ATTACHMENT 1 – INGAA'S PROPOSED REGULATORY TEXT

The legend for the redline is as follows: (i) black text represents existing, currently-effective regulations; (ii) red text (whether struck through or not) represents PHMSA's proposed changes as set forth in the NPRM; and (iii) blue text (whether struck through or not) represents INGAA's proposed changes to the PHMSA NPRM proposal.

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§ 192.3 Definitions.

Close interval survey means a ~~series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.~~ potential survey performed on a buried or submerged metallic pipeline, in order to obtain valid DC structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.

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Dry gas or dry natural gas means ~~gas with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream~~ a gas above its dew point and without condensed liquids.

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Electrical survey means ~~a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline on ineffectively coated or bare pipelines.~~ a cell-to-cell surface potential gradient survey consisting of a series of potential gradients measured along the pipeline, often used on pipelines that are not electrically continuous or on bare or ineffectively coated pipelines in order to detect the probable current discharge (anodic) areas along a pipeline. Where the pipeline is electrically continuous, a close-interval survey and lateral potentials will also detect areas of probable current discharge (anodic areas).

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An instrumented inline inspection segment means a length of pipeline through which a free-swimming commercially available in-line inspection tool can travel without the need for any permanent physical modifications to the pipeline and (1) is capable of assessing the identified threat(s); (2) can inspect the entire circumference of the pipe; and (3) can record or transmit relevant, interpretable inspection data.

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Moderate Consequence areas means an onshore area that is within a potential impact circle ~~as defined in § 192.903~~ of an instrumented inline inspection segment, located outside of a HCA, Class 3 and 4 area containing:

i. five (5) or more buildings intended for human occupancy;
ii. ~~an occupied site~~ a non-residential building that is occupied by five (5) to nineteen (19) persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.); or
iii. ~~a right-of-way~~ the edge of pavement ~~for~~ of a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures*~~, and does not meet the definition of high consequence area as defined in § 192.903.~~

The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either ~~an occupied site,~~ five (5) or more buildings intended for human occupancy, or the edge of pavement ~~for~~ of a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway, to the outermost edge of the last contiguous potential impact circle that contains either ~~an occupied site,~~ five (5) or more buildings intended for human occupancy, or the edge of pavement ~~a right-of-way for~~ of a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway.

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~~*Occupied site* means each of the following areas:~~

~~(1) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or~~

~~(2) A building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks.~~

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Traceable, verifiable, and complete means that a single record or a combination of records: (1) can be linked to original information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or (2) has other similar characteristics that support its validity. A single record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

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§ 192.5 Class locations.

[…]

(d) For transmission pipelines, each operator must retain ~~R~~records for the life of the pipeline that are created after *[the effective date of the Final Rule]* ~~transmission pipelines documenting class locations~~ and demonstrate~~ing~~ how an operator determined a class location~~s~~ ~~in accordance with this section must be retained for the life of the pipeline~~.

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§ 192.13 What general requirements apply to pipelines regulated under this part?

[…]

(d) Within [five (5) years from effective date of the Final Rule] ~~E~~each operator of an onshore gas transmission pipeline must ~~evaluate and mitigate, as necessary, risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline~~ develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical design, physical, ~~environmental~~, procedural, ~~operational, maintenance~~, and organizational changes to the pipeline or processes, whether permanent or temporary. Depending on the nature of the change, ~~A~~a management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them.

~~(e) Each operator must make and retain records that demonstrate compliance with this part.~~
~~(1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192.~~
~~(2) Records must be reliable, traceable, verifiable, and complete.~~

~~(3) For pipeline material manufactured before *[effective date of the final rule]* and for which records are not available, each operator must re-establish pipeline material documentation in accordance with the requirements of § 192.607.~~

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§ 192.67-Records: Materials

For transmission pipe manufactured after *[effective date of the final rule]*, ~~E~~each operator ~~of transmission pipelines~~ must ~~acquire and~~ retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured~~, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with § 192.55~~.

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§ 192.127 Records: Pipe design

For transmission pipe manufactured after *[effective date of the final rule]*, ~~E~~each operator ~~of transmission pipelines~~ must ~~make and~~ retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105.

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§ 192.205-Records: Pipeline components

For valves manufactured after *[effective date of the final rule]* and used in connection with transmission pipelines, ~~E~~each operator ~~of transmission pipelines~~ must ~~acquire and~~ retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi or greater, manufactured after *[effective date of the final rule]*, must have records documenting the manufacturing specification in effect at the time of manufacture ~~including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials.~~

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Appendix A to Part 192-Records Retention Schedule for Transmission Pipelines

Appendix A summarizes the part 192 records retention requirements. These retention requirements apply to records created after *[the effective date of the Final Rule.]* ~~As required by § 192.13(e), records must be readily retrievable and must be reliable, traceable, verifiable, and complete.~~

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§ 192.319 Installation of pipe in a ditch.

[…]

(d) Promptly after a ditch for a steel onshore transmission line is backfilled**,** but not later than ~~three months~~ one year after placing the ~~pipeline~~ cathodic protection system in service, the operator must perform an indirect assessment (using an indirect method, such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) ~~to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.~~ Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the ~~coating~~ indirect assessment findings and ~~repairs~~ remedial actions.

§ 192.461 External corrosion control: Protective coating.

[…]

(f) Promptly, but no later than ~~three months~~ one year after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct an indirect assessment (using an indirect method, such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) ~~surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.~~

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§ 192.465 External corrosion control: Monitoring and remediation

[…]

(d) Each operator ~~shall take~~ must promptly ~~remedial action to~~ correct any deficiencies indicated by the ~~monitoring.~~ inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less~~.~~, or as soon as practicable after obtaining necessary permits.

[…]

(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d) of this section. The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area. Close interval surveys are not required in instances where low potentials are measured for electrical short to an adjacent foreign structure, rectifier connection or power sources. The operator may presume that the preponderance of pipe between test stations does not meet the required cathodic protection levels. Operators can perform a close interval survey following the remedial measures to confirm restoration of adequate cathodic protection.

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§ 192.473 External corrosion control: Interference currents.

[…]

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be ~~taken~~ conducted on a

periodic basis ~~including,~~ when potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced, such as ~~there are current flow increases over pipeline segment grounding design, from any~~ co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could ~~impact the effectiveness of cathodic protection~~ cause significant corrosion; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than ~~six months~~ one year after completion of the survey, or as soon as practicable after obtaining necessary permits.

(4) When pipelines are co-located within 1,000 feet of a high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within one year after completing the survey to protect the pipeline segment from interference currents. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. The following criteria shall be used to determine when remedial actions are required.

- *AC-induced corrosion does not occur at AC densities less than 20 A/m^2 (1.9 A/ft^2). The operator shall monitor these locations per (1) (i) above.*
- *AC corrosion is unpredictable for AC densities between 20 to 100 A/m^2 (1.9 to 9.3 A/ft^2). These locations require an engineering assessment to determine if remediation is required.*
- *AC corrosion occurs at current densities greater than 100 A/m^2 (9.3 A/ft^2).” These areas require mitigation.*

Any location that is determined to require mitigation must be mitigated to reduce the AC current density to less than 20 A/m^2

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§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For non-dry gas onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and ~~free~~ liquid water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent (where applicable) by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

~~(b) The monitoring and mitigation program in paragraph (a) of this section should consider methods such as:~~

~~(1) Gas quality monitoring at points where gas with potentially corrosive contaminants enters the pipeline, to determine the gas stream constituents;~~

~~(2) Options such as product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents where corrosive gas is being transported;~~

~~(3) Evaluation each calendar year, at intervals not to exceed 15 months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated where corrosive gas is being transported.~~

~~(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.~~

~~(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7 ½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.~~

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§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking ~~integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment~~ must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

(c) The baseline test pressure without the additional spike test pressure is the test pressure specified in §§ 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.

(d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505(e).

(e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of ~~the lesser of 1.50 times MAOP or~~ ~~105%~~ 100% SMYS. This spike hydrostatic pressure test must be held for at least 30 minutes. After the 30-minute spike interval, the operator may either hold the baseline pressure for the remainder of the 8 hour test interval or, alternatively, an operator can conclude the hydrostatic pressure test after the spike interval and conduct an instrumented leak survey after the pipeline is placed back into service.

(f) ~~If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, t~~The operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.624(d).

(g) *Alternative technology or alternative technical evaluation process.* Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. ~~If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least 180 days in advance of use in accordance with § 192.624(e). The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process. The notification must include the following details:~~

> ~~(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;~~
>
> ~~(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;~~
>
> ~~(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;~~

~~(4) Assessment techniques and acceptance criteria;~~

~~(5) Remediation methods for assessment findings;~~

~~(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;~~

~~(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and~~

~~(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics.~~

***

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines.

(a) ***Applicable locations.*** Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before ***[insert the effective date of the rule]*** that does not have ~~reliable,~~ traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

(1) The pipeline is located in a High Consequence Area as defined in § 192.903*;* or

(2) The pipeline is located in a class 3 or class 4 location

(b) ***Material documentation plan.*** Each operator must prepare a material documentation plan to implement all actions required by this section by ***[date ~~180 days~~ one year after the effective date of the final rule].***

(c) ***Material documentation.*** Each operator must have ~~reliable,~~ traceable, verifiable, and complete records documenting the following:

(1) For line pipe and fittings, records must document diameter, wall thickness, grade ~~(yield strength and ultimate tensile strength), chemical composition,~~ and seam type, ~~coating type, and manufacturing specification.~~

(2) For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. ~~For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;~~

(3) For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure

rating~~, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions~~;

(4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility;

(d) ***Verification of material properties***. For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are required to conduct work under Subparts I, K, L, M, and O and are not available, the operator must take the following actions to determine and verify the physical characteristics.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.

(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, or ~~any other reason for which the pipe segment is exposed~~, except for segments exposed during excavation activities that are in compliance with § 192.614~~, until completion of the minimum number of excavations as follows.~~

~~(i) The operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).~~

~~(ii) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile population would require 15 excavations for each 20 miles. For each population defined according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of the following:~~

~~(A) 150 excavations; or~~

~~(B) If the segment is less than 150 miles, a number of excavations equal to the population's pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.~~

(i~~ii~~). At each excavation, where pipe is removed tests for material properties must determine diameter, wall thickness, yield strength, ~~ultimate tensile strength, Charpy v-notch toughness (where required for failure pressure and crack growth analysis), chemical properties,~~ seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques. Determination of material property values must conservatively account for measurement inaccuracy and uncertainty based upon comparison with destructive test results using unity charts.

~~(iv) If non-destructive tests are performed to determine strength or chemical composition, the operator must use methods, tools, procedures, and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium percentage for the grade of steel being tested.~~

(~~v~~) ~~The minimum number of test locations at each excavation or above-ground location is based on the number of joints of line pipe exposed, as follows:~~

~~(A) 10 joints or less: one set of tests for each joint.~~

~~(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.~~

~~(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.~~

(~~v~~ii) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with operator or service provider specifications ~~at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.~~

(~~v~~iii) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with the original manufacturing specification, if known, such as API Spec 5L ~~on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location~~.

~~(viii) If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that material properties are consistent with all available information for each population, then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing expectations based on all available information for each population, then the operator must perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the table below:~~

~~Number of Excavations With Inconsistency Between Test Results and Existing Expectations Based on All Available Information for each Population~~	~~Minimum Number of Total Required Excavations for Population.~~ ~~The lesser of:~~
~~0~~	~~150 (or pipeline mileage)~~
~~1~~	~~225 (or pipeline mileage times 1.5)~~
~~2~~	~~300 (or pipeline mileage times 2)~~
~~>2~~	~~350 (or pipeline mileage times 2.3)~~

~~(ix) The tests conducted for a single excavation according to the requirements of § 192.607(d)(3)(iii) through (vii) above count as one sample under the sampling requirements of § 192.607(d)(3)(i), (ii), and (viii).~~

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting the ANSI rating, where applicable, and material grade (to assure compatibility with pipe ends).

(i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) Larger than 2-inch nominal diameter ~~and larger~~, or

(B) Material grades greater than 42,000 psi (X-42), or

(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.

~~(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use "other technology" or "new technology" (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.~~

***

§ 192.613 Continuing surveillance.

[…]

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that the operator determines to have the likelihood of significant damage to pipeline facilities ~~infrastructure~~, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

[…]

(2) Time period. The inspection required under the introductory text of paragraph (c) of this section must commence as soon as practicable ~~within 72 hours~~ after the cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment, ~~including~~ taking into account the availability of personnel and equipment required to perform the inspection as determined under paragraph (c)(1) of this section~~, whichever is sooner~~.

***

§ 192.619-Maximum allowable operating pressure: ~~Steel or plastic pipelines~~

[…]

(f) Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that establish the pipeline MAOP, include, but are not limited to design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. Records must be ~~reliable,~~ traceable, verifiable, and complete.

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§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

(a) ***Applicable locations.*** The operator of a pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

[…]

(c) ***Maximum allowable operating pressure determination.*** The operator of a pipeline segment meeting the criteria in paragraph (a) above must establish its maximum allowable operating pressure under one of the following methods.

[…]

(3) *Method 3: Engineering critical assessment* - Conduct an engineering critical assessment and analysis (ECA) to establish the material strength ~~condition~~ of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), and operating history. ~~operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess:~~

~~threats; loadings and operational circumstances relevant to those threats including along the right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.~~

(i) *ECA analysis*.

(A) The ECA must integrate and analyze the results of the material documentation ~~program~~ plan required by §192.607, if applicable.~~, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O.~~

(B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of ~~each defect~~ actionable anomalies. The ECA must use the techniques and procedures in ~~Battelle Final Reports ("Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications" - Task 1.4)~~, Report No. 13-002 ("Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" – Subtask 2.4), Report No. 13-021 ("Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue" – Subtask 2.5) ~~and ("Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures – Phase 1" – Task 4.5)~~ (incorporated by reference, *see* § 192.7) or other technically proven methods including but not limited to API RP 579-1/ASME FFS-1, June 5, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, BMT Fleet Technologies, Fatigue Considerations for Natural Gas Transmission Pipelines, Reference 30348.DFR, June, 2016 or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling). ~~If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then~~ T~~t~~he operator ~~must~~ can determine a representative Charpy v-notch toughness based upon their material documentation ~~program~~ plan ~~specified in~~ developed to comply with the requirements of § 192.607.~~ or use~~ The operator can use toughness data where available based on data it possesses or available through commercial data bases. When operators lack either toughness data or data from publically available databases, they may use conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to ~~5.0~~ 13 ft-lb and seam toughness of less than or equal to ~~1~~ 4 ft-lb.

(C) The ECA must analyze any metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. ~~If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607.~~

(D) The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

~~(E) The maximum allowable operating pressure must be established at the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).~~

(ii) *Use of prior pressure test.* If pressure test records as described in subpart J and § 192.624(c)(1) exist for the segment, then an in-line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time-dependent threats must be determined in accordance with the methodology in

§ 192.624(d) *Fracture mechanics modeling for failure stress and crack growth analysis.*

(iii) *In-line inspection*. If the segment does not have records for a pressure test in accordance with subpart J test levels and § 192.624(c)(1), the operator must develop and implement an inline inspection (ILI) program using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking. At a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT), circumferential MFL (CMFL) or ultrasonic testing (UT) tool, or a combination of these tools~~.~~

~~(A)~~ In lieu of the tools specified in paragraph § 192.624(c)(3)(i), an operator may use "other technology" if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. ~~If an operator elects to use "other technology," it must notify the Associate Administrator of Pipeline Safety, at least 180 days prior to use, in accordance with paragraph (e) of this section and receive a "no objection letter" from the Associate Administrator of Pipeline Safety prior to its usage. The "other technology" notification must have:~~

~~*(1)* Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and~~

~~*(2)* Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.~~

~~(B) If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.~~

~~(C) If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.~~

(D) Inline inspection must be performed in accordance with § 192.493.

(E) The operator must use unity plots or equivalent methodologies to demonstrate the effectiveness of the ILI tools in identifying and sizing actionable manufacturing and construction-related anomalies. The operator must have a process for identifying outliers and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data or both. ~~All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.~~

~~(F) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and or subpart O, as applicable, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the type defects and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.~~

(G) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria in §§ 192.713 and 192.933.

(iv) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

[…]

(6) *Method 6: Alternative technology* - Operators may use an alternative technology ~~technical evaluation~~ process that provides a sound engineering basis for establishing maximum allowable operating pressure. When using alternative technology, the operator must demonstrate that the technology is capable of achieving the performance of a pressure test in Method 1~~. If an operator elects to~~

~~use alternative technology, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph (e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology …~~

***

§ 192.710 Pipeline assessments.

[…]

(c) Assessment method.

[…]

(4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI) to collect data, as applicable…

[…]

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the Direct Assessment in accordance with the requirements specified in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, or 192.929. The same restriction applies to SCCDA only if stress corrosion cracking has been found on like- pipe in that pipeline segment; or…

***

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

~~(a) *This section applies to transmission lines.* Line segments that are located in high consequence areas, as defined in § 192.903, must also comply with applicable actions specified by the integrity management requirements in subpart O of this part.~~

(a~~b~~) *General.* Each transmission line operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(b~~e~~) *Repair*. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

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

(3) Remediated by an acceptable method as defined in ASME B31.8S, Section 7, Table 4.

~~(b) Operating pressure must be at a safe level during repair operations.~~

(c~~d) Remediation~~ *Response schedule*. For pipelines not located in high consequence areas, an operator must complete the ~~remediation~~ evaluation of a condition determined from in-line inspection and must schedule in-field examination according to the response schedules in section (c)(1), (c)(3) and (c)(4) ~~following schedule:~~. Upon completion of in-field examination and evaluation of the conditions, repairs shall be completed based on the criteria and schedule in sections (e) and (f). An operator must complete response to a condition according to a schedule prioritizing the conditions for evaluation and response. Unless a special requirement for responding to 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.

(1) *Immediate ~~repair~~ response conditions*. An operator must ~~repair the following~~ complete the in-field examination and evaluation of the following conditions immediately upon discovery:

(i) For metal loss or crack or crack-like anomalies, ~~A~~a calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation~~.~~ for metal loss, or Modified Ln Sec 2009 or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME B31.8S. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels. ~~These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material~~

~~properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(ii) A dent~~ that has any indication of metal loss, cracking or a stress riser.~~ located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(iii) Metal loss or cracking greater than 80% of nominal wall regardless of dimensions.

(iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding.

~~(v) Any indication of significant stress corrosion cracking (SCC).~~

~~(vi) Any indication of significant selective seam weld corrosion (SSWC).~~

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

(2) Until the examination and evaluation ~~remediation~~ of a response condition specified in paragraph (~~d~~c)(1) is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location (as provided in §192.111, §192.611(a)(3), §192.619 and §192.620) in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects, or Modified Ln Sec 2009 or equivalent for crack-like defects. ~~Both~~These procedures apply to ~~corroded regions~~ anomalies that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. ~~If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607,~~ or

(ii) 80% of pressure at the time of discovery, if a safe pressure cannot be calculated using one of the above methods~~, whichever is lower~~.

(3) *Two-year response conditions*. An operator must ~~repair~~ complete in-field examination and evaluation the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld.

(iii) For metal loss or crack or crack-like anomalies, anomalies must be investigated if ~~A~~a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. ~~This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment~~. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009 or equivalent for crack-like defects. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels.

~~(iv) An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(~~v~~iv) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

~~(v) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

~~(vi) A gouge or groove greater than 12.5% of nominal wall.~~

~~(vii) Any indication of crack or crack-like defect other than an immediate condition.~~

(4) *Monitored conditions*. An operator does not have to schedule the following conditions for ~~remediation~~ in-field examination and evaluation, but must record

and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth weld or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(iv) A dent that has any indication of metal loss, cracking or a stress riser and an engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non injurious and does not pose a public safety threat.

(d~~e~~) *Repair Conditions*. An operator must immediately repair the following verified conditions on the pipeline:

(1) Corrosion metal loss or cracking with a remaining strength of the pipe below a predicted failure pressure less than or equal to the failure pressure with the required design factor applied per §§ 192.111, 192.611(a)(3), 192.619, and 192.620. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009, or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME/ANSI B31.8S.

(2) Corrosion metal loss or cracking in excess of 80% depth.

(3) Dents with a depth greater 6% of nominal pipe diameter, unless the dent strain is less than 6%.

(4) Dents with a depth greater 2% affecting a girth weld or seam weld, unless determined to be safe from an engineering analysis.

(5) Dents that contain corrosion in excess of what is allowed by ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation.

(6) Dents that contain stress corrosion cracking or other cracks.

(7) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion) whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.

(8) Any significant selective seam weld corrosion.

(e) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects.* Whenever required by this part, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch 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 and in metallurgy and fracture mechanics for accuracy for 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.

***

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

[…]

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, ~~verify,~~ validate, and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section. ~~and Appendix A to ASME/ANSI B31.8S.~~ ~~and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.~~ Where data is missing, conservative assumptions shall be used when performing the risk assessment. An operator may collect any newly identified data consistent with the timelines set forth in § 192.624(b). The evaluation must analyze ~~both~~ the covered segment and consider similar non-covered segments as follows: ~~, and must:~~

(1) Integrate information about pipeline attributes and other relevant information, including, but not limited to.

(i) Pipe diameter, wall thickness, grade, seam type and joint factor;

(ii)Manufacturer and manufacturing date, including manufacturing data and records;

~~(iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition;~~

~~(iv) Equipment properties;~~

(~~v~~iii) Year of installation;

(~~vi~~iv) Bending method;

(~~vii~~v) Joining method~~, including process and inspection results~~;

(~~viii~~vi) Depth of cover surveys including ~~stream and~~ river crossings and navigable waterways~~, and beach approaches~~;

(~~ix~~vii) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(~~x~~viii) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(~~xi~~ix) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;

(~~xii~~x) Soil~~, backfill~~;

(~~xiii~~xi) Construction inspection reports, including but not limited to:

~~(A) Girth weld non-destructive examinations;~~

~~(B)~~ Post backfill coating surveys;

~~(C) Coating inspection ("jeeping") reports;~~

(~~xiv~~xii) Cathodic protection installed, including but not limited to type and location;

~~(xv) Coating type;~~

(~~xvi~~xiii) Gas quality;

(~~xvii~~xiv) Flow rate;

(~~xviii~~xv) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(~~xix~~xvi) Class location;

(~~xx~~xvii) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(~~xxi~~xviii) Coating condition;

~~(xxii) CP system performance;~~

(~~xxiii~~xix) Pipe wall temperature;

(~~xxiv~~xx) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

(E) AC/DC and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(~~xxv~~xxi) Outer Diameter/Inner Diameter corrosion monitoring;

(~~xxvi~~xxii) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(~~xxvii~~xxiii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(~~xxviii~~xxiv) ~~Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline~~ One call data - Encroachments to the pipeline and ROW;

(~~xxix~~xxv) Repairs;

(~~xxx~~xxvi) Vandalism;

(~~xxxi~~xxvii) External forces;

(~~xxxii~~xxviii) Audits and reviews;

(~~xxxiii~~xxix) Industry experience for incident, leak and failure history;

(~~xxxiv~~xxx) Aerial photography;

(~~xxxv~~xxxi) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

~~(xxxvi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.~~

(2) Use objective~~, traceable, verified,~~ and validated information and data as inputs, where the operator is missing data, conservative assumptions shall be used when performing risk assessment as noted in B31.8S Appendix A. ~~to the maximum extent practicable.~~ If input is obtained from subject matter experts (SMEs), the operator must employ adequate control measures to ensure consistency and accuracy of information~~. measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.~~

~~(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient;~~ and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that analyzes ~~follows ASME/ANSI B31.8S, section 5, and considers~~ the identified threats and potential consequences of an incident for each covered segment. ~~The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated~~ An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to ~~prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.~~ determine additional preventive and mitigative measures needed (§ 192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas~~, including the consequences of the entire worst-case incident scenario from initial failure to incident termination~~;

(2) Analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in ~~the model and~~ the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities ~~such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals~~.

[…]

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

[…]

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the

covered segment. ~~An~~The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. ~~Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks.~~ Cyclic fatigue analysis must be ~~annually, not to exceed 15 months~~ conducted periodically, not to exceed seven (7) calendar years.

(3) *Manufacturing and construction defects.* ~~If an operator identifies the threat of~~ An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment according to the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A5.3. ~~an operator must analyze the covered segment to determine the risk of failure from these defects.~~ The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of this part of at least 1.25 times MAOP, and the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test. ~~operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area.~~ If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment~~, and must reconfirm or reestablish MAOP in accordance with §192.624(c)~~.

(i) ~~Operating pressure increases above the maximum operating pressure experienced during the preceding five years;~~ The segment has experienced an in-service incident as described in §192.624(a)(1).

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including but not limited to ~~pipe body cracking,~~ seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years ~~(including~~

~~abnormal operation as defined in §192.605(c))~~, or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. ~~Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.624(c) and (d).~~

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§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of line pipe in each covered segment by applying one or more of the following methods ~~depending on the~~ for each threat~~s~~ to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. ~~An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment~~. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ An operator must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

[…]

(3) "Spike" hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking~~, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects~~;

[…]

(6~~3~~) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with~~, as~~ the applicable, the requirements specified in §§ 192.925, 192.927 or 192.929; or

***

§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.

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7)~~;~~ or AGA Pipeline Research Council~~,~~ International, PR-3-805 (R-STRENG) (incorporated by reference, *see* § 192.7) for corrosion defects, or Modified Ln Sec 2009 or equivalent for crack-like defects to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location (as provided in § 192.111, § 192.611(a)(3), § 192.619, and § 192.620) in which the affected pipeline is located~~;~~ or reduce ~~by reducing~~ the operating pressure to a level not exceeding 80 percent of the ~~level~~ operating pressure at the time the condition was discovered. ~~Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties~~

~~determined and documented in accordance with § 192.607.~~ An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or ~~through an~~other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement~~,~~ or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

[…]

(c) *Schedule for evaluation and ~~remediation~~response.* An operator must complete ~~remediation of~~ response to a condition according to a schedule prioritizing the conditions for evaluation and ~~remediation~~response. Unless a special requirement for ~~remediating~~ responding to 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~~*response—

(1) *Immediate ~~repair~~ response conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate ~~repair~~response 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~~response conditions:

(i) For metal loss or crack or crack-like anomalies, a ~~A c~~Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable remaining strength calculation methods include~~,~~ ASME/ANSI B31G (incorporated by reference, *see* § 192.7), PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* § 192.7);~~,~~ or an alternative equivalent method of remaining strength calculation for metal loss, or Modified Ln Sec 2009 or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME B31.8S. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels. ~~that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(ii) ~~A dent that has any indication of metal loss, cracking or a stress riser.~~ A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

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

(iv) Metal loss or cracking greater than 80% of nominal wall regardless of dimensions.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency~~, or high frequency~~ electric resistance welding or by electric flash welding.

~~(vi) Any indication of significant stress corrosion cracking (SCC).~~

~~(vii) Any indication of significant selective seam weld corrosion (SSWC).~~

(2) *One-year response conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must ~~remediate~~ complete in-field examination and evaluation of any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(iii) For metal loss or crack or crack-like anomalies, anomalies must be investigated if a ~~A~~ calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009 or equivalent for crack like defects. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels.

(iv) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

~~(iv) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.~~

~~(v) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

~~(vi) A gouge or groove greater than 12.5% of nominal wall.~~

~~(vii) Any indication of crack or crack-like defect other than an immediate condition.~~

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for ~~remediation~~ in-field examination and evaluation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(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% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(iv) A dent that has any indication of metal loss, cracking or a stress riser and an engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non injurious and does not pose a public safety threat.

(~~e~~) *Repair*. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

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

(3) Remediated by an acceptable method as defined in ASME/ANSI B31.8S, Section 7, Table 4.

(f) *Repair Conditions*. An operator must immediately repair the following verified conditions on the pipeline:

(1) Corrosion metal loss or cracking with a remaining strength of the pipe below a predicted failure pressure less than or equal to the failure pressure with the required design factor applied per § 192.111, § 192.611(a)(3), § 192.619 and § 192.620. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009, or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME/ANSI B31.8S.

(2) Corrosion metal loss or cracking in excess of 80% depth.

(3) Dents with a depth greater 6% of nominal pipe diameter, unless the dent strain is less than 6%.

(4) Dents with a depth greater 2% affecting a girth weld or seam weld, unless determined to be safe from an engineering analysis.

(5) Dents that contain corrosion in excess of what is allowed by ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation.

(6) Dents that contain stress corrosion cracking or other cracks.

(7) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion) whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.

(8) Any significant selective seam weld corrosion.

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§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. ~~An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to,~~ Such additional measures must be based on the risk analyses required by § 192.917, and ~~must~~ may include, but are not limited to:

[…]

(f) *Internal corrosion*. For segments with an identified internal corrosion threat, ~~As~~ an operator ~~gains information about internal corrosion, it~~ must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators ~~must~~ should, based on a risk analysis for the pipeline segment, consider implementing any of the following ~~must—~~

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators ~~and~~ or continuous gas quality monitoring equipment, or take other appropriate steps to mitigate the risk associated with deleterious contaminants.

(3) At least once per quarter, use gas quality monitoring equipment that may include~~s~~, ~~but is not limited to,~~ a moisture analyzer, chromatograph, carbon dioxide sampling, ~~and~~ or hydrogen sulfide sampling.

(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(5) Use inhibitors when corrosive gas or corrosive liquids are present.

~~(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:~~

~~(i) Limit carbon dioxide to three percent by volume;~~

~~(ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and~~

~~(iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.~~

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents

(g) *External corrosion*. As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when a pipelines is co-located within 1,000 feet of a ~~new or uprated~~ high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within ~~six months~~ one year after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. ~~Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.~~

The following criteria shall be used to determine when remedial actions are required.

- *AC-induced corrosion does not occur at AC densities less than 20 A/m^2 (1.9 A/ft^2). The operator shall monitor these locations per (1) (i) above.*
- *AC corrosion is unpredictable for AC densities between 20 to 100 A/m^2 (1.9 to 9.3 A/ft^2). These locations require an engineering assessment to determine if remediation is required.*
- *AC corrosion occurs at current densities greater than 100 A/m^2 (9.3 A/ft^2)." These areas require mitigation.*

Any location that is determined to require mitigation must be mitigated to reduce the AC current density to less than 20 A/m^2

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection system by conducting an indirect inspection through an indirect method such as close-interval survey~~, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG)~~. Alternatively, an operator may validate the effectiveness of the cathodic protection system by demonstrating that corrosion growth is not occurring on the pipeline. This may be accomplished with methods such as ILI run-to-run comparisons or ECDA.

(ii) Remediate any ~~damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502-2008 (incorporated by reference, see § 192.7)~~ cathodic protection levels below the required levels in Appendix D of this part according to § 192.564(d).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than ~~6 months~~ one year after assessment finding.

(iv) Perform periodic assessments as follows:

(A) Conduct periodic close interval surveys ~~with current interrupted~~ to confirm compliance with Appendix D criteria to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

(B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

(C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

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§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

[…]

(c) *Assessment methods*. ~~In conducting the integrity reassessment, a~~An operator must assess the integrity of the line in ~~the~~each covered segment by applying one or more~~any~~ of the following methods for each threat ~~as appropriate for the threats~~ to which the covered segment is susceptible. ~~(*See* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.~~ The operator must select the method or method best suited to address the threats identified to the covered segment (*See* § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

[…]

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section. The same restriction applies to SCCDA only if stress corrosion cracking has been found on like- pipe in that pipeline segment

Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

I. *Criteria for cathodic protection—*

A. *Steel, cast iron, and ductile iron structures.*

Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169:

(1) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made ~~with the protective current applied, and~~ in accordance with sections II and IV of this appendix.

~~(2)~~ A minimum negative (cathodic) polarization voltage shift of at least ~~300~~ 100 millivolts. This polarization voltage shift ~~must~~ should be determined ~~Determination of this voltage shift must be made with the protective current applied, and~~ in accordance with sections II and IV of this appendix. ~~This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.~~

~~(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.~~

~~(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.~~

~~(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.~~

B. *Aluminum structures.*

(1) Except as provided in paragraphs (2) and (3) ~~and (4)~~ of this paragraph, a minimum negative (cathodic) polarization voltage shift of ~~150~~ 100 millivolts~~, produced by the application of protective current. The~~ This polarization voltage shift must be determined in accordance with sections ~~II and IV~~ III and IV of this appendix.

~~(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.~~

(2) Notwithstanding the alternative minimum criteria in paragraph~~s~~ (1) ~~and (2) of this paragraph~~, if aluminum~~, if~~ is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode ~~half cell,~~ in accordance with section ~~IV~~II of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface ~~and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface.~~ A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(3) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at

the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (2) and (3) ~~and (4)~~ of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure-electrolyte boundary. ~~must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.~~ All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

III. *Determination of polarization voltage shift.* The polarization voltage shift ~~must~~ can be determined by methods identified in NACE SP0207-2007, Section 5, such as interrupting the protective current and measuring the polarization decay. On systems where the current can be interrupted, ~~W~~when the current is initially interrupted, an immediate voltage shift occurs which is often referred to as IR drop ~~an instant off potential~~. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

IV. *Reference electrodes (half cells).*

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode ~~half cell~~ contacting the electrolyte.

B. Other standard reference ~~half cells~~ electrodes may be substituted for the saturated cooper-copper sulfate ~~half cell~~ electrode. Two commonly used reference ~~half cells~~ electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate ~~half cell~~ reference electrode:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride ~~half cell~~ reference electrode used in sea water: −0.80 volt.

(c) In addition to the standard reference electrodes ~~half cells~~, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate ~~half cell~~ reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate ~~half cell~~ reference electrode is established.