Protocol E.04.
- FAQ-69 clarifies that the rule permits a 20 percent reduction in pressure as an adequate interim measure for immediate repair conditions. The rule specifies that the temporary pressure reduction be determined using ASME B31G or RSTRENG or that pressure must be reduced to a level not exceeding 80 percent of the level at the time the condition was discovered.

E.03.a. Verify a requirement exists to take a temporary operating pressure reduction or other action that ensures safety of the covered segment in the event the operator is unable to respond within the timeframes required by §192.933. [§192.933(a)]

i. Verify a requirement exists to determine the appropriate pressure reduction using ASME B31G, or "RSTRENG", or reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered. [§192.933(a)]
ii. Verify a requirement exists that when a pressure reduction is to exceed 365 days, a documented technical justification is developed that explains the reason for remediation delay and demonstrates continuation of the reduction will not jeopardize pipeline integrity. [§192.933(a)]

E.03.a. Supplemental Guidance:

- An operator must either take a temporary pressure reduction or take some other action to ensure safety if a repair condition cannot be resolved by time frames required by the rule. There is no

specification in the Rule as to what constitutes this "other action", however the basis for continued safety as a result of this action should be convincing. The choices for this other action can depend on issues such as where the anomaly is located, the nature of the defect, operating history, etc.

- NOTE: As specified in §192.933(d), the option to take "other action to ensure safety" does not apply to immediate repair conditions. Refer to Protocol E.02.a. Operators must either take a pressure reduction or shut down the line in response to an immediate condition.
- The operator's program documentation must specify the requirement to take a pressure reduction or take another action. The operator should describe the process by which that other action is determined.
- When a temporary pressure reduction is opted for by an operator who cannot meet a remediation schedule, the method of acceptably determining that reduction has been defined in the Rule. A pressure reduction is also mandatory when an immediate repair condition has been discovered as presented in Protocol E.02. The method of determining the appropriate pressure reduction is the same, but the entry condition is different. The choices for determining the proper pressure reduction are:
    - ASME B31G
    - RSTRENG
    - 80% of operating pressure at the time the condition was discovered (not MAOP).
- The 80% reduction application requires the date the unrepaired anomaly was discovered and knowledge of the operating pressure on that date. The operator's program documentation should describe how the pressure reduction determination is performed.
- The operator may continue a reduced pressure for a period of 365 days.
- To extend the pressure reduction beyond 365 days, the operator must document the basis of why the integrity of the pipeline is not jeopardized and explains the reasons for remediation delay. A requirement to document this justification must exist in the operator's integrity management program documentation, procedures, or framework. No information is presented in the Rule as to what constitutes an acceptable basis for continued pressure reduction, but the operator should provide a compelling basis that is technically sufficient.
- There is no requirement for notification of this extended pressure reduction to PHMSA or the State or local pipeline safety authority as applicable.

E.03.b. Verify a requirement exists to document the justification, when an evaluation and remediation activity cannot be completed within established timeframe requirements, that includes the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety. [[§192.933(a) and §192.933(c)]

E.03.b. Supplemental Guidance:

- Any time a remediation schedule cannot be met, the operator must document:
    - why the specified remediation schedule cannot be met, and
    - why the changed schedule will not jeopardize public safety
- There is no indication in the Rule what an adequate justification would be, but the inspector should be presented with a technically sound basis.
- The requirement to document this justification must be part of the operator's integrity management program documentation, procedures, or framework.

E.03.c. Verify a requirement exists to notify PHMSA in accordance with §192.949 and the State pipeline safety authority, if applicable, when:

i. the operator cannot meet the evaluation and remediation schedule and cannot provide a temporary reduction in operating pressure or other action [§192.933(a)(1) and §192.933(c)], and
ii. a pressure reduction exceeds 365 days. [§192.933(a)(2)]

The notification is to include the documented justification under protocols E.03.a and E.03.b.

E.03.c. Supplemental Guidance:

- PHMSA must be notified when the operator:
    - Cannot meet a required remediation schedule, AND
    - Cannot respond to that failure by either reducing pressure or taking another action to ensure safety of the pipeline.
- PHMSA must also be notified if a pressure reduction exceeds 365 days.
- This notification must be made in accordance with §192.949.
- The operator's IM procedures must address the §192.949 notification requirements and development of the necessary justification.
- When it has jurisdictional authority, 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.

E.04 Record Review for Discovery, Repair and Remediation Activities

Inspect operator repair and remediation records to verify that remediation activities have been conducted in accordance with program requirements. [§192.933]

E.04 *Supplemental Guidance:*

- Numerous records are generated by the operator in the process of performing remediation activities to meet IM Program requirements. The focus of this protocol item is to review those records generated as evidence that the operator is meeting remediation requirements in the Rule and to demonstrate that the operator's program requirements for remediation are being executed properly by those charged with implementing the integrity management program.
- Records and documentation for review includes the following activities or documents:
    - ILI Reports (both preliminary and final)
    - DA results
    - Review of assessment results and the discovery of anomalies and their timeliness
    - Nature (type) and size of anomalies
    - "Dig lists"
    - The operator's remediation schedule
    - Actions taken to repair or otherwise remediate discovered conditions
    - Repair records
    - 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.
    - The evaluation and remediation steps taken for anomalous conditions,
    - The documented justification for continuing a pressure reduction beyond 365 days, and
    - Documents indicating when a remediation activity has been completed.
- Calculation of safe operating pressures, and thus determining appropriate repairs, poses special concerns for pipe that is grandfathered or waivered to operate at higher pressures than the design pressure its current class location would allow. This includes:
    - all pipe grandfathered to operate at greater than 72% SMYS,
    - pipe that operates above 72% SMYS as a result of a waiver, and
    - pipe for which a waiver approved continued operation without pressure reduction after a class location change.

  The reason is that the standard methods of calculating allowable pressure (e.g., ASME B31G, RSTRENG) incorporate the design factors from §192.111, and calculations using these tools could show safe operating pressures below the design pressure calculated in accordance with §192.105. Inspectors should pay particular attention to instances in which repairs are needed in covered segments that are grandfathered or operating under waivers. Inspectors should question operators concerning how they have designed an appropriate repair. Note that use of the design factors

specified in §192.105 (e.g. repairing to class 3 criteria even though a waiver was issued to allow continued operation at class 2 pressures) is one acceptable means of addressing this concern.

- There are numerous FAQs related to records and implementation reviews:
    - FAQ-56 states that anomaly repair requirements in 192.933 do not apply to old assessments unless it is being used as a baseline assessment under the "prior assessment" provision.
    - FAQ-58 states that discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline.
    - FAQ-62 states that a schedule for remediation of monitored conditions is not required, but they must be monitored for any changes that would result in the need to schedule remediation.
    - FAQ-65 states that old assessments conducted before December 17, 2002 may only be credited as a "prior baseline assessment" after all anomalies have been remediated per 192.933.
    - FAQ-66 states that even though §192.933 only applies to covered segments, operators must repair anomalies discovered in non-covered segments in accordance with their O&M manual.
    - FAQ-67 states that pressure reduction must be based on actual recent operating pressure, (not MAOP).
    - FAQ-68 states that tool tolerances must be considered in evaluating anomalies against the repair criteria. Also refer to Supplemental Guidance Appendix E.02, Bookmark E4 - Section E.4, E.5 and E.6 for additional discussion on tool tolerances and detection uncertainties.
    - FAQ-69 states that a 20 percent pressure reduction is an adequate pressure reduction for immediate repair conditions.
    - FAQ-70 clarifies that any data collected, whether "baseline", "reassessment", or from other sources must be acted upon when the information is available.
    - FAQ-134 states that pressure should be reduced, or the line should be shut down, as soon as practicable once an immediate repair condition is identified.
    - FAQ-135 states that that operators who identify corrosion in a covered segment that could adversely affect the integrity of the line must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.
    - FAQ-224 states that §192.917(e)(5) requires that an operator who finds corrosion on a covered pipeline segment "must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics."
    - FAQ-225 states that operators may find problems in non-covered segments while performing assessment of covered segments and must take appropriate actions.

E.04.a. Verify a prioritized schedule exists for evaluation and remediation of anomalies identified during assessment or reassessment activities. The prioritized schedule must document which of the criteria specified in §192.933(d) and/or ASME B31.8S-2004 were used as the basis for the schedule. [§192.933(c) and §192.933(d)]

E.04.a. Supplemental Guidance:

- Inspect operator records for a schedule for evaluation and remediation of anomalies resulting from either the baseline assessment or a following reassessment. Each condition that meets the criteria for an anomaly requiring repair must have an associated date scheduled for completion.
- The schedule must be consistent with the criteria of §192.933(d) or it must have been determined using the information in ASME B31.8S-2004, Section 7.
- The schedule should indicate the source of the priority (either the criteria in §192.933(d) or ASME B31.8S-2004, Section 7, Figure 4) and should indicate priority for immediate conditions.

- The schedule should be used to track completion of remediation activities and demonstrate compliance with required timeframes.

E.04.b. Verify anomaly discovery was documented within 180 days of completion of the assessment or reassessment, or else that compliance with the 180-day period was impracticable. [§192.933(b)]

E.04.b. Supplemental Guidance:

- Inspection should include a review of operator records to confirm that discovery occurred within 180 days of completion of the assessment. Each anomaly should have an associated discovery date documented.
- 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.
    - FAQ-34 states that the date an assessment is considered complete is the date on which final field activities related to that assessment are complete (not including repairs).
- Inspection should confirm that immediate repair conditions received priority in their discovery by both the vendor (if used) and the operator.
- If discovery did not occur within the 180-day time frame, the operator must document why it was impractical to do so. This justification is not filed as a notification to PHMSA, but should be available for review.
- Operators may not delay discovery in cases when the ILI log must be regraded. The operator must obtain sufficient information to discover anomalies (including the regrading of the logs, if required), within 180 days of completion of the assessment.

E.04.c. Verify any remediation activities taken are sufficient to ensure that the anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. [§192.933(a)]

E.04.c. Supplemental Guidance:

- Inspection should include a review of operator remediation records to confirm that any repairs undertaken are sufficiently robust to prevent failure due to that condition until the next assessment of the pipeline. This will involve some judgment on the part of the inspector, but repairs that do not appear to have been performed properly, such as using unqualified personnel, could be cause to reject the repair work.
- It should be expected that the date for the next assessment has been determined in order to reach the conclusion that the repair was accomplished in a manner that restores pipeline integrity to a condition that will not be jeopardized before the next scheduled assessment.
- The Pipeline Repair Manual (AGA, Catalog Number L51716, 1994) presents a catalog of known pipeline repair techniques, and discusses the various types of pipeline defects that lend themselves to being repaired in-service. A matrix is provided to match defects in need of repair with appropriate repair methods.
- Note that the repair requirements of §192.713(a)(2) are also applicable to segments, both covered and non-covered, operating at pressures greater than 40% SMYS.

E.04.d. Verify, for any immediate repair anomalies, a temporary pressure reduction is taken by the operator on the pipeline and the reduced pressure is determined in accordance with ASME B31G, or "RSTRENG", or that the reduced pressure does not exceed 80% of the level at the time the condition was discovered. [§192.933(a)]

E.04.d. Supplemental Guidance:

- Inspection should include a review of operator records to determine that pressure reduction determinations have been properly accomplished.

- If the pressure reduction is calculated, a review of the calculations could be appropriate to confirm adequacy and use of the proper methods. If the pressure reduction is 80% of operating pressure at the time of discovery, the date of discovery and operating records or logs may need to be consulted to confirm the proper pressure reduction was taken.
- FAQ-229 discusses the appropriate safety factors that must be used in determining the proper pressure reduction. A 0.72 safety factor would be normally expected unless conditions indicate a more restrictive safety factor is necessary or if the operator demonstrates through analysis of empirical defect growth rate data (or conservative defect growth rate assumptions) that a higher pressure is acceptable.
- See Protocol E.02.a which discusses pressure reductions.

E.04.e. Verify immediate repair conditions have been evaluated and remediated on a schedule established in accordance with the provisions of ASME B31.8S-2004, Section 7. [§192.933(d)(1)]

E.04.e. Supplemental Guidance:

- Inspection should include a review of operator records to confirm that immediate repair conditions have been identified and remediated in accordance with ASME B31.8S-2004, Section 7. The standard has specific direction with regard to what constitutes an immediate condition and how long it should take an operator to declare one exists.
- The 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:
    - Where the predicted failure pressure is less than or equal to 1.1 times MAOP.
    - Where there is a dent with accompanying metal loss, cracking, or a stress riser.
    - Where engineering judgment by technical evaluators or management indicate that the condition must be immediately dealt with.
    - Where metal loss is present on the longitudinal seam of low frequency ERW or lap welded pipe.
    - Where there is any indication of Stress Corrosion Cracking, or
    - Where there is any indication that the condition might result in rupture of the pipeline and require immediate action.

E.04.f. Verify any pressure reduction taken has not exceeded 365 days from the date of discovery unless:

i. a technical justification has been developed that explains the reason for remediation delay and demonstrates that continuation of the pressure reduction will not jeopardize the integrity of the pipeline, and

ii. PHMSA and the State pipeline safety authority, if applicable, have been notified in accordance with §192.949. [§192.933(a)]

E.04.f. Supplemental Guidance:

- Inspection should include a review of operator records to confirm that when a pressure reduction has been taken, it has not been in place as a mitigative measure for longer than 365 days unless a basis for continuation has been developed. This basis should demonstrate why the pipeline remains safe under the extended pressure reduction.
- The date for the initial pressure reduction should be available in the records in order to be able to track the 365-day time frame.
- Pressure reductions that exceed 365 days require notification to PHMSA and the State pipeline safety authority, if applicable.

E.04.g. Verify that remediation activities were completed in accordance with scheduled timeframes. [§192.933(c) and §192.933(d)]

E.04.g. Supplemental Guidance:

- Inspection should include a review of operator records to confirm that scheduled remediation activities did, in fact, occur by the dates they were scheduled. Typically, this involves reviewing repair records to determine actual repair completion dates and comparing to the remediation schedule.

E.04.h. Verify that anomalies meeting any of the criteria of §192.933(d)(3) as "monitored conditions" are evaluated during subsequent risk and integrity assessments to identify any change that may require remediation and that any required remediation is scheduled and implemented in accordance with the applicable requirements of §192.933 and ASME B31.8S-2004. [§192.933(d)]

E.04.h. Supplemental Guidance:

- Inspection should include a review of an operator's program to verify that anomalies meeting any of the criteria of §192.933(d)(3) as "monitored conditions" are evaluated during subsequent risk assessments and integrity assessments to identify any change that may require remediation and that any required remediation is scheduled and implemented in accordance with the applicable requirements of §192.933 and ASME B31.8S-2004.
- Monitored conditions must be reevaluated during subsequent risk assessments. Examples of conditions that might be identified that could result in the need to remediate the monitored condition include, but are not limited to:
    - Corrosion growth rates at nearby locations are determined to be greater than originally assumed.
    - New threats to the pipeline segment are identified that could interact with the monitored condition and cause failure before the next assessment.
    - Identification of previously unknown encroachment could cause a small dent that was previously thought to be construction damage to be re-interpreted as third party damage.
- Monitored conditions must be re-evaluated during subsequent integrity assessments. If the defect has not grown to a size that meets any repair criteria, it must continue to be monitored. Defect growth should be analyzed and considered in establishing subsequent re-assessment intervals. Also, these monitored conditions serve as validation checks for the re-assessment. If a known monitored conditions is not called (or significantly under-called) by the new assessment, the validity of the assessment may be questionable.
- Review of operator records should confirm that monitored conditions have been tracked and re-reviewed at subsequent assessments (if more than a baseline assessment has been performed.)

E.04.i. Verify any remediation activities that have not been completed in accordance with §192.933 timeframes, and the operator has not provided safety through a temporary pressure reduction:

i. have technical justifications that include the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety, and

ii. have been reported to PHMSA and appropriate State authorities in accordance with the requirements of §192.933(c) of the rule. [§192.933(c)]

E.04.i. Supplemental Guidance:

- Inspection should include a review of operator records to confirm that the required notifications have been submitted to PHMSA or the State pipeline safety authority (as applicable) when the remediation schedule cannot be met and safety cannot be ensured by either reducing operating pressure or some other appropriate action.

Protocol Area F. Continual Evaluation and Assessment

- F.01 Periodic Evaluations
- F.02 Reassessment Methods
- F.03 Low Stress Reassessment
- F.04 Reassessment Intervals
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F.01 Periodic Evaluations

Verify the operator conducts a periodic evaluation of pipeline integrity based on data integration and risk assessment to identify the threats specific to each covered segment and the risk represented by these threats. [§192.917 and §192.937(b)]

F.01 *Supplemental Guidance:*

- Verify that the operator's IMP requires the completion of periodic evaluations and reassessments of covered segments after completing the baseline integrity assessment.
- An operator must 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.
- 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.
    - FAQ-205 states that operators should use the best information that they have available in performing the data integration and analysis.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F1 - Protocol F.1.

F.01.a. Verify that periodic evaluations are conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917. The evaluation must consider the following: [§192.937(b) and 192.917]

i. Past and present assessment results
ii. Data integration and risk assessment information [§192.917]
iii. Decisions about remediation [§192.933]
iv. Additional preventive and mitigative actions [§192.935]

F.01.a. Supplemental Guidance:

- The inspector should verify that the data from the entire pipeline is considered and not just data from covered segments. Furthermore, an operator is only required to gather and integrate existing data about its pipeline system, i.e., the data does not have to be created if it does not exist.
- The inspector should verify that the periodic evaluations 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. Also, verify that the evaluation assumes the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. [Refer to §192.917(e)(2)]

- FAQ-81 states that when performing continual evaluation the operator must consider all information relevant to determining risk associated with pipeline operation in HCAs.
- Refer to Supplemental Guidance Appendix C.02, White Paper, Data Gathering and Integration.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F1a - Protocol F.1.a.

F.01.b. Verify that periodic evaluations of data are thorough, complete, and adequate for establishing reassessment methods and schedules. [§192.937(b)]

F.01.b. Supplemental Guidance:

- Review the IM Program to determine if it contains requirements to conduct periodic integrity evaluations that are technically rigorous, justifiable and adequate for making integrity related decisions.
- Review a sampling of completed periodic evaluations to check for technical justification and completeness.
- Refer to Protocol A.06 regarding the need to periodically review data for identification of new, or changes to HCAs.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F1b - Protocol F.1.b.

F.01.c. Verify that an appropriate interval is established for performing required periodic evaluations of threats and pipeline conditions following completion of the baseline assessment. [§192.937(b)]

F.01.c. Supplemental Guidance:

- The rule does not require that periodic evaluations be conducted within a specific maximum interval as it does for reassessments. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. Inspectors should note that there are 2 potentially contradictory statements concerning risk re-evaluation in ASME B31.8S-2004, Section 5.8: "A specified period defined by the operator shall be established for a system wide risk re-evaluation but shall not exceed the maximum required interval". It goes on one sentence later to state "The frequency of the system wide re-evaluation must be at least annually but may be more frequent based on the frequency and importance of data modifications." PHMSA generally expects that the HCA review and risk analyses will be re-evaluated at a minimum on an annual basis (refer to FAQ-234). This is to provide operators with sufficient time to identify changes to HCAs and incorporate them into their plans within one year of their identification. More frequent review may be necessary if conditions warrant. Refer to Protocol A.06 for expectations related to changes to HCAs and FAQs related to annual re-evaluation expectations.
- An operator must base the frequency of the evaluations on risk factors specific to its pipeline.
- The occurrence of a time-dependent failure requires immediate evaluation of the re-assessment interval (ASME B31.8S-2004, Table 3, Note 1).
- In addition to a regularly scheduled periodic evaluation interval, the operator should conduct periodic evaluations of its pipeline as needed in response to certain events, in order to assure that pipeline integrity threats are promptly identified. The operator, therefore, should have controls in place that identify those factors/events that should initiate an immediate evaluation of pipeline integrity.
- After having reviewed the periodic evaluation schedule the inspector should make a qualitative judgment regarding the adequacy of the schedule and its basis.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F1c - Protocol F.1.c.

F.01.d. Verify that the operator periodically reviews the evaluation results to determine if the new information warrants changes to reassessment intervals and/or methods, and makes changes as appropriate. [§192.937]

F.01.d. Supplemental Guidance:

- Verify that the operator periodically reviews the processes and risk assessment methods used to develop the evaluations to ensure they continue to yield relevant, accurate results consistent with the objectives of the operator's overall integrity management program.
- Adjustments and improvements to the risk assessment methods will be necessary as more complete and accurate information concerning pipeline system attributes and history become available.
- Identify relevant changes to the pipeline system and verify that this new information was evaluated for potential impact on evaluation results (i.e., reassessment intervals and methods). Determine if the conclusions regarding the potential impact were appropriate.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F1d - Protocol F.1.d.

F.02 Reassessment Methods

Verify that the approach for establishing the reassessment method is consistent with the requirements in §192.937(c). [§192.937(c) and §192.941]

F.02 *Supplemental Guidance:*

- The inspector should review the IMP to verify that the approach used to determine the reassessment method is consistent with ASME B31.8S-2004, Section 6.
- Refer to guidance in Protocol B.01.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F2 - Continual Evaluation and Assessment.

F.02.a. Verify that one or more of the following assessment methods (depending on the applicable threats) are specified:

i. An internal inspection tool(s) capable of detecting corrosion and any other threats that the operator intends to address using this tool(s). The process must follow ASME B31.8S-2004, Section 6.2, in selecting the appropriate inspection tool. [§192.937(c)(1)]
ii. A pressure test conducted in accordance with Subpart J. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939. Pressure test is appropriate for threats as defined in ASME B31.8S-2004, Section 6.3. [§192.937(c)(2)]
iii. Direct assessment – refer to Protocol D. [§192.937(c)(3)]
iv. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the pipe. If other technology is the method selected, the process should require that the operator notify PHMSA at least 180 days before conducting the assessment, in accordance with §192.949. Also, verify that notification to a State or local pipeline safety authority is required 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. [§192.937(c)(4)]
v. Confirmatory direct assessment when used on a covered segment that is scheduled for a reassessment period longer than seven years. Refer to Protocol G. [§192.937(c)(5)]
vi. If the operator is using "low stress reassessment" method, evaluate the process using Protocol F.03.

F.02.a. Supplemental Guidance:

- Refer to Supplemental Guidance for Protocol B.01.
- FAQ-187 states that direct assessment is an acceptable assessment method, but needs to be used only in situations where it is applicable.
- An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify the maximum reassessment intervals in accordance with §192.939. See Protocol F.04 regarding the reassessment interval. The test pressures specified in Subpart J are typically less than the pressures specified in ASME B31.8S-2004, Section 5, Table 3, that are needed to justify the maximum reassessment intervals.
- Use of a spike test, alone, as an assessment method would constitute "other technology". Operators planning to use "other technology" to perform assessments must notify PHMSA (and/or a state regulator if applicable) at least 180 days in advance. 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 would be required.
    - FAQ-141 states that use of a spike test alone would constitute "other technology".
- A 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. Refer to Supplemental Guidance Appendix F.04, White Paper, CDA and Reassessment Intervals, and the following FAQs for more guidance:
    - FAQ-133 states that 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.
    - FAQ-216 states that all covered segments must be assessed at least every 7 years.
    - FAQ-228 states that performance of a CDA does not extend the interval until the next primary reassessment.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F2a - Protocol F.2.a.

F.02.b. Review the methods selected for reassessments and verify that they are appropriate for the identified threats.

F.02.b. Supplemental Guidance:

- Review a sample of covered segments and verify that the reassessment method selected is consistent with the requirements of the operator's IMP and ASME B31.8S-2004, Section 6, based on the threats applicable to that segment.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F2b - Protocol F.2.b.

F.03 Low Stress Reassessment

For pipelines operating at < 30% SMYS, the operator may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, verify that the operator addresses the following requirements [§192.941]:

F.03 *Supplemental Guidance:*

- This provision recognizes the relatively low risk posed by these pipelines and the likelihood that failures will result in leakage rather than rupture. Operators who implement this low-stress reassessment option also have the option of performing CDA.
- Low stress reassessments, like CDAs, are interim assessment methods, not primary assessment methods.

- Reassessment for these low-pressure pipelines by the other methods allowed by the rule (i.e., pressure test, internal inspection, direct assessment) is required only every 20 years, the maximum interval allowed by ASME B31.8S-2004, unless the periodic evaluation determines that a shorter interval is appropriate.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F3 - Protocol F.3.

F.03.a. Verify that the operator completes a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method. [§192.941(a)]

F.03.a. Supplemental Guidance:

- The rule requires that a baseline assessment must be completed on a segment before the low stress reassessment method can be performed as a reassessment. For operators choosing to use the low-stress reassessment method, the inspector should review documents that show a completed and satisfactory baseline assessment.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F3a - Protocol F.3.a.

F.03.b. If used to address external corrosion, verify that the operator has incorporated the following:

i. If the pipe is cathodically protected, electrical surveys (i.e., indirect examination tool/method) must be performed at least every 7 years. The operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for covered segments. This evaluation must consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)]
ii. If the pipe is unprotected or cathodically protected where electrical surveys are impractical, the operator must require (1) the conduct of leakage surveys as required by §192.706, at 4-month intervals; and (2) the identification and remediation of areas of active corrosion every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)]

F.03.b. Supplemental Guidance:

- Given certain field conditions, electrical surveys may be impractical. Such conditions may include pavements (reinforced), stray current areas possibly near electric ROW or electrified railways, and casings.
- Follow up investigation would be required if areas of concern are identified. Follow up investigation could include: where practicable, close interval surveys; or for coated pipe, selective use of voltage gradient devices.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F3b - Protocol F.3.b.

F.03.c. If used to address internal corrosion, verify that the operator has incorporated all of the following:

i. Gas analysis for corrosive agents must be performed at least once each calendar year. [§192.941(c)(1)]
ii. Periodic testing of fluids removed from the segment must be conducted. At least once each calendar year the operator must test the fluids removed from each storage field that may affect a covered segment. [§192.941(c)(2)]
iii. At least every seven (7) years, the operator must integrate data from the analysis and testing required by c.i and c.ii above with applicable internal corrosion leak records, incident reports, and test records, and define and implement appropriate remediation actions. [§192.941(c)(3)]

F.03.c. Supplemental Guidance:

- Review periodic gas analysis and fluid analysis from segments and storage fields to determine if corrosive agents were present.
- If corrosive agents were present in the analysis review the operator's actions to address the problem.
- Review the operator's data integration and verify that appropriate analysis and remediation activities were performed.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F3c - Protocol F.3.c.

F.04 Reassessment Intervals

Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S-2004. [§192.937(a), §192.939(a), §192.939(b), §192.913(c), and ASME B31.8S-2004, Section 5, Table 3]

F.04 *Supplemental Guidance:*

- Review the operator's IM Program to determine if each segment that could affect HCAs is scheduled for a reassessment (if it has already had a baseline assessment), or that the process requires that a reassessment be scheduled upon completion of the baseline assessment.
- Verify that the process assures that reassessment intervals are based on the results of the periodic evaluation and do not exceed the values specified in ASME B31.8S-2004, Table 3.
- FAQ-236 states that operators may use straight-line interpolation to determine acceptable intervals between the 5, 10, 15, and 20 year intervals listed in ASME B31.8S-2004, Table 3. In no case must operators reassess more frequently than once every seven years unless such frequent reassessments are determined necessary by risk assessment.
- FAQ-28 states that the risk posed by each pipeline segment covered by the rule must be considered in scheduling reassessments.
- ASME B31.8S-2004, Table 3 would indicate that for low stress pipe, a Subpart J pressure test would require a 5-year reassessment interval. However, PHMSA position is that reassessment is not required in less than seven years as long as test pressures are at least as high as required by Subpart J, unless the operator's risk assessment indicates a need to do so. Pressure tests must be conducted at pressures in ASME B31.8S-2004, Section 6.2, if reassessment intervals longer than seven years are to be used. In that case, a confirmatory direct assessment or low-stress reassessment (as appropriate) must be conducted at seven years. In no case may the interval between assessments (including confirmatory direct assessment and low-stress reassessment) exceed seven years. Refer to FAQ-207 and FAQ-236.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F4 - Protocol F.4.

F.04.a. Verify that the operator reassesses covered segments on which a baseline assessment was conducted during the baseline period specified in subpart 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the reassessment evaluation (refer to Protocol F.01) indicates an earlier reassessment. [§192.937(a)]

F.04.a. Supplemental Guidance:

- 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 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.
- Refer to the following FAQs regarding reassessment intervals:
  - FAQ-40 states that assessments must be performed at intervals no longer than 7 years; and assessments using ILI, pressure testing or direct assessment within the maximum intervals specified in the rule.
  - FAQ-41 states that the intervals are measured in terms of actual years, not calendar years.
  - FAQ-42 states that some reassessments will be required before all baseline assessments are completed if operators use the entire 10 year period to perform baseline assessments.
  - FAQ-43 states that the maximum intervals in the rule may be extended if the operator implements exceptional performance-based programs, or if the operator submits a waiver request to PHMSA.
  - FAQ-45 states that operators meeting the criteria for exceptional performance can extend reassessment intervals.
  - FAQ-133 states that 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.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F4a - Protocol F.4.a.

F.04.b. For pipelines operating at or above 30% SMYS, verify that the operator meets the following requirements:

i. If the operator establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment (refer to Protocol G) must be performed at intervals not to exceed seven (7) years followed by a reassessment at the interval established by the operator (refer below). [§192.939(a)]

ii. Unless a deviation is permitted under §192.913(c), the maximum reassessment interval shall not exceed the values listed in the §192.939(b) table. [§192.937(a)]

iii. If the reassessment method is a pressure test, ILI, or other equivalent technology, the interval must be based on either: (1) the identified threat(s) for the covered segment (see §192.917) and on the analyses of the results from the last integrity assessment, and a review of data integration and risk assessment; or (2) using the intervals specified for different stress levels of pipeline listed in ASME B31.8S-2004, Section 5, Table 3. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939. [§192.939(a)(1)]

iv. If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator's interval determination.

F.04.b. Supplemental Guidance:

- The operator's IMP should require the performance of data integration and risk assessment that may determine that a shorter interval than the maximum is appropriate for the segment under consideration. If the evaluation concludes that a shorter interval is appropriate, the operator must proceed with the shorter interval.
- Verify that the operator's IMP requirements do not exceed the maximum interval requirements specified in ASME B31.8S-2004, Section 5, Table 3, of either 10 or 15 years depending on whether the pipe is operated at more than 50% SYMS or not, and depending on the predicted failure pressure or the pressure test values.
- If a hydrostatic pressure test was performed per Subpart J requirements, then the operator may use a seven year reassessment interval (refer to FAQ-207 and FAQ-236). Extended intervals may be achieved per ASME B31.8S-2004, Section 5, Table 3 and the guidance below.
- If the predicted failure pressure ratio or the test pressure ratio falls in between the values listed in ASME B31.8S-2004, Section 5, Table 3, interpolation is acceptable. The baseline Pf/MAOP or TP/MAOP is 1.1. For ratios higher than 1.1 use:

  - 0.03 per year if >= 50% SMYS;
  - 0.06 per year if >= 30% SMYS and
  - For example a segment >50% SMYS and the test pressure is 1.35 times the MAOP, the maximum interval would be 8.3 years (1.35-1.25 = 0.1 divided by 0.03 is 3.3 years plus the 5-year interval allowable for test pressure of 1.25 times MAOP).
  - In no event are operators required to assess more frequently than seven years unless their risk assessment indicates a need to do so.
- If the operator chooses external corrosion direct assessment as the assessment method, the reassessment interval is based on the NACE standard, but not to exceed the maximum values specified in ASME B31.8S-2004, Section 5, Table 3. (Refer to Protocol D)
- If the assessment method is internal corrosion direct assessment or stress corrosion cracking direct assessment, the operator must base the reassessment interval on 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 (refer to Protocol D, Supplemental Guidance Appendix F.01, Bookmark F4 - Protocol F.4, Supplemental Guidance Appendix F.02, Reassessment Interval Determination Methods and Supplemental Guidance Appendix F.03, Reassessment Intervals for Hydro-Tests Based on Pressure Cycle Defect growth Analysis) but not to exceed the maximum values specified in ASME B31.8S-2004, Section 5, Table 3.
- Refer to the following FAQs:
  - FAQ-40 states that assessments must be performed at intervals no longer than 7 years; and assessments using ILI, pressure testing or direct assessment within the maximum intervals specified in the rule.
  - FAQ-41 states that the intervals are measured in terms of actual years, not calendar years.
  - FAQ-45 states that operators meeting the criteria for exceptional performance can extend reassessment intervals.
  - FAQ-133 states that 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.
  - FAQ-178 states that operators planning to increase stress levels (e.g. from 30% SMYS) must determine whether additional actions need to take place such as performing an additional assessment since maximum intervals vary for different stress levels.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F4b - Protocol F.4.b.

F.04.c. For pipelines operating < 30% SMYS, verify that the operator selects one of the following reassessment approaches:

i. Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in §192.939(a)(1) except that the stress level referenced in §192.939(a)(1)(ii) would be adjusted to reflect the lower operating stress level. However, if an established interval is more than seven (7) years, the operator must conduct at seven (7) year intervals either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939.[§192.939(b)(1)]

ii. Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to Protocol D for evaluating the operator's interval determination. [§192.939(b)(2), §192.939(b)(3) and §192.939(b)(4)]

iii. Reassessment by confirmatory direct assessment at seven year intervals in accordance with subpart 192.931, with reassessment by one of the methods listed in §192.939(b)(1) – §192.939(b)(3) by year 20 of the interval. [§192.939(b)(4)]

iv. Reassessment by the "low stress method" at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in §192.939(b)(1) through §192.939(b)(3) by year 20 of the interval. [§192.939(b)(5)]

F.04.c. Supplemental Guidance:

- The process for determining the reassessment interval is essentially the same as that used for pipe operating over 30% SMYS. The main difference is that the entry point for ASME B31.8S-2004, Section 5, Table 3, is the last column
- If the predicted failure pressure ratio or the test pressure ratio falls in between the values listed in ASME B31.8S-2004, Section 5, Table 3, interpolation is acceptable. The baseline Pf/MAOP or TP/MAOP is 1.1. For ratios higher than 1.1 use:
    - 0.11 years
    - For example a segment < 30% SMYS and the test pressure is 2 times the MAOP, the maximum interval would be 7.7 year (2.0 - 1.7 = 0.3 divided by 0.11 is 2.7 years plus the 5-year interval allowable for test pressure of 1.7 times MAOP).
    - In no event are operators required to assess more frequently than seven years unless their risk assessment indicates a need to do so.
- Similarly, if the reassessment interval for pipe operating at less than 30% SMYS is greater than 7 years, a CDA or a low stress reassessment must be performed at 7 year (or shorter) intervals.
- CDA is a streamlined derivation of Direct Assessment (an acceptable assessment method) and is not acceptable, by itself, as the sole method to be used for primary reassessment of pipeline segments covered by Subpart O.
- A low stress reassessment is performed at 7-year intervals much like a CDA. If this method if selected, the operator must still perform an assessment using ILI, pressure test or direct assessment by year 20 of the interval.
- Refer to the following FAQs:
    - FAQ-40 states that assessments must be performed at intervals no longer than 7 years; and assessments using ILI, pressure testing or direct assessment within the maximum intervals specified in the rule.
    - FAQ-41 states that the intervals are measured in terms of actual years, not calendar years.
    - FAQ-45 states that operators meeting the criteria for exceptional performance can extend reassessment intervals.
    - FAQ-133 states that 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.
    - FAQ-178 states that operators planning to increase stress levels (e.g. from 30% SMYS) must determine whether additional actions need to take place such as performing an additional assessment since maximum intervals vary for different stress levels.
    - FAQ-228 states that performance of a CDA does not extend the interval of a primary reassessment.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F4c - Protocol F.4.c.

F.04.d. Verify that a covered segment on which a prior assessment was credited as a baseline assessment under subpart §192.921(e) is required to be reassessed by no later than December 17, 2009. [§192.937(a)]

F.04.d. Supplemental Guidance:

- Identify those segments that were credited with a prior assessment for the baseline assessment and verify that the reassessment schedule for these segments does not exceed December 17, 2009.
    - FAQ-152 states that prior assessments must address all applicable threats to the pipeline.
- The reassessment interval for segments with baselines assessments credited prior to December 17, 2002, depends on the results of the operator's risk analysis, when the prior test was conducted, what method was used on the prior assessment, and operating conditions of the segment in question.
    - FAQ-27 states that if the period between the baseline assessment date and December 17, 2009 is more than the maximum reassessment interval allowed by §192.939 (or more than a shorter interval which the operator concludes, based on its risk assessment, should be used), then the reassessment must be conducted with one of the methods listed in §192.937(c)(1)-(4) (i.e., ILI, pressure test, DA, or other technology). If the maximum allowed interval has not been reached, then the initial reassessment may be conducted

using confirmatory direct assessment [§192.937(c)(5)], with reassessment using one of the methods in §192.937(c)(1)-(4) before the maximum reassessment interval expires.

- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F4d - Protocol F.4.d.

F.04.e. Verify that reassessment intervals are appropriate and that adequate documentation and technical bases support the intervals selected.

F.04.e. Supplemental Guidance:

- For segments that have completed baseline assessments, verify that the next assessment method and schedule have been documented.
- Evaluate the intervals selected for the next assessment to ensure that a bona fide evaluation of re-assessment interval was conducted.
- Verify that adequate justification exists to support the established reassessment interval.
- Several generic "IMP-in-a-Box" plans include a corrosion rate formula ($Cr = d_{max} / 0.75 X N_{years}$) for determination of reassessment intervals. Operators have not documented a technical basis justifying the adequacy of this formula and it is not endorsed in any known consensus industry standard. Inspection should verify that a documented basis for the use of this formula (or other formula) is provided in IMP documentation.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F4e - Protocol F.4.e.

F.05 Deviation from Reassessment Requirements

If the operator elects to deviate from certain requirements listed in §192.913(c), verify that the operator uses a performance based approach that satisfies the requirements for exceptional performance as follows: [§192.913 and ASME B31.8S-2004]

F.05 *Supplemental Guidance:*

- Protocol F.05 applies only if an operator pursues a performance-based program, but does not apply to operators implementing the prescriptive approach.
- Perform a detailed review of any programs identified as "exceptional performance" to verify that all of the requirements specified in the rule (see below) for such programs were appropriately implemented. Refer to Supplemental Guidance Appendix F.05, White Paper, Exceptional Performance, for further guidance.
- Additional discussion of provision of "exception performance" to non-covered segments is provided in Supplemental Guidance Appendix C.03, White Paper, "Look Beyond" Provisions.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F5 - Protocol F.5.
- FAQ-185 discusses that operators with mature integrity management programs who have conducted at least 2 assessments on covered segments can qualify for performance-based approach and extended reassessment intervals.

F.05.a. Verify that the operator has a performance based integrity management program that meets or exceeds the performance-based requirements of ASME B31.8S-2004 and includes, at a minimum, the following elements: [§192.913(a)]

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 (Refer to Protocol I);
vii. Semi-annual performance measures beyond those required in §192.943 that are part of the operator's performance plan. [See §192.911(i)] Refer to Protocol I.
viii. An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

F.05.a. Supplemental Guidance:

- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F5a - Protocol F.5.a.
- Refer to Supplemental Guidance Appendix C.01, White Paper, Data Gathering and Integration, for further guidance on performance based integrity management programs.
- (i)
  - The risk analysis process must be "comprehensive." For performance based programs, each threat analysis must evaluate all 21 specific threats listed in ASME B31.8S-2004, Section 2.2. The distinction between "comprehensive" risk analysis process and a "normal" risk analysis process is also discussed in the risk analysis Protocol C.
  - A performance based IM program that uses more comprehensive analysis methods should consider the following in order to exclude a threat in a segment (ASME B31.8S-2004, Section 5.10):
    - There is no history of a threat impacting the particular segment or pipeline system;
    - The threat is not supported by applicable industry data or experience;
    - The threat is not implied by related data elements in that the application of related data elements may provide an indication of a threat's presence when other data elements are not available;
    - The threat is not supported by like/similar analyses;
    - The threat is not applicable to system or segment operating conditions.
    - Even if an operator concludes that a particular threat is not applicable to its pipeline, the threat evaluation must be documented and the basis for drawing such conclusions must be documented.
- (ii)
  - The data elements listed in §192.917(b) must be considered for both covered and non-covered segments.
  - All risk data is to be used; i.e. selected risk data cannot be omitted from use in the program.
  - Refer to Protocol C.
- (iii)
  - This aspect of the performance based program should be evaluated during Protocol C, the review of the risk analysis process.
  - FAQ-227 states that the risk assessment and data integration for performance-based programs should be more thorough, complete, and mature than those used in prescriptive programs.
- (iv)
  - IM lessons learned are to be applied to ALL parts of the system.
  - Select a sample of completed assessments of covered segments and verify that the operator has identified lessons learned. Then determine if those lessons were applied to non-covered segments or whether there is evidence that the lessons will be applied.

- (v)
  - Cause analysis must be applied to "every" incident. Note the use of the term "incident" and not "release". This would include near misses and operational errors.
  - Select a sample of known incidents and verify that each one was evaluated and that any implications to other segments were identified and actions taken.
- (vi)
  - Operator must demonstrate that applicable threats are "controlled." This is a more exacting requirement than the general performance measures in §192.945.
  - Refer to Protocol I.
- (vii)
  - §192.911(i) refers to ASME B31.8S-2004, Section 9. These measures are more extensive than the 4 performance measures all operators must submit under the prescriptive program. The submittal of these measures (basically all performance measures from ASME B31.8S-2004 included in the operator's program) is a significant upgrade.
- (viii)
  - The analysis to support reassessment intervals and remediation schedules must be included. It is understood that these analyses must be technically sound, comprehensive, and valid.
  - Refer to the following FAQs regarding extending reassessment intervals:
    - FAQ-43 states that operators can either submit waivers to PHMSA or implement exceptional performance through a performance-based program in order to extend reassessment intervals.
    - FAQ-45 states that operators may use performance-based programs and demonstrate exceptional performance in order to extend reassessment intervals.

F.05.b. Verify that the operator has completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach and is able to demonstrate that each assessment effectively addressed the identified threats on the covered segments. [§192.913(b)(2)(i)]

F.05.b. Supplemental Guidance:

- Credited assessments can go back to prior to 12/2002. Two assessments means two complete assessments, each of which may have involved more than one assessment method (e.g., deformation and metal loss runs).
- Confirmatory direct assessments or low stress reassessments cannot be counted toward meeting this requirement.
- FAQ-173 states that a CDA cannot be credited as a second assessment if an operator desires to move to a performance-based program.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F5b - Protocol F.5.b.
- Refer to Supplemental Guidance Appendix F.05, White Paper, Exceptional Performance, for further guidance.

F.05.c. Verify the operator has remediated anomalies identified in the more recent assessment per the requirements of §192.933. [§192.913(b)(2)(ii)]

F.05.c. Supplemental Guidance:

- Refer to Protocol E for information regarding remediation requirements.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F5c - Protocol F.5.c.

F.05.d. Verify the operator has incorporated the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. [§192.913(b)(2)(ii)]

F.05.d. Supplemental Guidance:

- By reviewing documentation, verify that the more recent assessment has been evaluated, the results and lessons learned identified, and applicable findings factored into the risk assessment and data integration process.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F5d - Protocol F.5.d.

F.05.e. Verify that deviations are allowed only for the timeframe for reassessment as provided in §192.939 except that reassessment by some method allowed by Subpart O (e.g., confirmatory direct assessment) must be completed at intervals not to exceed seven (7) years. [§192.913(c)(1)]

F.05.e. Supplemental Guidance:

- While the rule allows extended reassessment intervals for operators that implement exceptional performance programs, an "interim" reassessment, i.e. a CDA, must still be performed within the 7-year requirement. Verify that such an interim measure is scheduled or has been performed.
- Refer to the following FAQs:
    - FAQ-43 states that operators can either submit waivers to PHMSA or implement exceptional performance through a performance-based program in order to extend reassessment intervals.
    - FAQ-45 states that operators may use performance-based programs and demonstrate exceptional performance in order to extend reassessment intervals.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F5e - Protocol F.5.e.

F.06 Waiver from Reassessment Interval

Verify that the operator's program requires that it apply for a waiver, should it become necessary, from the required reassessment interval. The waiver request must demonstrate that the waiver is justified as specified in the rule. Such a waiver request may only be made in the following limited situations: [§192.943]

F.06 *Supplemental Guidance:*

- 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.
- Must show that the waiver is consistent with pipeline safety.
- Refer to the following FAQs:
    - FAQ-43 states that an operator may submit a waiver request to PHMSA when inspection tools are not available or where conducting an assessment would imperil gas supply.
    - FAQ-205 states that an operator should use the best information that they have available in performing the data integration and analysis.
    - FAQ-210 states that notifications should be sent both to PHMSA and to states.
- Additional guidance for this protocol and its subelement questions can be found in Supplemental Guidance Appendix F.01, Bookmark F6 - Protocol F.6.

F.06.a. Lack of internal inspection tools. [§192.943(a)(1)]

F.06.a. Supplemental Guidance:

- 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.
    - FAQ-43 states that an operator may submit a waiver request to PHMSA when inspection tools are not available or where conducting an assessment would imperil gas supply.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F6a - Protocol F.6.a.

F.06.b. Cannot maintain local product supply. [§192.943(a)(2)]

F.06.b. Supplemental Guidance:

- 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.) Inspectors should be aware that other operators may be able to provide a gas supply. Also, operators may be able to bring in portable LNG plants which can often supply small towns (e.g., population 15,000). Valving and emergency interconnects can also be used, but again operators may be reluctant to use because of expense. Operators should be able to show calculations of demand in cubic feet vs. supply in cubic feet to demonstrate that they can not hold loads with temporary LNG or alternative supplies.
- FAQ-43 states that an operator may submit a waiver request to PHMSA when inspection tools are not available or where conducting an assessment would imperil gas supply.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F6b - Protocol F.6.b.

F.06.c. Application must be made at least 180 days before the end of the required reassessment interval. (Exception: If local product supply issues make the 180 day submittal impractical, an operator must apply for the waiver as soon as the need for waiver becomes known). [§192.943(b)]

F.06.c. Supplemental Guidance:

- Inspectors should review any documentation associated with waiver requests.
- Refer to the following FAQs:
    - FAQ-43 states that an operator may submit a waiver request to PHMSA when inspection tools are not available or where conducting an assessment would imperil gas supply.
    - FAQ-210 states that notifications must be sent to both PHMSA and state authorities when the pipeline is under state jurisdiction.
- Additional guidance for this protocol subelement can be found in Supplemental Guidance Appendix F.01, Bookmark F6c - Protocol F.6.c.

Protocol Area G. Confirmatory DA

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G.01 Confirmatory Direct Assessment, CDA

If using confirmatory direct assessment (CDA) as allowed in §192.937, verify that the operator's integrity management plan meets the requirements of §192.931, §192.925 (ECDA) and §192.927 (ICDA). [§192.931]

G.01 *Supplemental Guidance:*

- 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.
    - CDA is not applicable for any threats other than external or internal corrosion.
    - CDA can not be used to lengthen full assessment intervals.
        - FAQ-228 clarifies that CDA is only an interim assessment technique and as such re-assessment intervals can only be shortened or left the same. There are no provisions for lengthening the re-assessment interval.
    - CDA can be used to shorten or maintain full assessment intervals.
    - CDA can be used for assessments conducted on no longer than 7 year intervals when full re-assessments are scheduled to occur at intervals longer than 7 years.
    - FAQ-40 clarifies that both the PSIA and the rule mandate that periodic integrity assessments MUST be performed at least every 7 years. In between full assessments, which are specified in §192.939, CDA may be used for all covered segments regardless of the operating stress and special preventive and mitigative measures can be used on low stress covered segments to fulfill the 7 year period.
    - FAQ-46 clarifies that there are 4 acceptable integrity assessment methods, in line inspection, pressure testing, direct assessment (for EC, IC, and SCC threats) and "other technology". CDA can be used at the 7 year intervals as an interim assessment method if the full assessment requirements are longer than that period.
    - FAQ-216 clarifies that operators must do interim assessments of all covered segments every 7 years per the requirements of the PSIA. Covered segments operating at less than 30% SMYS can be assessed using the regular assessment methods, CDA or via preventive and mitigative measures as outlined in §192.941.
    - CDA cannot be credited as a second assessment if an operator intends to move to a performance-based program.
        - FAQ-173 clarifies that only full assessments can be used for credit towards the exceptional performance goals.
    - Operators must prepare a CDA plan prior to using CDA as an interim assessment method. See §192.931 for specifics.
- Operators that use CDA must have a plan that meets the requirements in §192.925 (ECDA) and §192.927 (ICDA). §192.931 provides specific requirements for what must be contained by the plan.
- FAQ-133 states that 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.

G.01.a. Verify that the operator's CDA plan for external corrosion complies with all of the requirements contained in §192.925 (See Protocol D.01 ~ Protocol D.05) with the following exceptions, [§192.931(b) and §192.925]

i. The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application
ii. The procedures for direct examination and remediation must provide that all immediate action indications and at least one scheduled action indication are excavated for each ECDA region.

G.01.a. Supplemental Guidance:

- For operators who use CDA for external corrosion, they must comply with §192.925 with several exceptions. They must also comply with NACE RP0502-2002, ASME B31.8S-2004, Section 6.4.1, ASME B31.8S-2004, Appendix A1 and ASME B31.8S-2004, Appendix B1.
- Protocol D.01 through Protocol D.05 apply and should be followed except for the following two exceptions:
  i. One of the exceptions to the requirements of §192.925 (and NACE RP0502-2002) is that only one indirect inspection tool need be utilized.
  ii. The other exception to §192.925 (and NACE RP0502-2002) is that only one scheduled indication need be excavated.
- In all cases, the maximum allowable assessment interval can not be greater than that stated in ASME B31.8S-2004, Table 3.
  - Refer to Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval, for additional guidance on calculation of remaining life and re-assessment intervals.
- The assessment interval can not be lengthened for the external corrosion threat.
- The assessment interval can be shortened for the external corrosion threat depending on the findings of CDA.
- All immediate indications on the covered segment must be excavated (in addition to the one scheduled indication).
- Any indication that will affect the integrity of the covered segment must be excavated (in addition to the one scheduled indication).

G.01.b. Verify that the operator's CDA plan for internal corrosion complies with all of the requirements contained in §192.927 (See Protocols D.6 ~ D.9) except that procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.[§192.931(c) and §192.925]

G.01.b. Supplemental Guidance:

- For operators who use CDA for internal corrosion, they must comply with the 4 step ICDA process outlined in §192.927 with one exception. They must also comply with ASME B31.8S-2004, Section 6.4.2, ASME B31.8S-2004, Appendix A2 and ASME B31.8S-2004, Appendix B2.
- The exception to §192.927 is that only one high risk indication need be excavated.
- Protocol D.06 through Protocol D.09 apply and should be followed with the one exception specified above for §192.927.
- In all cases, the maximum allowable assessment interval can not be greater than that stated in ASME B31.8S-2004, Table 3
- The assessment interval can not be lengthened for the internal corrosion threat.
- The assessment interval can be shortened for the internal corrosion threat depending on the findings of CDA.
- If a defect is discovered that needs remediation prior to the next scheduled full assessment, it must be evaluated using the remaining life calculations and reassessment intervals found in NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3.

- Refer to Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval, for additional guidance on calculation of remaining life and re-assessment intervals.

G.01.c. When using CDA carried out under §192.931(b) or (c), if an operator discovers any defect requiring remediation prior to the next scheduled assessment, verify that the operator evaluates the need to accelerate the schedule for the next assessment. If the schedule is accelerated, verify that the new assessment scheduled is determined using the methodology documented in NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3. [§192.931(d)]

i. If the defect requires immediate remediation, verify the operator reduces pressure consistent with §192.933 (See Protocol E) until the operator has completed reassessment using one of the assessment techniques allowed in §192.937 (See Protocol F). [§192.931(d)]

G.01.c. Supplemental Guidance:

- NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3 must be used to calculate the remaining life of the defect and the reassessment interval when operators perform remediation of defects discovered by CDA for both internal and external corrosion threats.
  - Operators must take a pressure reduction as specified in §192.933(d)(1) for all defects that require immediate action.
  - Pressure reductions can only be in effect for 1 year, therefore, operators must remediate the defect within that time limit unless other steps are taken as outlined in §192.933(a) and ASME B31.8S-2004, Section 7.
  - NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3 must be used to schedule the next reassessment if CDA identifies any defects requiring remediation prior to the next scheduled assessment.
- FAQ-132 addresses determination of new reassessment schedules for defects requiring remediation; Re-assessment under the CDA process uses the remaining life calculation and half life calculations in NACE RP0502-2002, Section 6.2 and NACE RP0502-2002, Section 6.3. These calculations give operators the allowable re-assessment interval of internal corrosion defects providing they are less than the maximum in ASME B31.8S-2004, Table 3, or §192.939.
- Refer to Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval, for additional guidance on calculation of remaining life and re-assessment intervals.

Protocol Area H. Preventive and Mitigative Measures

- H.01 General Requirements (Identification of Additional Measures)
- H.02 Third Party Damage
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H.01 General Requirements (Identification of Additional Measures)

Verify that a process is in place to identify additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. [§192.935(a)]

H.01 *Supplemental Guidance:*

- Operators are expected to promptly identify the need for additional preventive and mitigative measures. See FAQ-90, which states:
    - Operators should not wait until after the baseline assessment to determine P&M measures, especially for segments not scheduled for assessment in the near term.
    - Operators should determine P&M measures within one year after completing an integrity assessment.
    - Operators should document a schedule for implementing P&M measures.
- FAQ-180 addresses how PHMSA will evaluate required "enhancements" for operators that are already operating at high level with respect to damage prevention measures. The rule does not require that operators implement additional actions beyond those they presently implement, only that they implement actions beyond those already required in other sections of Part 192. Operators who are already implementing protective measures that go beyond the other regulations may not need to do more unless their risk analysis indicates otherwise. Inspections should include an evaluation of the operator's risk analysis and consider whether additional protective measures that have been implemented are consistent with its conclusions.
- Each operator is likely to 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.

H.01.a. Verify that the process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by §192.917. [Note: Protocol H.08 addresses the implementation decision process for additional preventive and mitigative measures.] [§192.935(a)]

H.01.a. Supplemental Guidance:

- 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. The operator's IMP should include procedures or processes for identification of additional measures based on identified threats to each pipeline segment and the risk analysis required by §192.917.
- Threats that the operator's process must consider include, but are not limited to, those identified in ASME B31.8S-2004, Section 2.2 such as 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; and human error. The operator's IMP should, as a minimum, include consideration of these threats in the evaluation process for identification of preventative and mitigative measures.
- IM Rule §192.917(c) requires the use of risk assessment for determining what preventative and mitigative measures are needed for covered segments. The requirements for what constitutes the required risk assessment process is defined in ASME B31.8S-2004, Section 5. The operator's IMP should describe its risk assessment process and demonstrate consistency with the expectations established by ASME B31.8S-2004, Section 5.
- "**SHOULD**" REQUIREMENT: ASME B31.8S-2004, Section 5.11 also invokes ASME B31.8S-2004, Section 7. It states in Section 7.6 that Prevention strategies **should** consider the classification of identified threats as time-dependent, stable or time-independent in order to ensure that effective prevention methods are utilized. [Re: Protocol L.03]
- For examples of how risk analyses are used in determining appropriate preventive and mitigative measures, see Supplemental Guidance Appendix H.01, Risk Analysis Application Examples:
    - Qualitative Index Model - Supplemental Guidance Appendix H.01, Bookmark Qualitative
    - SME-Based Risk Analysis Approach - Supplemental Guidance Appendix H.01, Bookmark SME

- Quantitative Risk Model - Supplemental Guidance Appendix H.01, Bookmark Quantitative

H.01.b. Verify that additional measures evaluated by the operator cover a spectrum of alternatives such as, but 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. [§192.935(a)]

H.01.b. Supplemental Guidance:

- The operator's IMP must have a documented decision process that includes a risk analysis of its pipeline to identify additional measures to protect high consequence areas and to enhance public safety. The process must consider a broad range of potential preventive and mitigative measures including, but not necessarily be limited to, the following potential measures explicitly stated in the rule:
  - 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
- Other preventive or mitigative measures not specifically referenced by the Rule that an operator could consider include:
  - implementing damage prevention best practices,
  - establishing better monitoring of cathodic protection where corrosion is a concern,
  - establishing shorter inspection intervals,
  - increasing the frequency of ROW inspections,
  - adopting other management controls
- ASME B31.8S-2004, Section 5.11 further reinforces that consideration of a variety of options is a necessity.
- Preventive and mitigative measures that are proposed to reduce specific identified risks are best developed or specified by the parts of the organization that have the most knowledge of the areas under evaluation. For example, preventive and mitigative measures for pipelines that are susceptible to corrosion should be strongly influenced by the corrosion control technical staff, while decisions regarding EFRDs and Leak Detection would be strongly influenced by the controls technical staff and operations personnel. Certain core groups such as Operations, Maintenance, Corrosion Control, Engineering, Planning, and Project Management should be involved in the basic decision making process for evaluating additional preventive and mitigative measures.

H.02 Third Party Damage

Verify that the following preventive and mitigative requirements regarding threats due to third party damage have been addressed: [§192.935(b)(1) and §192.935(e)]

H.02 *Supplemental Guidance:*

- Note: This Protocol applies to pipelines operating above 30% SMYS. Specific requirements pertaining to pipelines operating below 30% SMYS or to plastic transmission pipeline are provided in Protocol H.03 and Protocol H.04.
- It is clear that virtually all pipeline segments, especially those in HCAs, are susceptible to the threat of future TPD. The only way to address the threat of a future TPD event is to take effective

preventive actions. Refer to Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage.

- FAQ-91 states that 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 could affect an HCA, and take comprehensive additional preventive measures.

H.02.a. Verify implementation of enhancements to the §192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that the enhanced measures include, at a minimum: [Note: As noted in Protocol H.03 and Protocol H.04, a subset of these enhancements are required for pipelines operating below 30% SMYS and for plastic transmission pipelines.] [§192.935(b)(1)]

i. Using qualified personnel (see Protocol L.02 - §192.915(c)) 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. [§192.935(b)(1)(i)]
ii. Collecting, in a central database, location-specific information 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. [§192.935(b)(1)(ii)]
iii. Participating in one-call systems in locations where covered segments are present. [§192.935(b)(1)(iii)]
iv. Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. [§192.935(b)(1)(iv)]
    1. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE RP0502-2002 must be conducted. [§192.935(b)(1)(iv)]
        A. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ASME B31.8S-2004, Section 7.5 and §192.933. [§192.935(b)(1)(iv)]

H.02.a. Supplemental Guidance:

- Operators are required to have a written damage prevention program that meets the requirements of §192.614. Section 192.935(b)(1) requires that this program be enhanced to include additional requirements. Inspection should verify that either the damage prevention program includes the required enhancements or that the operator's IMP has elements addressing the required enhancements and complements the written damage prevention program required by §192.614. The enhancements, at a minimum, must include the following:
    - Using qualified operator personnel for work that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. Personnel should be qualified consistent with the requirements of §192.915 and verification that personnel are qualified should be addressed through the inspection performed for Protocol L.02.
    - A central database of information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system. The data must include a root cause analysis supporting 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. The database or printouts of information from the database should be reviewed to confirm it satisfies requirements. Inspectors should also review records of preventative or mitigative measures that have been taken as result of root cause analysis of excavation damage.

- Participation in a one-call system in locations where covered segments are present. One-call tickets may be reviewed to verify participation.
- Qualified operator personnel must monitor all excavations conducted on covered segments.
  - If an operator finds physical evidence of encroachment involving excavation near a covered segment that the operator did not monitor, then the operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP0502–2002.
  - Operators must document that excavations were monitored. Inspectors may select sample one-call tickets for detailed review of excavation records to verify that the operator documented the excavation and that it was monitored by a qualified person. Records should also document how the operator became aware of the excavation, such as:
    - One call
    - Direct contact by excavator
    - ROW patrol
- Excavation and remediation of any indication of coating holidays or discontinuity warranting direct examination. The program must specify that excavation and remediation should be performed in accordance with ASME B31.8S-2004 and §192.933. The program must also specify that repairs are made with materials and processes that are suitable for the pipeline operating conditions and meet ASME B31.8S-2004 requirements. Records of excavations and repairs should be reviewed to ensure compliance with these requirements.

H.02.b. If the threat of third party damage is identified by results of the §192.917(b) (Protocol C.02) and ASME B31.8S-2004, Appendix A7 data integration processes, verify that comprehensive additional preventive measures are implemented. [§192.917(e)(1)]

H.02.b. Supplemental Guidance:

- The IMP Rule requires that operators implement data integration and collection processes. These processes are inspected under Protocol C.02 and Protocol C.03. As part of these processes, risk assessments are to be performed to determine what preventative and mitigative measures are needed for covered segments.
- Implementation of the data integration process should be reviewed to determine if third party damage was identified as a threat to covered pipeline segments.
- For third party damage risks identified, the operator should have implemented comprehensive additional preventive measures.
- Inspectors should review the operator's decision making process that is used to determine what preventive measures should be taken. Measures may include, but are not limited to: increased patrol frequency, improved public communication and awareness, and additional pipeline location markers.

H.03 Pipelines Operating Below 30% SMYS

Verify that the following preventive and mitigative requirements for pipelines operating below 30% SMYS have been addressed: [§192.935(d)]

H.03.a. For pipelines operating below 30% SMYS located in a high consequence area:

i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) 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. [§192.935(d) and

§192.935(d)(1)] [Note: This requirement is also contained in Protocol H.02.a.i for pipelines operating above 30% SMYS.]

ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d) and §192.935(d)(1)] [Note: This requirement is also contained in Protocol H.02.a.iii for pipelines operating above 30% SMYS.]

iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d) and §192.935(d)(2)]

1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2)]

H.03.a. Supplemental Guidance:

- For pipelines operating below 30% SMYS located in a high consequence area, inspection should verify the operator's compliance with third party damage requirements:
  - Using qualified personnel 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. Personnel should be qualified consistent with the requirements of §192.915 and verification that personnel are qualified should be addressed through the inspection performed for Protocol L.02.
  - Participation in a one-call system in locations where covered segments are present. One-call tickets may be reviewed to verify participation.
  - Qualified operator personnel must monitor all excavations conducted on covered segments.
    - If an operator finds physical evidence of encroachment involving excavation near a covered segment that the operator did not monitor, then the operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP0502–2002.
    - Operators must document that excavations were monitored. Inspectors may select sample one-call tickets for detailed review of excavation records to verify that the operator documented the excavation and that it was monitored by a qualified person. Records should also document how the operator became aware of the excavation, such as:
      - One call
      - Direct contact by excavator
      - ROW patrol
- For pipelines operating below 30% SMYS located in a high consequence area, inspection should verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. If indications of unreported construction activity are found, inspection should verify that required follow up investigations are conducted to determine if mechanical damage has occurred. A review of the operator's IMP should be conducted to verify the inclusion of these elements.

H.03.b. For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area:

i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) 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. [§192.935(d), §192.935(d)(1) and §192 Table E.II.1] [Note: This requirement is also contained in Protocol H.02.a.i for pipelines operating above 30% SMYS.]

ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d),

§192.935(d)(1) and §192 Table E.II.1] [Note: This requirement is also contained in Protocol H.02.a.iii for pipelines operating above 30% SMYS.]

iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2) and §192 Table E.II.1]

1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2) and §192 Table E.II.1]

iv. Verify that the operator performs semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [§192.935(d)(3)and §192 Table E.II.1]

H.03.b. Supplemental Guidance:

- For pipelines operating below 30% SMYS located in a Class 3 or 4 area but not in a high consequence area, inspection should verify the operator's compliance with third party damage requirements:
  - Using qualified personnel 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. Personnel should be qualified consistent with the requirements of §192.915 and verification that personnel are qualified should be addressed through the inspection performed for Protocol L.02.
  - The operator's programs should be reviewed to verify participation in one-call systems in locations where covered segments are present. A review of one-call system logs may be reviewed to verify participation.
- For pipelines operating below 30% SMYS located in a Class 3 or 4 area but not in a high consequence area, inspection should verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. Inspection should verify that the operator's IMP includes elements requiring investigation of unreported construction activity.
- For pipelines operating below 30% SMYS located in a Class 3 or 4 area but not in a high consequence area, inspection should verify that the operator performs leak surveys as required. Leak surveys are required for all pipe by §192.706, and for pipelines located in Class 3 or 4 areas but not in HCA by §192.935(d). The required periodicity for leak surveys differs based on the class location and whether or not the line transports odorized gas. The following tables summarize the more restrictive requirements:

Class 3	Cathodically Protected, electrical surveys practical	Cathodically Protected, electrical surveys impractical	Cathodically unprotected
Odorized	Semi-annual (935(d))	Quarterly (935(d))	Quarterly (935(d)
Unodorized	Semi-annual (935(d) and 706(a))	Quarterly (935(d))	Quarterly (935(d))

Class 4	Cathodically Protected, electrical surveys practical	Cathodically Protected, electrical surveys impractical	Cathodically unprotected
Odorized	Semi-annual (935(d))	Quarterly (935(d))	Quarterly (935(d)
Unodorized	Quarterly (706(b))	Quarterly (935(d))	Quarterly (935(d))

The operator's IMP should be reviewed to ensure it requires semi-annual or quarterly leak surveys, as appropriate. Records documenting the conduct of the surveys should be reviewed.

- Operators must perform semi-annual leak surveys over the entire line as required by 192.935(d)(3). Quarterly leak surveys are required for areas where electrical surveys are impractical (e.g., casings, culverts, underwater areas). Quarterly leak surveys are also required for unprotected pipe. The surveys should be in areas where there is bare pipe without active corrosion as demonstrated by electrical surveys conducted every 3 years as required by 192.465(e). If an operator claims that the electrical survey is impractical under 192.465(e) justification must be documented.
- FAQ-230 states that this semi-annual requirement is to be consistent with the semi-annual intervals for leak surveys required by 192.706. Semi-annual leakage surveys to comply with 192.935(d)(3) should therefore be conducted at intervals not exceeding 7 1/2 months, but at least twice each calendar year. Quarterly surveys should be conducted at intervals not exceeding 4 1/2 months, but at least 4 times each calendar year.

H.04 Plastic Transmission Pipeline

For plastic transmission pipelines, verify that applicable third party damage requirements have been applied to covered segments of the pipeline. [§192.935(e)]

H.04.a. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) 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. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.02.a.i for non-plastic pipelines operating above 30% SMYS.]

H.04.a. Supplemental Guidance:

- For plastic transmission lines, verify the operator's process for compliance with third part damage requirements:
  - Using qualified personnel 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. Personnel should be qualified consistent with the requirements of 192.915 and verification that personnel are qualified should be addressed through the inspection performed for Protocol L.02.
  - The operator's programs should be reviewed to verify participation in one-call systems in locations where covered segments are present. One-call tickets could be reviewed to verify participation.
  - The operator's enhanced damage prevention program should provide for monitoring of excavations conducted on covered pipeline segments by pipeline personnel. The program should 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 either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP0502–2002. Inspection should verify that the operator's IMP includes elements requiring either excavation of the area near the encroachment or conduct of an above ground survey.
  - The operator's enhanced damage prevention program should also require excavation and remediation of any indication of coating holidays or discontinuity warranting direct examination. The program should specify that excavation and remediation should be performed in accordance with ASME B31.8S-2004 and §192.933. The program should also specify that repairs are made with materials and processes that are suitable for the pipeline operating conditions and meet ASME B31.8S-2004 requirements. Records of

excavations and repairs should be reviewed to ensure compliance with these requirements.

H.04.b. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iii for non-plastic pipelines operating above 30% SMYS.]

H.04.b. Supplemental Guidance:

- The operator's programs should be reviewed to verify participation in one-call systems in locations where covered segments are present.
- A review of one-call tickets may be used to verify participation and to identify excavations to verify that they should have been monitored per the following protocol.

H.04.c. Verify that the excavations on covered segments are monitored by pipeline personnel. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.]

i. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE RP0502–2002 must be conducted. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.]
    1. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ASME B31.8S-2004, Section 7.5 and §192.933. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.]

H.04.c. Supplemental Guidance:

- The operator's enhanced damage prevention program must provide for monitoring of excavations conducted on covered pipeline segments by pipeline personnel.
- Selected one-call tickets or log books can be used to identify excavations for detailed review.
- Inspectors should review the operator's documentation that demonstrates that excavations are monitored.
    - Documentation should identify how the operator became aware of the excavation, such as:
        - One-call ticket
        - Direct contact by excavator
        - ROW patrol
- 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 either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP0502–2002.
- The operator's enhanced damage prevention program must also require excavation and remediation of any indication of coating holidays or discontinuity warranting direct examination. The program must also specify that excavation and remediation be performed in accordance with ASME B31.8S-2004, Section 7.5 and §192.933. The program should also specify that repairs be made with materials and processes that are suitable for the pipeline operating conditions and meet ASME B31.8S-2004 requirements. Records of excavations and repairs should be reviewed to ensure compliance with these requirements.

H.05 Outside Force Damage

Verify that the operator adequately addresses threats due to outside force (e.g., earth movement, floods, unstable suspension bridge). [§192.935(b)(2)]

H.05 *Supplemental Guidance:*

FAQ-113 addresses the interpretation of the term "threat" in the context of P&M measures. The rule requires that additional measures must be taken. FAQ-113 clarifies that the actions taken, and the timeliness with which they are implemented, must be commensurate with the nature and severity of the threat that has been identified. The pipe replacement example cited in the rule would only be appropriate if the nature of the threat justified such drastic P&M measures.

H.05.a. If the operator makes a determination that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment (e.g., via Protocol C.01 activities), verify that measures have been taken to minimize the consequences to the covered segment. 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. [§192.935(b)(2)]

H.05.a. Supplemental Guidance:

- Operators are required to make a determination if outside forces (e.g., earth movement, floods, and unstable suspension bridge) are a threat to the integrity of a covered segment. If a threat applies, then measures must be taken to minimize the consequences to the covered segment. 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.
- Information on geographic areas with the potential for certain external threats can be found on the National Pipeline Mapping System (NPMS - http://www.npms.phmsa.dot.gov/). NPMS can be queried to determine areas with a high or medium risk of floods, landslides, earthquakes, or hurricanes.
- Inspection should verify that an operator's covered segments have been evaluated to identify susceptibility to outside force damage. Pipelines in mountainous terrain (which is subject to landslides or mudslides), and pipelines near rivers or river crossings (subject to flooding) should be reviewed to verify that operators properly evaluated the threat of outside force damage.
- Inspection should also verify that for pipelines that are susceptible to outside force damage, appropriate measures have been taken to minimize potential consequences to the covered segments.
- Sometimes earth movement can significantly displace the pipe, without causing rupture. In such cases, the stresses in the pipe can be dramatically increased, thus interacting with other threats such as:
    - SCC
    - manufacturing defect (such as LFERW seam defects)
    - cracks
    - dents

H.06 Corrosion

Verify that the operator takes required actions to address corrosion threats. [§192.917(e)(5)]

H.06.a. Verify that the operator makes a determination of whether or not corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933). [§192.917(e)(5)]

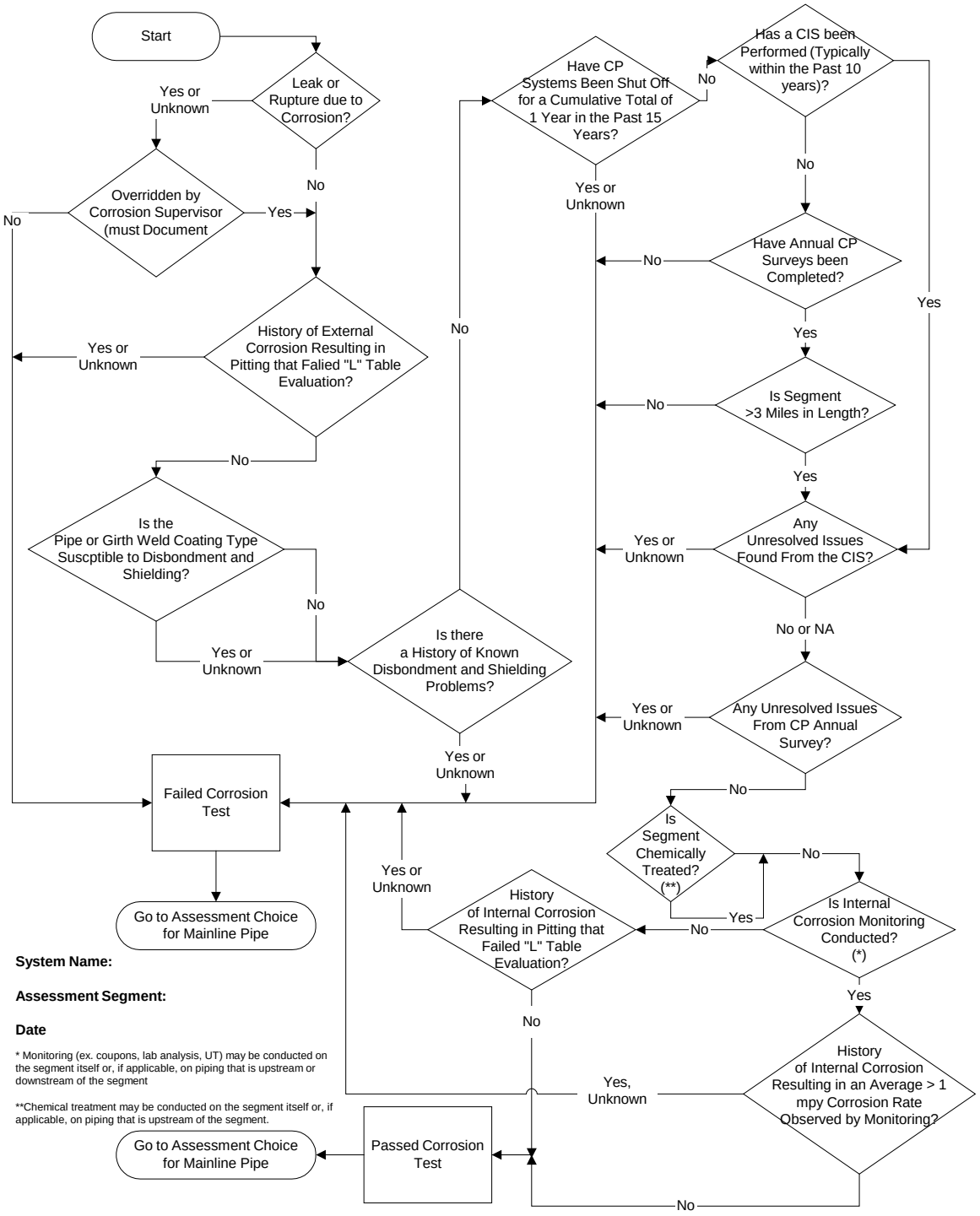
i. If such corrosion is identified, then verify that:

1. The corrosion is evaluated and remediated, as necessary, for all pipeline segments (both covered and noncovered) with similar material coating and environmental characteristics. [§192.917(e)(5)]
2. A schedule is established for evaluating and remediating, as necessary, the similar segments consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair. [§192.917(e)(5)]

H.06.a. Supplemental Guidance:

- The operator's IMP should include provisions for remediation of corrosion threats. Inspection should verify that the operator makes a determination if corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933).
    - FAQ-135 states that that operators who identify corrosion in a covered segment that could adversely affect the integrity of the line must evaluate and remediate, as necessary, all pipeline segments (**both covered and non-covered**) with similar material coating and environmental characteristics.
    - FAQ-135 states "that could adversely affect the integrity of the line" means an immediate repair condition in accordance with 192.933. In other words, this requirement applies if the operator finds corrosion metal loss resulting in a Pf <1.1 times MAOP (192.933(d)).
- For every immediate repair corrosion condition (i.e., for every condition meeting the criterion in 192.933(d)(1)(i)), the operator must document evaluations to identify other potentially affected pipeline segments. Such evaluations must consider all pipe with similar material coating and environmental characteristics. The operator must document its plans for remediating other conditions found as a result of these evaluations. Inspections should identify selected immediate corrosion conditions and perform a review of these required analyses.
- Operators should establish and maintain a schedule for evaluation and remediation of, as necessary, the similar segments consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.
- Provisions for establishment and maintenance, including change control provisions, of the schedule should be documented in he operator's IMP.
- Implicit in this requirement is that the operator's evaluation determines the root cause of the condition. Clearly in most cases, it would not be practical to excavate all pipelines with similar coating and environmental characteristics. This suggests that the evaluation further refine the criteria by which other portions of the line will be investigated or excavated.
    - For example, if the root cause was poor disbonded coating, an ACVG or DCVG Survey might be planned to determine the extent of coating damage and investigate areas of poor coating. If the defect was discovered based on ECDA, the indirect assessment logs may need to be re-graded and further excavations performed.
- Kiefner has developed the following flowchart for determining the adequacy of corrosion control - Supplemental Guidance Appendix H.06. Inspectors should also consider whether other unique circumstances (e.g., stray currents from power lines sharing right of way) need to be taken into account.

Corrosion Control Adequacy Test Flowchart



H.07 Automatic Shut-Off Valves or Remote Control Valves

Verify that the operator has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. [§192.935(c)]

H.07.a. Verify that an adequate risk analysis-based process is used to determine if an automatic shut-off valve or remote control valve should be added. [§192.935(c)]

i. Verify that, as a minimum, the following factors were considered: [§192.935(c)]
   1. swiftness of leak detection and pipe shutdown capabilities
   2. the type of gas being transported
   3. operating pressure
   4. the rate of potential release
   5. pipeline profile
   6. the potential for ignition
   7. location of nearest response personnel

H.07.a. Supplemental Guidance:

- 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 following factors must be included in the process:
  - 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
  - location of nearest response personnel
- Inspectors should review examples of implementation of the process to determine the appropriateness of conclusions reached on the need for, or lack of need for, the installation of automatic shut-off valves or remote control valves.
- FAQ-86 affirms the rule requirement that an operator is required to install an ASV or RCV if the operator determines that it would be an efficient means to protect an HCA in the event of a gas release.
- Supplemental Guidance Appendix H.02, Use of Remote Controlled Main Line Valves, provides a summary of an industry report that analyzes the cost benefit of RCV installation (GRI-98/0076, Cost Benefit Study of Remote Controlled Main Line Valves - Reference: RCVCB). PHMSA anticipates that many operators will use this report as the technical justification for not adding additional valves. Inspectors should familiarize themselves with the report, which indicates that RCV installation may not be cost effective from a safety perspective since, in most cases, injury or death occurs so near to the time of pipeline rupture that RCVs may not respond quickly enough.
- PHMSA Technical report, Remotely Controlled Valves on Interstate Natural Gas Pipelines, September 1999 (Reference: RCVF), is a feasibility study conducted by PHMSA regarding the potential need for requirements associated with the use of RCVs. This study concludes that RCVs operate reliably, provide some reduction in risk, and can be installed in a technically adequate way. The study also references the cost-benefit study by GRI (Supplemental Guidance Appendix H.02) as a reasonable basis for concluding that installation of RCVs is not cost effective. In some instances, the risk reduction gained may validate the need for RCVs.
- Note that system-wide or generic studies for RCVs/ACVs may be used by an operator as long as the operator documents the reason why the study is applicable to the segment-specific conditions.
- Operators may consider the addition of RCVs/ACVs in right-of-way areas with high voltage transmission lines due to the increased likelihood of ignition.

H.08 General Requirements (Implementation of Additional Measures)

Verify that the operator has identified and implemented (or scheduled) 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: [§192.935(a)]

H.08.a. Verify that a systematic, documented decision-making process is in place to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. [§192.935(a)]

H.08.a. Supplemental Guidance:

- The operator's IMP should include a systematic, documented decision-making process to decide which measures are to be implemented. The process should include input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. Preventive and mitigative measures that are proposed to reduce specific identified risks are best developed or specified by the parts of the organization that have the most knowledge of the areas under evaluation.
- As an example, preventive and mitigative measures for pipelines that are susceptible to corrosion should be strongly influenced by the corrosion control technical staff, while decisions regarding EFRDs and Leak Detection would be strongly influenced by the controls technical staff and operations personnel.
- Each operator is likely to 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.
    - Additionally, both the decision-making process and the basis for decisions must be documented as part of the operator's IM plan. Decisions that must be documented include:
        - Selection of candidate P&M measures for consideration
        - Decisions about which candidate measures to implement (or not implement)
        - Reason(s) for decisions made, including the decision's anticipated affect on pipeline risk
        - Schedule for implementation and other implementation plans
    - It would be expected that certain core groups would be involved in the preventive and mitigative decision making process – Operations, Maintenance, Corrosion Control, Engineering, Planning, and Project Management.

H.08.b. Verify that the decision-making process considers both the likelihood and consequences of pipeline failures. [§192.935(a)]

H.08.b. Supplemental Guidance:

- Inspection should review the operator's IMP and verify that the decision-making process considers both the likelihood and consequences of pipeline failures. Clearly, segments and facilities that represent the highest risk are the most important candidates for additional preventive and mitigative actions. Therefore, the inspection team should determine if additional actions have been evaluated for the highest risk segments/facilities as indicated by the risk analysis.
- "**SHOULD** REQUIREMENT: The risk drivers for each high risk segment **should** be considered in determining the most effective mitigation option. (Refer to ASME B31.8S-2004, Section 5.11.) [Re: Protocol L.03] Inspectors should verify that the operator understands the risk analysis results sufficiently to determine which factors affect risk the most (i.e., the "risk drivers") and select

preventive and mitigative measures that affect the dominant risk factors. The use of gross or overall risk scores for determining P&M measures, while important, may not contain enough information to identify the most effective candidate measures for reducing risk.
- While the evaluation may or may not result in any actions being implemented, it is important to determine if the operator's process gives priority to the highest risk portions of the pipeline.

H.08.c. Verify that additional measures are identified and documented and have actually been implemented, or scheduled for implementation. [§192.935(a)]

H.08.c. Supplemental Guidance:

- Inspection should verify that additional measures are identified and documented and have actually been implemented, or scheduled for implementation. The preventive and mitigative actions decision process should also describe how actions that meet the criteria to be implemented are actually being accomplished in the field. It is expected that most operators will use existing company work processes to implement the additional actions. To implement a planned preventive and mitigative action may require coordination of Engineering, Maintenance, Operations, Planning and Budget, and Project Management, to name a few.
- It is likely that some additional actions that are implemented will be non-hardware work process/procedural changes that might be implemented by a different company process than for physical changes/modifications. If possible, both physical and non-physical types of changes should be assessed to verify that the additional actions are actually implemented or scheduled for implementation.
- In most cases, the non-hardware changes can be handled in a more direct manner than physical changes to the pipeline and its systems, and should be relatively straightforward to implement. In the case of hardware changes, however, modifications are often scheduled around budget cycles and/or operational constraints. In both cases, however, it is important to determine how the operator is planning and scheduling the additional actions.

Protocol Area I. Performance Measures

- I.01 General Performance Measures
- I.02 Performance Measures Records Verification
- I.03 Exceptional Performance Measurements
- Table of Contents

I.01 General Performance Measures

Inspect the operator's program to verify that, as a minimum, provisions exist for measuring integrity management program effectiveness in accordance with the four elements of ASME B31.8S-2004, Section 9.4 and each identified threat in ASME B31.8S-2004, Appendix A. [§192.945(a) and ASME B31.8S-2004, Section 12(b)(5)]

I.01 *Supplemental Guidance:*

- Two types of performance measures are required of all operators. Both types of measures are to be taken by the operator on a semi-annual basis and the ending dates are the same for all operators: June 30th and December 31st:
    - The four overall program measures required by ASME B31.8S-2004, Section 9.4 (see Protocol I.01.a); and
    - Threat-specific metrics as given in ASME B31.8S-2004, Appendix A.
- Program documentation should specify that the measures are to be taken and should identify the specific dates the measures should cover.

- The first set of measures is specifically called out by the standard. Measures from the second set will only apply if the operator has determined that the threat of concern applies to their pipeline.
- Evidence should exist that demonstrates the operator has taken action to determine which of the ASME B31.8S-2004, Appendix A threats apply to its pipeline.
- Threat-specific program measures are NOT required to be reported to PHMSA or the applicable Interstate Agent.
- FAQ-136 states that the terms leaks, failures, and incidents are defined in ASME B31.8S-2004, Section 13. Operators should apply the definitions in the standard when reporting their performance measures.
- FAQ-137 clarifies that operators should report the number of events (e.g., miles of pipe inspected, scheduled repairs completed) occurring within each six month reporting period.
- FAQ-159 clarifies that incidents are as defined for incident reporting in 49 CFR 191.3. PHMSA expects, however, that operators deviating from the requirements of prescriptive programs on the basis of "exceptional performance" under 192.913(b) will evaluate events that involve unintentional release of gas but which do not reach the reporting threshold.
- FAQ-186 provides guidance on how the use of prior assessments and the associated HCA segment mileage can be included in semi-annual performance measure submittals.

I.01.a. Verify that performance is measured semi-annually (completed through June 30th and December 31st of each year) for each of the following: [ASME B31.8S-2004, Section 9.4]

- Number of miles of pipeline inspected versus program requirements
- Number of immediate repairs completed as a result of the integrity management inspection program
- Number of scheduled repairs completed as a result of the integrity management program
- Number of leaks, failures and incidents (classified by cause).

I.01.a. Supplemental Guidance:

- The four overall performance measures required by ASME B31.8S-2004, Section 9.4 are as follow:
    - Number of miles of pipeline inspected versus program requirements.
    - Number of immediate repairs completed as a result of the integrity management inspection program.
    - Number of scheduled repairs completed as a result of the integrity management program.
    - Number of leaks, failures and incidents (classified by cause).
- The operator's program documentation should identify that these measures are to be taken semi-annually, with the data periods being:
    - January 1 through June 30, and
    - July 1 through December 31 of each year.
- The fourth of these metrics indicates that leaks, failures, and incidents measured are to be classified by their attributed cause.
- Evidence should be available that these four metrics have been taken, with the first period ending as of June 30, 2004. Failure to have these measurements on hand could be considered a violation.
- Each operator of gas transmission pipelines must submit performance metrics semi-annually whether they had any covered segments or not. This is so PHMSA is aware the operator is still looking for new HCAs and has not found any. PHMSA cannot assume that old information is still valid, since population growth or land use changes could result in new HCAs. Therefore, operators have to make a report each reporting period, even if they have no covered segments.

I.01.b. Verify that performance is measured semi-annually in accordance with the threat-specific metrics of ASME B31.8S-2004, Appendix A (See ASME B31.8S-2004, Table 9 for a summary listing).

I.01.b. Supplemental Guidance:

- Threat-specific measures are identified in ASME B31.8S-2004, Appendix A and the following table. The operator's program procedures or framework documentation should indicate the need for determining applicable threats and use of the applicable metrics from this table. Note that these metrics should be considered to be the minimum required set.

Threat-Specific Measures as Identified in ASME B31.8S-2004, Appendix A:

External Corrosion Threats ASME B31.8S-2004, Appendix A, Section A1.8	(a) Number of hydrostatic test failures caused by external corrosion (b) Number of repair actions taken due to in-line inspection results, immediate and scheduled (c) Number of repair actions taken due to direct assessment results, immediate and scheduled (d) Number of external corrosion leaks (for low stress pipelines it may be beneficial to compile leaks by leak classification)
Internal Corrosion Threats ASME B31.8S-2004, Appendix A, Section A2.8	(a) Number of hydrostatic test failures caused by internal corrosion (b) Number of repair actions taken due to in-line inspection results, immediate and scheduled (c) Number of repair actions taken due to direct assessment results, immediate and scheduled (d) Number of internal corrosion leaks (for low stress pipelines it may be beneficial to compile leaks by leak grade)
Stress Corrosion Cracking ASME B31.8S-2004, Appendix A, Section A3.6	(a) Number of in-service leaks/failures due to SCC (b) Number of repair or replacements die to SCC (c) Number of hydrostatic test failures due to SCC
Manufacturing ASME B31.8S-2004, Appendix A, Section A4.8	(a) Number of hydrostatic test failures caused by manufacturing defects (b) Number of leaks due to manufacturing defects
Construction ASME B31.8S-2004, Appendix A, Section A5.8	(a) Number of leaks or failures due to construction defects (b) Number of girth welds/couplings reinforced/removed (c) Number of wrinkle bends removed (d) Number of wrinkle bend inspections (e) Number of fabrication welds repaired/removed
Equipment ASME B31.8S-2004, Appendix A, Section A6.8	(a) Number of regulator valve failures (b) Number of relief valve failures (c) Number of gasket or O-ring failures
Third Party Damage ASME B31.8S-2004, Appendix A, Section A7.8	(a) Number of leaks or failures caused by third party damage (b) Number of leaks or failures caused by previously damaged pipe (c) Number of leaks or failures caused by vandalism (d) Number of repairs implemented as a result of third party damage prior to a leak or failure
Incorrect Operations ASME B31.8S-2004, Appendix A, Section A8.8	(a) Number of leaks or failures caused by incorrect operations (b) Number of audits/reviews conducted (c) Number of findings per audit/review classified by severity (d) Number of changes to procedures due to audit/reviews
Weather / Outside Force ASME B31.8S-2004, Appendix A, Section A9.8	(a) Number of leaks that are weather related or due to outside force (b) Number of repair, replacement, or relocation actions due to weather related or outside force threats

- The periodicity for taking these measures is the same as for the four overall program measures cited in Protocol I.01.a with the same end dates of each June 30th and each December 31st.
- Documentation must be available that the applicable metrics of this set have been determined and the appropriate measures taken, with the first period ending as of June 30, 2004. Failure to have these measurements on hand could be considered a violation.
- It would also be expected that operators periodically review their threat listing to make sure that any new threats identified result in the appropriate expansion of the list of performance measures to be taken.

I.02 Performance Measures Records Verification

Inspect operator records to verify: [§192.945(a)]

I.02 *Supplemental Guidance:*

- Protocol I.02 is directed at the records generated by the operator during the performance measuring process.
- Records should confirm that the specified set of performance measures are, in fact, being taken and reported in a timely manner.

I.02.a The four overall performance measures of ASME B31.8S-2004, Section 9.4 have been submitted to PHMSA on a semi-annual basis in accordance with §192.951. Note: Initial report by August 31, 2004, semi-annual reports by February 28th (or 29th) and August 31st of each year thereafter. [§192.945(a)]

I.02.a Supplemental Guidance:

- The Rule requires submittal of the four overall performance measures in ASME B31.8S-2004, Section 9.4 within two months of completion of a measuring period.
- Each operator of gas transmission pipelines must submit performance metrics semi-annually whether they had any covered segments or not. This is so PHMSA is aware the operator is still looking for new HCAs and has not found any. PHMSA cannot assume that old information is still valid, since population growth or land use changes could result in new HCAs. Therefore, operators have to make a report each reporting period, even if they have no covered segments.
- Both the measuring period completion dates and the reporting dates are specified and there are no exceptions provided by the Rule. Measuring period completion dates are June 30th and December 31st of each year, making the reporting dates August 31st and February 28th (or 29th) for each respective period.
    - FAQ-137 clarifies that operators should report the number of events (e.g., miles of pipe inspected, scheduled repairs completed) occurring within each six month reporting period. The rule requires that the measures cover a six-month period, ending June 30 and December 31, and be reported within two months after those dates.
    - The operator is to have submitted their first report of program measurements by August 31, 2004.
- There are three methods of acceptable reporting:
    - electronic - preferred method. See FAQ-194
    - fax, and
    - mail
    - The e-mail address, fax number and mailing address for performance measure reports are found in §192.951 of the Rule.
- Operators are required by the Gas IM Rule to report performance metrics semi-annually, by the end of August and the end of February. It is preferred that the report be filed electronically through the Gas IM Public Website.

- Inspectors should review the reports submitted by the operator to verify the accuracy of the reported data and to question, investigate, or sample data to learn if they under-reported (i.e., failed to report all of the items they were required to report).
- Instructional guidance to operators online. For convenience, it is shown in Supplemental Guidance Appendix I.01, Instructions for Semi-Annual Reporting of Performance Measures via the PHMSA Online Data Entry System.
- The Rule requires the initial report of the four basic metrics from ASME B31.8S-2004, Section 9.4 be submitted on August 31, 2004. This requirement was amended by Advisory Bulletin ADB-04-02, Semi-annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management, July 22, 2004 (Reference: ADB-0402). Since operators may not have had time to determine the full scope of applicable pipeline, required repairs, etc., the required date for the first report was deemed premature to some extent. Therefore, operators were allowed to instead report that they had begun assessment activities by June 17, 2004, in conformance with the Pipeline Safety Improvement Act of 2002.
- Advisory Bulletin ADB-05-01 Semi-annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management, January 21, 2005 (Reference: ADB-0501), was later issued to inform operators that sufficient time had passed by the due date of the second required performance measure report (February 28, 2005) so that quantitative information must be included in that report and in all subsequent reports. Further, this second report was expected to include all data covering calendar year 2004.
- Operators are encouraged to report quantitative measures separately for each state. Current Rule requirements do not specify that operators must file separate reports for each state in which they operate gas transmission piping. However, state pipeline safety authorities will have significant involvement in oversight of the implementation of integrity management requirements for gas transmission pipelines and performance measure information for their state will be useful for prioritizing and managing this work. A rule modification is being contemplated to require performance measure reporting on a state-by-state basis.

I.03 Exceptional Performance Measurements

For operators that choose to demonstrate exceptional performance in order to deviate from certain requirements of the rule, verify the following.

I.03 *Supplemental Guidance:*

- Protocol I.03 provides inspection guidance for those operators using the Exceptional Performance provisions of the rule. If an operator desires to deviate from certain requirements of the Rule, it may do so by implementing a program that demonstrates exceptional performance as provided for by §192.913.
- Part of the provisions of being designated an exceptionally performing program includes the development and implementation of program measures in addition to those normally required of all operators (i.e., those specified in ASME B31.8S-2004, Section 9.4 and ASME B31.8S-2004, Appendix A).
- An operator must have defined these additional measures and be able to demonstrate the process by which these additional metrics determined and why they are useful.
- The operator must be engaged in taking the measures and reporting them to PHMSA (or the applicable Interstate Agent or other local/state pipeline safety authority).

I.03.a. Additional performance measures beyond those required in §192.945 (see Protocol I.01) are part of the operator's performance plan. [§192.913(b)(vii)]

I.03.a. Supplemental Guidance:

- There are no specific guidelines on what would constitute appropriate additional program measures for the exceptionally performing program. The operator who chooses to implement an exceptional program plan, must as part of that plan define the set of measures that provide useful information to their unique plan. It is only specified that these measures must go beyond those already required by ASME B31.8S-2004, Section 9.4 and the applicable threat specific measures of ASME B31.8S-2004, Appendix A.
- If the operator uses ECDA, there will be a set of program measures specifically for that aspect of its program as well. Exceptional program measures would be in addition to the ECDA measures as well.
- The measures are to be taken semi-annually. There is no specification that the exceptional measures be taken for the same period as the other required measures, i.e., taken every June 30th and taken every December 31st.

I.03.b. All performance measures (all measures required by §192.945 and the additional performance measures) are submitted to PHMSA on a semi-annual frequency in accordance with §192.951. [§192.913(b)(vii)]

I.03.b. Supplemental Guidance:

- The reporting of exceptional program measures to PHMSA (or the Interstate Agent) is to be accomplished semi-annually, similar to reporting of the four overall program measures. However, the same deadlines for report filing are not specified in the rule.
- There are three methods of acceptable reporting:
    - electronic - preferred method. See FAQ-194
    - fax, and
    - mail
    - The e-mail address, fax number and mailing address for performance measure reports are found in §192.951 of the Rule.
- Operators are required by the Gas IM Rule to report performance metrics semi-annually, by the end of August and the end of February. It is preferred that the report be filed electronically through the Gas IM Public Website. Instructional guidance to operators is provided in Supplemental Guidance Appendix I.01, Instructions for Semi-Annual Reporting of Performance Measures via the PHMSA Online Data Entry System.
- FAQ-209 clarifies that the rule requires semi-annual submission of only the four overall measures as specified by ASME B31.8S-2004, Section 9.4. Operators implementing performance-based programs, under §192.913, are required to submit the additional performance measures they define for their programs in addition to the ASME B31.8S-2004, Section 9.4 measures.

Protocol Area J. Record Keeping

- J.01 Records to be Maintained by the Operator
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J.01 Records to be Maintained by the Operator

Verify that the following records, as a minimum, are maintained for the useful life of the pipeline: [§192.947, ASME B31.8S-2004, Section 12.1 and ASME B31.8S-2004, Section 12.2(b)(1)]

***J.01** Supplemental Guidance:*

Numerous records are generated as a result of Integrity Management Program Implementation. To the extent that these records demonstrate compliance with Rule requirements, they are to be maintained by the operator such that they are readily retrievable, protected from damage, and secured sufficiently to prevent unauthorized use.

- 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.
- 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 is some sort of formalized or structured record-keeping system, as opposed to individual working files.
- As an alternative to each procedure specifying recordkeeping requirements, a single procedure that specifies all recordkeeping requirements would be considered sufficient programmatic control.
- Records retained should be in good condition, legible, readily retrievable, properly secured, and properly completed (i.e., no missing signatures or dates when necessary to demonstrate compliance with the rule)
- FAQ-165 states that information in an electronic database is considered satisfactory documentation. An operator should be prepared to discuss evidence demonstrating that the database was used as a contemporary record, rather than having been created after the fact. Procedures, historical printouts, and archived copies of the database are examples of means that can be used to demonstrate that the database is relevant documentation.

J.01.a. i. A written integrity management program [§192.947(a)]

ii. Threat identification and risk assessment documentation per §192.917 [§192.947(b)]
iii. A written baseline assessment plan per §192.919 [§192.947(c)]
iv. 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 [§192.947(d)]
v. Training program documentation and training records per §192.915 [§192.947(e)]
vi. Remediation schedule and technical basis documentation per §192.933 [§192.947(f)]
vii. Direct assessment plan documentation per §192.923 through §192.929 [§192.947(g)]
viii. Confirmatory assessment documentation per §192.931 [§192.947(h)]
ix. Documentation of Notifications to PHMSA or State/Local Regulatory Agencies. [§192.947(i)]

J.01.a. Supplemental Guidance:

- The operator's integrity management program should exist in the form of a program description including reference to the appropriate set of implementing procedures.
    - FAQ-238 clarifies the level of detail expected in operator IM process descriptions.
    - FAQ-189 states that operators should exercise appropriate controls to ensure that their IM programs, and the procedures by which its elements are implemented, are approved for use. The level of management official responsible for that approval is up to each operator, but should be at a level sufficient to assure compliance.
    - Referenced procedures or any other documents the operator maintains as the overall description of their program should be retrievable, in good condition, legible, properly secured, and protected from damage.
    - Earlier revisions to the program should be included in document files as archived information. Evidence should be included as to why any program documents have been revised and the effective date of the revisions.
    - FAQ-32 states that operators should maintain, for the useful life of the pipeline, 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. Copies of the evolving revisions of the baseline assessment plan, and of plans for periodic reassessments, should be included with the records maintained under this section.
- The operator's procedures for the identification of threats and assessment of risk to covered pipeline segments should indicate the requirement to keep permanent records of the results of the identification and analysis process.
    - Any procedures or guidance for threat identification and risk assessment should be on hand, as well as the results of the process.
    - Periodic updates to risk assessment documentation would also be expected in program files, including documents that demonstrate integration of risk information, and include supporting records such as meeting minutes of subject matter expert reviews where conclusions are drawn.
- The baseline assessment plan and all revisions should be available for inspection. The reason for any revisions to the plan should be clearly documented.
    - FAQ-32 requires that operators maintain, for the useful life of the pipeline, 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. Copies of the evolving revisions of the baseline assessment plan, and of plans for periodic reassessments, should be included with the records maintained under this section.
- The Rule requires that 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 be maintained.
    - This set of documents includes 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.
    - This set of documents is potentially very broad, but is intended to focus on those documents that provide a technical justification for decisions made concerning or affecting the integrity of the pipeline.
    - In the event that the operator cannot produce documentation that demonstrates this technical justification, the absence of a record of decision could be a violation of rule requirements.
    - FAQ-239 clarifies that justifications of decisions must include a technical rationale for the decision, and not simply record the decision that was made.

- Employee qualification requirements should be available in a form that resembles job descriptions or a job task analysis.
    - In addition, evidence should be available that demonstrates that the employees filling the jobs described meet the qualification requirements. This could include resumes, but might also include training rosters where additional training is necessary.
    - Evidence of mentoring should be documented where that approach is used to qualify an individual.
    - Vendor qualifications should be documented through contractual documentation. Accepted proposal documentation may serve as evidence that the vendor is providing the appropriately qualified personnel to assess ILI results.
- Records for remediation activities are to be retained for the lifetime of the pipeline.
    - Records for remediation activities should include schedule information, including date of discovery of anomalies, and demonstrate repair (when appropriate) in accordance with the appropriate set of code requirements.
    - Records of pressure reductions should be available, including those which determine the revised operating pressure limits, as well as those that indicate the date by which the reduction occurred.
    - Operators should retain evidence that documents the decision of the proper approach for remediation.
- Direct assessment records should be available for inspection.
    - Since direct assessment is an alternate approach to ILI, the same set of decision documentation as well as excavation documents should be retained.
    - All records should demonstrate the appropriate level of approval and record dating should support rule requirements.
- Records associated with conducting confirmatory assessments should be retained by the operator.
    - Records associated with conducting confirmatory assessments include excavation documentation as well as decision documentation that identifies where confirmatory assessment is to be conducted.
    - Records should be comprehensive, and should show review and concurrence by affected parties.
- Evidence that the appropriate regulatory authority has been notified in accordance with the various requirements of the Rule must be retained by the operator.
    - The date of notification and the method of notification should be apparent.
    - The use of electronic notification is preferred, therefore such records are acceptable evidence.

Protocol Area K. Management of Change (MOC)

- K.01 Documentation and Notification of Changes to the Integrity Management Program
- K.02 Attributes of the Change Process
- Table of Contents

K.01 Documentation and Notification of Changes to the Integrity Management Program

Verify that changes to the integrity management program have been handled in accordance with §192.909 of the rule.

K.01 *Supplemental Guidance:*

- It is an acceptable practice for an operator to revise its integrity management program, however, changes must be accomplished in a controlled manner. The program documentation, framework, procedures, etc., must first be revised before the change can be implemented.
- With each revision, the operator must identify and justify the need for the change. This may be done relatively simply with a revision log for the document.

    - FAQ-201 clarifies that an operators' management of change process should be implemented as soon as there is a program whose change needs to be managed.
- After revisions are made to the program document, then it is appropriate for the operator to implement the change. The inspector may choose to determine if the change affects qualification and training requirements for those involved in implementing the integrity management program. If so, it may be confirmed that the affected personnel have received the appropriate qualification training.
- PHMSA (and the Interstate Agent as applicable) is to be notified of significant program changes within 30 days after the change has been implemented.
    - FAQ-97 addresses the types of changes requiring notification. Only significant changes require notification.
    - FAQ-98 addresses the timing for submittal of required notifications.
    - FAQ-99 addresses the information that must be included in a notification. Notifications must provide enough information for PHMSA to understand the reason for the deviation/change from the actions specified in the rule.
- It is not the intent that every program change be communicated in accordance with this requirement. Some judgment must be used in considering whether the change is "significant". Examples of significant changes are:
    - Merger of companies or major acquisition of pipeline.
    - Determination of susceptibility to SCC when previously considered unsusceptible.
    - Introduction of an assessment methodology not previously used.
    - Abandoning an assessment methodology previously planned for use.
    - FAQ-111 addresses what level of change satisfies the terms "significantly modify" or "substantially affect" as used under subpart 192.909(b)
- Examples of changes that would not be considered significant and would not require notification are:
    - Addition of new HCA segments.
    - Reprioritization of remediation actions that do not result in noncompliance with the Rule.
    - Reprioritization of preventive or mitigative measures.
    - Reprioritization of assessments due to updated risk analysis.
    - Use of a different model for ICDA than the one referenced in the rule.
        - FAQ-153 clarifies that notification is not required if an operator uses a different model for ICDA than the one referenced in the rule.

K.01.a. Verify that the reasons for program changes have been documented prior to implementation of the change(s). [§192.909(a)]

K.01.a. Supplemental Guidance:

- The Rule requires program revision before a change to the program is implemented. This demonstrates a properly controlled change and helps ensure affected personnel are properly notified.
- The inspector should be able to locate program changes via a revision log or some other properly documented notification.
    - FAQ-201 clarifies that an operators' management of change process should be implemented as soon as there is a program whose change needs to be managed.
- If no documentation exists to describe and justify the change, then the change is not being properly managed.
- Proper authorization should also be evident on the changed documentation. The operator should have program changes approved by the same authority that approved the original program.

K.01.b. Verify, that for significant changes to the program, program implementation, or schedules, PHMSA and the State or local pipeline safety authority, if applicable, has been notified within 30 days after the operator has adopted the change. [§192.909(b)]

K.01.b. Supplemental Guidance:

- PHMSA and appropriate state or local authority is to be notified in accordance with the provisions of §192.949 of the Rule any time it changes its integrity management program in a significant way.
    - FAQ-111 specifically addresses what constitutes significant changes.
- PHMSA does not desire to receive numerous program revision notifications for minor or expected program revisions. The examples presented in Protocol K.01 may provide some insight on what is significant vs. insignificant.

K.02 Attributes of the Change Process

Verify that the integrity management program meets the requirements of ASME B31.8S-2004, Section 11 for a management of change process. [§192.911(k)]

K.02 *Supplemental Guidance:*

- ASME B31.8S-2004, Section 11 contains the provisions for what constitutes an acceptable management of change process.
- Operators may have a special set of procedures that describe change control as it applies to integrity management, or it may have an existing change control process that incorporates the aspects of integrity management.
- The management of change process specified in ASME B31.8S-2004, Section 11 addresses both program changes and physical/design changes. It should be noted that changes in the integrity management program can drive physical changes to the pipeline, and changes to the pipeline can affect the integrity management program in areas like risk analysis and assessment methods.

K.02.a. Verify the existence of procedures that consider impacts of changes to pipeline systems and their integrity. [ASME B31.8S-2004, Section 11(a)]

K.02.a. Supplemental Guidance:

- ASME B31.8S-2004, Section 11 requires procedures to be in place to control changes such that the affect on pipeline integrity is considered. This could be implemented by ensuring the appropriate review of proposed changes by pipeline integrity personnel.
- Examples of changes that must be considered include, but are not limited to:
    - New gas streams coming online (for example, new wells) that increase the BTU heat value of the transported gas (change from lean to rich gas)
    - Pipeline reroutes that place the pipeline closer to identified sites
    - An increase in pipeline MAOP that results in a larger potential impact circle
    - Pipeline modifications affecting piping diameter that results in a larger potential impact circle
    - Corrections to erroneous pipeline center line data

K.02.b. Verify change procedures address technical, physical, procedural, and organizational changes. [ASME B31.8S-2004, Section 11(a)]

K.02.b. Supplemental Guidance:

- Procedures must ensure all aspects of change are considered, including technical, physical, procedural, and organizational changes.
- **"SHOULD"** Requirement: The process should incorporate planning for each of these situations and consider the unique circumstances of each. Re: ASME B31.8S-2004, Section 11(a) and Protocol L.03]
- Inspectors should consider if all relevant aspects of a particular change were addressed.

K.02.c. Verify the following are provided for by the change procedures: [ASME B31.8S-2004, Section 11(a)]

i. Reason for change
ii. Authority for approving changes
iii. Analysis of implications
iv. Acquisition of required work permits
v. Documentation
vi. Communication of the change to affected parties
vii. Time limitations
viii. Qualification of staff

K.02.c. Supplemental Guidance:

- The following eight considerations must be provided for by management of change procedures and exhibited on any changes reviewed:
    - Reason for change.
    - Authority for approval.
    - Analysis of implications.
    - Acquisition of required work permits.
    - Documentation of the change.
    - Communication of the change to affected parties.
    - Time limitations.
    - Qualification of staff involved in the change.

K.02.d. Verify that integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. [ASME B31.8S-2004, Section 11(b)]

K.02.d. Supplemental Guidance:

- Program changes, such as making decisions that impact preventive and mitigative measures can also affect physical attributes in the field.
- Changes must be examined to confirm that field impacts were implemented along with program changes. The inverse is also true, namely, field changes can have impact on the integrity management program. Decisions to modify or replace piping can have a positive impact on risk ranking of HCA segments, but would also give higher priority to other segments. This two-way impact of a change should be considered by the inspector.

K.02.e. Verify that equipment or system changes have been identified and reviewed before implementation. [ASME B31.8S-2004, Section 11(d)]

K.02.e. Supplemental Guidance:

- It is a fundamental and sound requirement that any changes considered to either the program or to physical features be fully evaluated for impact prior to implementing the change.
- Part of complying with this aspect of the Rule is ensuring that broad review of changes is accomplished by potentially affected parties.
- Omission of an essential discipline in the review process could be evidence of a systemic problem and should be investigated.

Protocol Area L. Quality Assurance

- L.01 Program Requirements for the Quality Assurance Process
- L.02 Personnel Qualification and Training Requirements
- L.03 Invoking Non-Mandatory Statements in Standards
- Table of Contents

L.01 Program Requirements for the Quality Assurance Process

Verify that a quality assurance process exists that meets the requirements of ASME B31.8S-2004, Section 12. [§192.911(l)]

L.01 *Supplemental Guidance:*

- ASME B31.8S-2004, Section 12 states the provisions for an acceptable quality assurance process, also called a quality control plan.
- Quality control is defined in the standard as "documented proof that the operator meets all the requirements of their integrity management program."
- Some operators may already have a quality assurance process that meets ASME B31.8S-2004, Section 12 of the standard and therefore only need to incorporate the elements of their integrity management program into their existing program.
- ASME B31.8S-2004, Section 12.2 identifies six activities that provide a broad perspective on the concept of applying quality to programs or processes. The operator's QA program should embrace these activities and the operator should be able to demonstrate to the inspector how these activities are conducted within their documented approach. The following six elements are quoted from the standard as normally required for an effective QA process:
    - Identify the processes that will be included in the quality program.
    - Determine the sequence and interaction of these processes.
    - Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.
    - Provide the resources and information necessary to support the operation and monitoring of these processes.
    - Monitor, measure, and analyze these processes.
    - Implement actions necessary to achieve planned results and continued improvement of these processes.
- Specific areas where the QA program should be visible are identified in the Protocol L.01.a through Protocol L.01.d.
- Third-party reviews are identified in ASME B31.8S-2004, Section 12.2(b)(6), but these are only recommended activities and are therefore not listed below.
- FAQ-76 describes the elements than must be included in an operator's IMP, one of which is a quality assurance program.

- **"SHOULD"** Requirement: Periodic internal audits of the integrity management program and its quality plan are recommended. An independent third-party review of the entire program may be useful. [Re: ASME B31.8S-2004, Section 12.2(b)(6) and Protocol L.03]

L.01.a. Verify that responsibilities and authorities for the integrity management program have been formally defined. [ASME B31.8S-2004, Section 12.2(b)(2)]

L.01.a. Supplemental Guidance:

- Documented responsibilities and authorities must exist for the various elements of the integrity management plan, including those responsibilities and authorities for implementing the QA plan. These may be found in job descriptions for applicable personnel or in procedures or other program documentation, and should be clear and unambiguous.

L.01.b. Verify that reviews of the integrity management program and the quality assurance program have been specified to be performed on regular intervals, making recommendations for improvement. [ASME B31.8S-2004, Section 12.2(b)(3)]

L.01.b. Supplemental Guidance:

- Regularly scheduled program reviews must be identifiable in program documentation and conducted by the operator.
- These reviews must examine the effectiveness of the integrity management program and the effectiveness of the QA process with recommendations for improvement where necessary.
- Overall goals for both processes should be defined, agreed to by management, and implemented through program processes.
- Follow-through on program corrections should be examined by the inspector.
- §192.907(a) requires that each operator make continual improvements to the program. This requirement is discussed further in Supplemental Guidance Appendix L.01, White Paper, Continuing Improvement.

L.01.c. Verify that corrective actions to improve the integrity management program and the quality assurance process have been documented and are monitored for effectiveness. [ASME B31.8S-2004, Section 12.2(b)(7)]

L.01.c. Supplemental Guidance:

- A viable corrective action process is a fundamental element of an effective QA process and therefore is a required element.
- Corrective actions must be documented and, after implementation, monitored for effectiveness in correcting the deficiency or area in need of improvement.
- Although not explicitly required in the standard, an effective corrective action process should:
    - Promptly identify and correct deficiencies in the integrity management program, and identify/resolve any generic implications to other similar activities or features.
    - Require the investigation of the root cause of any significant condition adverse to quality or program deficiency, and specify the appropriate actions to prevent recurrence to address the root cause.
    - Engage in tracking to completion those activities that resolve the condition adverse to quality, with appropriate timeliness considerations included.

L.01.d. Verify that when an operator chooses to use outside resources to conduct any process that affects the quality of the integrity management program, the operator ensures the quality of such processes and documents them within the quality program. [ASME B31.8S-2004, Section 12.2(c)]

L.01.d. Supplemental Guidance:

- When an operator chooses to use outside resources to conduct any process, for example pigging, that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program. This type of control would be expected to be used through contractual vehicles, so an examination of the contract may be necessary during an IMP inspection.
- Documentation of such processes may entail the use of tracking systems and issue resolution procedures set up between the operator and the contractor/vendor. Inspectors should review any such documents established as part of the operator's QA program. If the operator has not established this documentation, more detailed investigation may be needed in order to ascertain if/how the operator is ensuring the quality of processes implemented by outside resources.
- Contractual language by itself will not demonstrate compliance by the outside resources. A review of contractor deliverables, work products, or other documents may be necessary to confirm that the vendor is implementing the requirements.

L.02 Personnel Qualification and Training Requirements

Verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. [§192.911(l), §192.915 and ASME B31.8S-2004, Section 12(b)(4)]

***L.02** Supplemental Guidance:*

- 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.
- An approved listing of what constitutes the minimum set of qualification requirements for the various functions to be performed in an integrity management program does not exist although some regulatory effort is being made to identify that set. Inspectors must rely on the list of qualification requirements provided by the operator, but should expect the operator to defend the list. Once the list is agreed upon, the inspector should examine personnel records to confirm that those filling a position having qualification requirements meet those requirements.
- Resumes, training certificates, or class attendance rosters may all serve as acceptable demonstration that qualification requirements are met.
- The inspector should be aware of any re-qualification requirements and ensure that the operator's personnel are up-to-date with re-qualification.

L.02.a. Verify that the Integrity Management Program requires supervisory personnel to have the appropriate training or experience for their assigned responsibilities. [§192.915(a)]

L.02.a. Supplemental Guidance:

- 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.
- Tracking of qualification deficiencies and re-qualification requirements is essential to ensure that an aggressive approach is taken to fill positions with properly trained personnel.

L.02.b. Verify the qualification of personnel that carry out assessments and who evaluate assessment results. [§192.915(b)]

L.02.b. Supplemental Guidance:

- Personnel who carry out and evaluate assessment information must meet documented qualification requirements. This applies to both operator and vendor personnel.
- The operator is responsible for ensuring that vendor personnel who are properly qualified fulfill essential tasks in performing or evaluating assessment.
- Personnel who are not qualified may participate in the assessment activities, but only under the direct control and supervision of a qualified person as part of on-the-job-training (OJT).

L.02.c. Verify the qualification of personnel who participate in implementing preventive and mitigative measures including: [§192.915(c)]

i. Personnel who mark and locate buried structures.
ii. Personnel who directly supervise excavation work.
iii. Other personnel who participate in implementing preventive and mitigative measures as appropriate. [ASME B31.8S-2004, Section 12.2(b)(4)]

L.02.c. Supplemental Guidance:

- Personnel who implement preventive and mitigative measures include a wide range of job positions. This may include management and technical personnel, risk evaluators, operators, excavation crews, welders, pipeline safety engineers, etc. The focus of the inspector's review in this area should be:
    - What role does this person play in implementing Preventive and Mitigative Measures?
    - What are the qualification requirements as they relate to this role?
    - Does the person in this position meet these requirements?

L.02.d. Verify that the personnel who execute the activities within the integrity management program are competent and properly trained in accordance with the quality control plan. [ASME B31.8S-2004, Section 11(a)(8) and ASME B31.8S-2004, Section 12.2(b)(4)]

L.02.d. Supplemental Guidance:

- Personnel, including vendors and subcontracted personnel, involved in the integrity management program are expected to be competent, aware of the program and all of its activities and are to be properly trained to execute the activities within the program.
- Documentation of such competence, awareness and qualification, and the process for their achievement, is to be a part of the quality control plan.

L.03 Invoking Non-Mandatory Statements in Standards

Verify that non-mandatory requirements (e.g., "should" statements) from industry standards or other documents invoked by Subpart O (e.g., ASME B31.8S-2004 and NACE RP0502-2002) are addressed by one of the following approaches: [§192.7(a)]

L.03 *Supplemental Guidance:*

- Various sections of industry standard documents, most notably ASME B31.8S-2004 and NACE RP0502-2002, are directly invoked by the Gas IM Rule. Notable examples may be found in Rule sections 192.911(k), 192.911(l), and 192.911(m). Numerous statements made in these documents that employ words like "the operator should..." as opposed to more restrictive wording like "the operator shall..." or "the operator must...". 49 CFR 192.7, paragraph (a) specifies that referenced documents in §192 have the full effect of Rule requirements, just as if the words were explicitly cited in the Rule. The application of "shall" statements in referenced standards is therefore straightforward. The "should" statements, on the other hand, often represent best practices that

may or may not apply to the way an operator conducts business. At other times, the "should" statements may represent a recommendation that the operator would be reasonably expected to incorporate in their Integrity Management Program. In either case, since the "should" language is invoked in the rule just as if it were set out in the rule in full, then the rule in effect states that operators SHOULD incorporate these recommendations into their integrity management programs. The intent is that the operator should read and be aware of the recommendations of a standard invoked by the Rule and implement them. If the operator decides not to implement the recommendation, then a documented basis for why the recommendation was not implemented is to be developed. This position is documented in FAQ-244.

- An alternative approach to implementing the recommendation is acceptable, but the operator must be prepared to demonstrate equivalence of, or provide technical justification for, the alternative approach.
- FAQ-155 states that where sections of consensus standards are incorporated by reference into a rule, those sections become binding requirements the same as if the language were repeated in the rule (Re: 192.7). This also means that if the referenced section of the standard contains internal references to other sections of a standard, then those other references are also binding. Again, it is the same as if the language were repeated in the rule. In this case, it is the same as if the internal references were repeated in the rule. For example, B31.8S, Section 5 is invoked in 192.917. Section 5 include references to several other sections including Sections 3, 4, 6, 7, 11, and 12.
- FAQ-167 states that when standards are incorporated into a rule by reference, the requirements of the standard become requirements of the rule. Operators are required to implement "must" and "shall" statements in the standard. Where the standard provides an alternative, e.g., in the event an action that "must" be done cannot be accomplished, the alternative must be implemented with appropriate justification.
- An example of regulatory intent for use of "should" statements or recommendations may be found in the Federal Register Notice for 49 CFR Part 195, dated April 2, 1999 [Docket No. RSPA-97-2095-21; Amendment 195-66] for breakout tanks on hazardous liquid systems. A copy of this notice is located in the Gas IMDB File Library with appropriate sections highlighted (Reference: SHOULD). While this notice predates the Gas IM rule, it demonstrates the regulatory intent with respect to "should" statements, as well as in cases where engineering judgment is used to determine compliance.
- FAQ-114 notes that appendices to Part 192 are guidance and do not contain requirements. Where "must" is used to provide guidance for what an operator must do to comply with a requirement in the body of Subpart O, then that action may be required as a result of the language in the rule body. Compliance with the Appendices is not required solely because of the use of "must" statements.
- "**Should**" requirements from various locations in the referenced standards are highlighted throughout the protocols. After inspecting the previous protocols, inspectors may already have a good indication of the operator's approach to implementing "should" requirements.

L.03.a. Incorporated into the operator's plan and implemented as recommended in the standard; or

L.03.a. Supplemental Guidance:

- When a "should" statement or recommendation in the invoked Standard is directly implemented by the operator, documented program requirements must be available to demonstrate implementation.
- Inspectors should inspect the records generated by the program requirements to confirm implementation.

L.03.b. An equivalent alternative method for accomplishing the same objective is justified and implemented; or

L.03.b. Supplemental Guidance:

- Operators may choose to implement an alternative approach in meeting the recommendations of invoked standards. When the operator has chosen an alternative approach, there should be evidence that the operator recognizes and understands the recommendations in the invoked standard and how the alternative approach fulfills the intent of the recommendation.
- Program requirements for the alternative approach should be confirmed to exist in IM Program documents and records generated by the alternative approach.

L.03.c. A documented justification is included in the plan that demonstrates the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O.

L.03.c. Supplemental Guidance:

- Operators may choose to not implement a recommendation cited in an invoked standard. Inspectors should look for a documented basis for why the recommendation has not been implemented.
- The inspector should be satisfied that the basis is reasonable and that not implementing the recommendation will not compromise pipeline integrity.

Protocol Area M. Communications Plan

- M.01 External and Internal Communication Requirements
- M.02 Addressing Safety Concerns
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M.01 External and Internal Communication Requirements

Verify that an integrity management communication plan exists that meets the requirements of ASME B31.8S-2004, Section 10. [§192.911(m)]

M.01 *Supplemental Guidance:*

- ASME B31.8S-2004, Section 10 mandates the development of communication plan to keep an operator's personnel, jurisdictional authorities, and the public aware of its integrity management efforts and results. Beyond the requirement that a plan be developed with that stated intent, the information in the standard regarding the methods and frequency of the communication plan is only recommended.
- Periodic communication, rather than sporadic communication is recommended and the operator should be able to defend the frequency chosen.
- Communications internal to the operator's organization is aimed at building program support and to inform all participants in the progress and problems of the program.
- FAQ-184 addresses the content/information that is to be communicated with the public/public officials about integrity management plan and activities related to IMP.

M.01.a. Verify that the operator has submitted its API-1162 external communications plan to the PHMSA clearinghouse for approval.

M.01.a. Supplemental Guidance:

- * Operators' external communication programs are being reviewed by PHMSA as a separate activity. Inspector knowledge that the program has been reviewed is satisfactory - detailed inspection of the API RP-1162 program is not expected. The operator should be expected to provide documentation demonstrating submittal of the communications program to PHMSA.

M.01.b. Verify provisions for operator internal organizational communication exist to establish understanding of and support for the integrity management program. [ASME B31.8S-2004, Section 10.3]

M.01.b. Supplemental Guidance:

- Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan.
- Performance measures reviewed on a periodic basis and resulting adjustments to the integrity management program should also be part of the internal communications plan.
- Integrity management program information may be included along with other notifications provided to company personnel.

M.02 Addressing Safety Concerns

Verify that provisions exist to address safety concerns raised by:

M.02 *Supplemental Guidance:*

The operator must implement a process to address safety concerns raised by PHMSA or the Interstate Agent or other local or state pipeline safety authorities. This could be part of an existing corrective action process, however it should demonstrate interface with PHMSA or local/state pipeline safety authorities, as applicable. As with any safety concern, the appropriate response might include remedial corrective measures, a root cause determination, assessment of generic implications, and actions to prevent recurrence. Documentation should be reviewed to confirm that any corrective measures identified were performed as indicated in the response to PHMSA or the local/state safety authority, and on a schedule commensurate with the threat to safety.

M.02.a. PHMSA and State or local pipeline safety authorities (when a covered segment is located in a State where PHMSA has an interstate agent agreement). [§192.911(m)(1) and §192.911(m)(2)].

M.02.a. Supplemental Guidance:

- An interface with the appropriate PHMSA personnel should be proceduralized and conducted as part of the program to address safety concerns. If someone from PHMSA that is not on the inspection team had the safety concern, communication between the inspector and that individual may be necessary to ensure that the safety issues are being properly addressed.
- An interface with the appropriate Interstate Agent (as applicable) or other local/state pipeline inspectors should be proceduralized and implemented as part of the program to address safety concerns. If a local/state inspector that is not on the inspection team had the safety concern, communication between the inspector and that individual may be necessary to ensure that the safety issues are being properly addressed.

Protocol Area N. Submittal of Program Documents

- N.01 Integrity Management Program Document Submittal
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N.01 Integrity Management Program Document Submittal

Verify that the operator includes provisions in its program to submit, upon request, the operator's risk analysis or integrity management program to: [§192.911(n)]

N.01 *Supplemental Guidance:*

- If PHMSA or a pipeline safety authority in the state where PHMSA has an Interstate Agent Agreement requests documents from the operator, these must be provided in a timely manner. There are three acceptable methods of providing this information:
    - e-mail
    - fax
    - regular mail.
- It is not preferred to hand official copies to inspectors during inspections but instead these should be transmitted in a formal manner. This does not preclude or prevent communications during inspections or the exchange of unofficial copies for the purpose of the inspection, but rather is intended to ensure that formal requests are responded to in like manner.
- If an inspector is aware of a formal request that has been made for IM Program or risk analysis documents, it would be reasonable to request the operator demonstrate their compliance with that request. Further, the operator's IM Program or framework documentation should have a requirement that instructs personnel to provide this information to PHMSA or the Interstate Agent when it is requested.

N.01.a. PHMSA and State or local pipeline safety authorities, as applicable. [§192.911(n)]

N.01.a. Supplemental Guidance:

- Contact information for providing documents to PHMSA may be found in §192.951 of the Rule.
- The inspector should be able to locate in the operator's program documentation requirements for submittal of documents to Interstate Agents or other local or state pipeline authorities when applicable.