to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* § 192.7);

(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

[Amdt. 192–132, 87 FR 52276, Aug. 24, 2022]

§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in § 192.937 must have a plan that meets the requirements of this section and of §§ 192.925 (ECDA) and § 192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with § 192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with § 192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, *see* § 192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with § 192.933 until the operator has completed reassessment using one of the assessment techniques allowed in § 192.937.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–114, 75 FR 48604, Aug. 11, 2010; Amdt. 192–119, 80 FR 178, Jan. 5, 2015]

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

(1) *Temporary pressure reduction.* (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other

action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with §192.712. An operator must notify PHMSA in accordance with §192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under §192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with §192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, *see* §192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with §192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with §192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with §192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with §192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraphs (d)(1) and (3) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with §192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with §192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with §192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with §192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with §192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with §192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with §192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe), and for which engineering analyses of the dent, performed in accordance with §192.712(c), demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with §192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with §192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with §192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with §192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with §192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007; Amdt. 192–119, 80 FR 182, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015; Amdt. No. 192–125, 84 FR 52254, Oct. 1, 2019; Amdt. 192–132, 87 FR 52277, Aug. 24, 2022; Amdt. 192–133, 88 FR 24712, Apr. 24, 2023]