§ 195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§ 195.583 What must I do to monitor atmospheric corrosion control?

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by § 195.581.

§ 195.585 What must I do to correct corroded pipe?

(a) *General corrosion.* If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you—

(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) *Localized corrosion pitting.* If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

§ 195.587 What methods are available to determine the strength of corroded pipe?

Under § 195.585, you may use the procedure in ASME/ANSI B31G (incorporated by reference, *see* § 195.3) or in PRCI PR–3–805 (R–STRENG) (incorporated by reference, *see* § 195.3) to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

[Amdt. 195–99, 80 FR 188, Jan. 5, 2015]

§ 195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion or stress corrosion cracking, you must follow the requirements of this section. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) *General.* You must follow the requirements of NACE SP0502 (incorporated by reference, *see* § 195.3). Also, you must develop and implement a External Corrosion Direct Assessment (ECDA) plan that includes procedures

addressing pre-assessment, indirect examination, direct examination, and post-assessment.

(2) *Pre-assessment.* In addition to the requirements in Section 3 of NACE SP0502 (incorporated by reference, *see* § 195.3), the ECDA plan procedures for pre-assessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and

(iii) If you utilize an indirect inspection method not described in Appendix A of NACE SP0502 (incorporated by reference, *see* § 195.3), you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(3) *Indirect examination.* In addition to the requirements in Section 4 of NACE SP0502 (incorporated by reference, *see* § 195.3), the procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:

(A) The known sensitivities of assessment tools;

(B) The procedures for using each tool; and

(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) For each indication identified during the indirect examination, criteria for—

(A) Defining the urgency of excavation and direct examination of the indication; and

(B) Defining the excavation urgency as immediate, scheduled, or monitored; and

(iv) Criteria for scheduling excavations of indications in each urgency level.

(4) *Direct examination.* In addition to the requirements in Section 5 of NACE SP0502 (incorporated by reference, *see* § 195.3), the procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502 (incorporated by reference, *see* § 195.3) provides guidance for criteria); or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502 (incorporated by reference, *see* § 195.3) provides guidance for criteria);

(iii) Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis you will reclassify and reprioritize any of the provisions specified in Section 5.9 of NACE SP0502 (incorporated by reference, *see* § 195.3).

(5) *Post assessment and continuing evaluation.* In addition to the requirements in Section 6 of NACE SP 0502 (incorporated by reference, *see* § 195.3), the procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE SP0502 (*see* appendix D of NACE SP0502) (incorporated by reference, *see* § 195.3).

(c) If you use direct assessment on an onshore pipeline to evaluate the effects of stress corrosion cracking, you must develop and follow a Stress Corrosion Cracking Direct Assessment plan that meets all requirements and recommendations of NACE SP0204–2008 (incorporated by reference, *see* § 195.3) and that implements all four steps of the Stress Corrosion Cracking Direct Assessment process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204–2008, Section 1.1.7, Stress Corrosion Cracking Direct Assessment is complementary with other inspection methods such as in-line inspection or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data to identify whether the conditions for stress corrosion cracking are present and to prioritize the segments for assessment in accordance with NACE SP0204–2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204–2008 indicate the potential for Stress Corrosion Cracking Direct Assessment. This data gathering process must be conducted in accordance with NACE SP0204–2008, Section 5.3, and must include, at a minimum, all data listed in NACE SP0204–2008, Table 2. Further, an operator must analyze the following factors as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, factors that affect the rate of carbon dioxide generation, and/or cathodic protection.

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied cathodic protection such as overprotection, cathodic protection loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield cathodic protection when disbonded from the pipe.

(v) Other factors that affect the mechanistic properties associated with SCC including but not limited to operating pressures, high tensile residual stresses, and the presence of sulfides.

(2) *Indirect inspection.* In addition to the requirements and recommendations of NACE SP0204–2008, Section 4, the plan's procedures for indirect inspection must include provisions for conducting at least two different, but complementary, indirect assessment electrical surveys, and the basis on the selections as the most appropriate for the pipeline segment based on the data gathering and integration step.

(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204–2008, Section 5, the plan's procedures for direct examination must provide for conducting a minimum of four direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Non-significant SCC, as defined by NACE SP0204–2008, may be mitigated by either hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG (incorporated by reference, *see* § 195.3) and must be sufficient to meet the design requirements of subpart C of this part.

(ii) Significant SCC must be mitigated using a hydrostatic testing program with a minimum test pressure between 100% up to 110% of the specified minimum yield strength for a 30-minute spike test immediately followed by a pressure test in accordance with subpart E of this part. The test pressure for the entire sequence must be continuously maintained for at least

8 hours, in accordance with subpart E of this part. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment retested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (c)(4)(i) of this section.

(5) *Post assessment.* In addition to the requirements and recommendations of NACE SP0204–2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of Stress Corrosion Cracking Direct Assessment, the plan's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to Stress Corrosion Cracking as well as on the behavior mechanism of identified cracking. Factors to be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204–2008, sections 5.3.5.7, 5.4, and 5.5;

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

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

(iv) Operating temperature and pressure conditions;

(v) Cyclic loading conditions;

(vi) 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. 195–85, 70 FR 61576, Oct. 25, 2005, as amended by Amdt. 195–94, 75 FR 48607, Aug. 11, 2010; Amdt. 195–101, 82 FR 8000, Jan. 23, 2017]

§ 195.589 What corrosion control information do I have to maintain?

(a) You must maintain current records or maps to show the location of—

(1) Cathodically protected pipelines;

(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and

(3) Neighboring structures bonded to cathodic protection systems.

(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §§ 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

§ 195.591 In-Line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API Std 1163, *Inline Inspection Systems Qualification Standard;* ANSI/ASNT ILI–PQ, *Inline Inspection Personnel Qualification and Certification;* and NACE SP0102–2010, *Inline Inspection of Pipelines* (incorporated by reference, see § 195.3). An in-line inspection may also be conducted using tethered or remote control tools provided they generally comply with those sections of NACE SP0102–2010 that are applicable.

[Amdt. 195–101, 82 FR 8000, Jan. 23, 2017]

APPENDIX A TO PART 195—DELINEATION BETWEEN FEDERAL AND STATE JURISDICTION—STATEMENT OF AGENCY POLICY AND INTERPRETATION

In 1979, Congress enacted comprehensive safety legislation governing the transportation of hazardous liquids by pipeline, the Hazardous Liquids Pipeline Safety Act of 1979, 49 U.S.C. 2001 *et seq.* (HLPSA). The HLPSA expanded the existing statutory authority for safety regulation, which was limited to transportation by common carriers in interstate and foreign commerce, to transportation through facilities used in or affecting interstate or foreign commerce. It also added civil penalty, compliance order, and injunctive enforcement authorities to the existing criminal sanctions. Modeled largely on the Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1671 *et seq.* (NGPSA), the