§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.

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase or transport it for consumption as opposed to customers who purchase it for resale, for example:

1. At a metering location;
2. At a pressure reduction location; or
3. At a location where there is a reduction in the volume of gas, such as a lateral off of a transmission line.

~~a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line.~~

Dry gas or dry natural gas means gas with less than 7 pounds of water per million (MM) cubic feet and not containing excessive amounts of other electrolytes. ~~subject to excessive upsets allowing electrolytes into the gas stream.~~

Electrical survey means a series of closely spaced measurements of the potential difference between two reference electrodes to determine ~~pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations~~ where ~~a corrosive~~ current is leaving the pipe~~line~~ ~~on ineffectively coated or bare pipelines~~.

Gas processing plant means a natural gas processing operation, other than production processing, operated for the purpose of extracting entrained natural gas liquids and other associated non-entrained liquids from the gas stream and does not include a natural gas processing plant located on a transmission line, commonly referred to as a straddle plant.

Gas treatment facility means one or a series of gas treatment operations, operated for the purpose of removing impurities (e.g., water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.) that is not associated with a processing plant or compressor station and is not on a transmission line.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gathering line (Onshore) means a pipeline, or a connected series of pipelines, and equipment used to collect gas from the endpoint of a production facility/operation and transport it to the furthermost point downstream of the following endpoints:

(1) The inlet of 1st gas processing plant, unless the operator ~~submits a request for approval to the Associate Administrator of Pipeline Safety that~~ demonstrates, using sound engineering principles, that gathering extends to a further downstream plant other than a plant located on a transmission line ~~and the Associate Administrator of Pipeline Safety approves such request~~;

(2) The outlet of gas treatment facility that is not associated with a processing plant or compressor station;

(3) Outlet of the furthermost downstream compressor used to facilitate delivery into a pipeline, other than another gathering line; or

(4) The point where separate production fields are commingled, provided the distance between the interconnection of the fields does not exceed 50 miles, unless the operator demonstrates that ~~Associate Administrator of Pipeline Safety finds~~ a longer separation distance is justified in a particular case ~~(see § 190.9)~~.

Gathering may continue beyond the above endpoints to the point gas is delivered into another pipeline, provided that it only does the following:

(i) It delivers gas into another gathering line;

(A) It does not leave the operator's facility surface property (owned or leased, not necessarily the fence line);

(B) It does not leave an adjacent property owned or leased by another pipeline operator's property—where custody transfer takes place; or

(C) It does not extend beyond the connection to the nearest existing transmission pipeline ~~exceed a length of mile, and it does not cross a state or federal highway or an active railroad~~; or

(ii) It transports gas to production or gathering facilities for use as fuel, gas lift, or gas injection gas.

Pipelines that serve residential, commercial, or industrial customers that originate at a tap on gathering lines are not gathering lines; they are service lines and are commonly referred to as farm taps.

Hard spot means steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinnel 327 HB or Vickers 345 HV10).

In-line inspection (ILI) means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called *intelligent* or *smart pigging*.

In-line inspection tool or *instrumented internal inspection device* means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside, which is also called an *intelligent* or *smart pig*.

~~*Legacy construction techniques* mean usage of any historic, now-abandoned, construction practice to construct or repair pipe segments, including any of the following techniques:~~

~~(1) Wrinkle bends;~~

~~(2) Miter joints exceeding three degrees;~~

~~(3) Dresser couplings;~~

~~(4) Non-standard fittings or field fabricated fittings (e.g., orange-peeled reducers) with unknown pressure ratings;~~

~~(5) Acetylene welds;~~

~~(6) Bell and spigots; or~~

~~(7) Puddle welds.~~

~~*Legacy pipe* means steel pipe manufactured using any of the following techniques, regardless of the date of manufacture:~~

~~(1) Low-Frequency Electric Resistance Welded (LF-ERW);~~

~~(2) Direct-Current Electric Resistance Welded (DC-ERW);~~

~~(3) Single Submerged Arc Welded (SSAW);~~
~~(4) Electric Flash Welded (EFW);~~
~~(5) Wrought iron;~~
~~(6) Pipe made from Bessemer steel; or~~
~~(7) Any pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0 (such as lap-welded pipe) or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specification.~~

Moderate consequence area means an onshore area that is within a potential impact circle, as defined in § 192.903, related to a transmission pipeline operating at greater than 30% SMYS containing ten (10) ~~five (5)~~ or more buildings intended for human occupancy, ~~an occupied site~~, or a right-of-way for 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~~, ten (10) ~~five (5)~~ or more buildings intended for human occupancy, or a right-of-way for 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~~, ten (10) ~~five (5)~~ or more buildings intended for human occupancy, or a right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway.

~~*Modern pipe* means any steel pipe that it is not legacy pipe, regardless of the date of manufacture, and has a longitudinal joint factor of 1.0 as defined in § 192.113. Modern pipe refers to all pipe that is not legacy pipe.~~

~~*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.~~

~~*Onshore production facility* or *onshore production operation* means wellbores, equipment, piping, and associated appurtenances confined to the physical acts of extraction or recovery of gas from the earth and the initial preparation for transportation. Preparation for transportation does not necessarily mean the gas will meet "pipeline quality" specifications as may be commonly understood or contained in many contractual agreements. Piping as used in this definition may include individual well flow lines, equipment piping, and transfer lines between production operation equipment components. Production facilities terminate at the furthermost downstream point where: 1) measurement for the purposes of calculating minerals severance occurs; or 2) there is commingling of the flow stream from two or more wells.~~

~~*Significant Seam Cracking* means cracks or crack-like flaws in the longitudinal seam or heat affected zone of a seam weld where the deepest crack is greater than or equal to 10% of wall thickness or the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a failure pressure less than or equal to 110% of SMYS, as determined in accordance with fracture mechanics failure pressure evaluation methods (§§ 192.624(c) and (d)) for the failure mode using conservative Charpy energy values of the crack-related conditions.~~

~~*Significant Stress Corrosion Cracking* means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.~~

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field. Note: A large volume customer (factories, power plants, and institutional users of gas) may receive similar volumes of gas as a distribution center.

~~*Wrinkle bend* means a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples with:~~

1. ~~(1) an amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple or~~
2. ~~(2) with ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.~~
3. ~~(3) If the length of the wrinkle bend cannot be reliably determined, then the following definition should be used:~~

~~*Wrinkle bend* means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds~~ $\cancel{\left(\frac{47{,}000-S}{10{,}000}+1\right)}$ ~~for psi [~~ $\cancel{\left(\frac{324-S}{69}+1\right)}$ ~~for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.~~

- ~~where D is the outside diameter of the pipe, in. (mm),~~
- ~~h is the crest-to-trough height of the ripple, in. (mm), and~~
- ~~S is the maximum operating hoop stress, psi (S/145, MPa).~~

§192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A "*class location unit*" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

~~(d) Records for transmission pipelines documenting class locations and demonstrating how an operator determined class locations in accordance with this section must be retained for the life of the pipeline.~~ After the **[INSERT THE EFFECTIVE DATE OF THE RULE],** records for transmission pipelines documenting class locations and demonstrating how an operator determined class locations in accordance with this section must be retained for the life of the pipeline, or until the documented determination of a new class location for the pipeline, whichever is earliest.

§192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) Each operator must determine and maintain records documenting the beginning and endpoints of each gathering line it operates, including regulated gathering lines as determined in 192.8(b), using the definitions of onshore production facility (or onshore production operation), gas processing plant, gas treatment facility, and onshore gathering line as defined in §192.3 by [insert date 12 months after effective date of the rule] or before the pipeline is placed in operation, whichever is later.

~~(b) Each An operator must determine and maintain records documenting the beginning and endpoints of each gathering line it operates using the definitions of onshore production facility (or onshore production operation), gas processing facility, gas treatment facility, and onshore gathering line as defined in §192.3 by **_[insert date 6 months after effective date of the rule]_** or before the pipeline is placed in operation, whichever is later. use API RP 80 (incorporated by reference, see §192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.~~

~~(c) Each operator must determine and maintain records documenting the beginning and endpoints of each regulated onshore gathering line it operates as determined in §192.8(c) by **_[insert date 6 months after effective date of the rule]_** or before the pipeline is placed into operation, whichever is later.~~

~~(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is~~

~~involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."~~

~~(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.~~

~~(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR §190.9).~~

~~(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.~~

(b) For purposes of Part 191, §§ 192.8 and 192.9, "regulated onshore gathering line" means:

1. Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and
2. As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part —Non-metallic and the MAOP is more than 125 psig (862 kPa). --- Incidental Gathering	Class 2, 3, or 4 location (*see* §192.5) *All incidental gathering in Class 1, 2,3 or 4 locations.*	None.
B	—Metallic and the MAOP	*Area 1.* Class 3 or 4 location	None.

	produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	*Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	—Metallic gathering lines 16" and greater with a MAOP that produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.	*Class 1 location with a nominal diameter of 16" or greater.*	None.

§192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §192.150 and in subpart O of this part.

(c) *Type A lines, ~~Area 1~~ Lines.* An operator of a Type A, ~~Area 1~~ regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§192.13, 192.150, 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.619(e), 192.624 192.710, 192.711, 192.713, and in subpart O of this part. However, an operator of a Type A, ~~Area 1~~ regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type C ~~A~~, ~~Area 2~~ and Type B lines.* An operator of a Type C ~~A~~, ~~Area 2~~ or Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under §192.614;

(4) Establish a public education program under §192.616;

(5) Establish the MAOP of the line under §192.619; and

(6) Install and maintain line markers according to the requirements for transmission lines in §192.707.
(7) Conduct leakage surveys in accordance with §192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with §192.703(c); and
(8) For Type C ~~A~~, ~~Area 2~~ regulated on shore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in §192.615.

~~(e) *Compliance deadlines*. An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.~~ If a regulated onshore gathering line existing on ***[insert the effective date of the rule]*** was not previously subject to this part, an operator has until ***[insert date two years after effective date of the rule]*** to comply with the applicable requirements of this section, unless the Administrator finds a later deadline is justified in a particular case.

~~(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in §192.13 applies.~~

~~(2) If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:~~

~~Requirement~~	~~Compliance deadline~~
~~Control corrosion according to Subpart I requirements for transmission lines~~	~~April 15, 2009.~~
~~Carry out a damage prevention program under §192.614~~	~~October 15, 2007.~~
~~Establish MAOP under §192.619~~	~~October 15, 2007.~~
~~Install and maintain line markers under §192.707~~	~~April 15, 2008.~~
~~Establish a public education program under §192.616~~	~~April 15, 2008.~~
~~Other provisions of this part as required by paragraph (c) of this section for Type A lines~~	~~April 15, 2009.~~

~~(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.~~

(f) If, after ***[insert the effective date of the rule]***, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type C ~~A~~, ~~Area 2~~ and Type B lines and two years for Type A, ~~area 1~~ lines after the line becomes a regulated onshore gathering line to comply with this section.

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

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:
(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
(2) The pipeline qualifies for use under this part according to the requirements in §192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15 2007.
~~Regulated onshore gathering line to which this part did not apply until *(insert effective date of the rule)*~~	~~*(Insert effective date of the rule plus one year)*~~
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15, 2007.
~~Regulated onshore gathering line to which this part did not apply until *(insert effective date of the rule)*~~	~~*(Insert effective date of the rule plus one year).*~~
All other pipelines	November 12, 1970.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

~~(d) 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 must 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. ~~A management of change process must include the following: (1) reason for change, (2) authority for approving changes, (3) analysis of implications, (4) acquisition of required work permits, (5) documentation, (6) communication of change to affected parties, (7) time limitations and (8) qualification of staff.~~

~~(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.~~

~~(2) Records must be reliable, traceable, verifiable, and complete.~~

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

§ 192.67 Records: Materials.

~~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.~~

After [**insert the effective date of this rule**], each operator of an onshore steel transmission pipelines must retain for the life of the pipeline, the Mill Test Report or equivalent.

§ 192.127 Records: Pipe design.

After **[insert the effective date of this rule]** 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.

§ 192.205 Records: Pipeline components.

After **[insert the effective date of this rule],** 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 for valves 2" and larger. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components 2" and larger with material yield strength grades greater than 42,000 psi or greater 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.~~

§192.227 Qualification of welders and welding operators.

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, or Appendix A of API Std 1104 (incorporated by reference, *see* §192.7), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 may weld but may not re-qualify under that earlier edition.
(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.
(c) After **[insert the effective date of this ruling]** records for transmission pipelines demonstrating each individual welder qualification in accordance with this section must be retained for the life of the pipeline.

§192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and
(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:
(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
(2) In the case of a heat fusion, solvent cement, or adhesive joint:
(i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;
(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
(iii) Cut into at least 3 longitudinal straps, each of which is:
(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

~~(e) For transmission pipelines, records demonstrating plastic pipe joining qualifications in accordance with this section must be retained for the life of the pipeline.~~

After **[insert the effective date of this rule]**, each operator of transmission pipelines must retain records demonstrating plastic pipe joining qualifications in accordance with the section for the life of the pipeline.

§192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—
(1) Be applied on a properly prepared surface;
(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
(3) Be sufficiently ductile to resist cracking;
(4) Have sufficient strength to resist damage due to handling (including but not limited to transportation, installation, boring, and backfilling) and soil stress; and
(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

~~(f)~~ After **[insert the effective date of this rule]**, the operator must promptly, but no later than one year after the backfill of 1,000 or more contiguous feet along a steel onshore transmission pipeline following repair or replacement, perform an assessment to ensure integrity of the coating using any assessment methodology permitted by Section 4 of NACE SP0502. The operator must repair any coating damage classified as moderate or severe in accordance with section 4 of NACE SP0502 within one year of the assessment. Each operator of onshore transmission pipelines must retain for the life of the pipeline records documenting the costing assessment findings and any repairs. ~~Promptly, but no later than three months 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 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.~~

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding $2\frac{1}{2}$ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding $2\frac{1}{2}$ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt ~~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.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

~~(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 by checking neighboring test stations until the area of low cathodic protection is determined. Following remediation, the operator must recheck the test stations with low readings to confirm adequate cathodic protection has been restored. ~~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). The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.~~

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

(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.~~ When an operator becomes aware or suspects the presence of electric stray currents, interference surveys must be taken on a periodic basis or evaluation of monitoring stations (if installed) performed ~~including~~, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, or 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 or monitoring to determine the cause of the interference and whether the interference currents are having detrimental effects on the pipeline ~~level could impact the effectiveness of cathodic protection~~; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than eighteen ~~six~~ months after completion of the survey.

§192.485 Remedial measures: Transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7) 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 procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented. Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph 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. Until such time that the requirements within 192.607 have been met; supportable sound engineering assumptions may be used.

§192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—
    (1) It has been tested in accordance with this subpart and §§192.619, 192.620 or ~~192.624~~ to substantiate the maximum allowable operating pressure; and
    (2) Each potentially hazardous leak has been located and eliminated.
(b) The test medium must be liquid, air, natural gas, or inert gas that is—
    (1) Compatible with the material of which the pipeline is constructed;
    (2) Relatively free of sedimentary materials; and
    (3) Except for natural gas, nonflammable.
(c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.
(e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:
    (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
    (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
    (3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

§ 192.607 Pipeline Records: Onshore steel transmission pipelines.

(a) For each segment of onshore, steel, gas transmission pipeline installed after [insert the effective date of the rule], each operator must keep and maintain ~~reliable~~, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components as follows:

(1) For line pipe and fittings, records must document diameter, wall thickness, grade (yield strength), 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.

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

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

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

(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 ***[insert date that is 180 days after the effective date of the 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, specified minimum yield strength, and pipe class for longitudinal joint factor determination per §192.113. ~~grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.~~

(2) For valves, records must document one of the following ~~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 one of the following ~~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 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, replacements, relocations 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 number of excavations determined to be necessary by the operator through statistical analysis. ~~minimum number of excavations as follows.~~

~~(i)~~ The operator must identify ~~define a separate population of~~ each segment of pipeline which has undocumented or inadequately documented records with which to establish an MAOP. For the purposes of §192.607, "pipeline segment" shall mean a continuous length of pipe (including weld joints) uninterrupted by any significant change in flow characteristics that includes similar physical characteristics or operating history. ~~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) For each pipeline segment ~~population defined~~ identified according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is determined in accordance with either (A) or (B)~~the lesser of the following~~:

(A) The lesser of (i) or (ii);

(i) 150 excavations; or

(ii) If the segment is less than 150 miles, a number of excavations equal to the pipeline segment's ~~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.~~

~~(B)~~ 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.~~[1]

(B) Alternatively, an operator may determine the number of excavations through statistical analysis.

~~(iii)~~ At each excavation, test for material properties must determine the properties that are necessary to calculate MAOP and for use in remaining strength calculations. ~~operators must conduct sufficient testing on the material properties of the pipeline with which to determine an MAOP. 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 to conservatively account for measurement inaccuracy and uncertainty based upon

[1] TPA would suggest eliminating this language because if testing is only done when an excavation takes place, operators will not be able to choose the sites to this level of specificity. However, TPA does agree that testing needs to generally be proportional across each segment of pipe.

comparison with destructive test results. ~~in metallurgy and fracture mechanics to produce results that~~ [2] ~~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 excavations determined to be necessary by the operator through statistical analysis. ~~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.~~

(vi) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with the number appropriate to achieve the accuracy requirements established in (iv) above in accordance with a qualified testing procedure. ~~at a minimum of five places each circumferential quadrant of the pipe. for a minimum total of 20 test readings at each pipe cylinder location.~~

(vii) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with an applicable manufacturing specification. ~~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 unknown material properties are consistent with all available information on ~~for~~ each pipeline or are more conservative than current assumptions (such as, thicker walled pipe, smaller diameter, or higher grade), ~~population,~~ then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not ~~consistent~~ as conservative as the current assumptions ~~with existing expectations~~ based on all available information for each ~~population~~ pipeline, then the operator must modify their material documentation program, testing frequency to address these inconsistencies. ~~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 one of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. ~~the ANSI rating and material grade (to assure compatibility with pipe ends).~~

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[2] PHMSA does not do this now and TPA is not confident an appropriate level of resources and expertise exist at PHMSA in order to approve new technologies in a quick and efficient manner.

(x) 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.

(xi) 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) 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.

(xii) 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, unless the current MAOP is unknown and is based on an assumed yield strength of 24 ksi in accordance with §192.107(b)(2). ~~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.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).

~~(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of damage to 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.~~

Following an event that is likely to cause damage to pipeline facilities due to the intensity of the event and the environment in which the onshore transmission pipeline facilities operate, an operator must inspect all its onshore transmission pipeline facilities in the area of the event to determine if any damage has occurred to the pipeline facilities that would prevent continued safe operation of the pipeline facilities.

(1) Inspection method. An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine damage

and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) Time period. The inspection required under the introductory text of paragraph (c) of this section must commence 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 availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this section~~, whichever is sooner~~.

(3) Remedial action. An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under the introductory paragraph (c) in this section. Such actions might include, but are not limited to:

  (i) Reducing the operating pressure or shutting down the pipeline;
  (ii) Modifying, repairing, or replacing any damaged pipeline facilities;
  (iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
  (iv) Performing additional patrols, surveys, tests, or inspections;
  (v) Implementing emergency response activities with Federal, State, or local personnel; or
  (vi) Notifying affected communities of the steps that can be taken to ensure public safety.

§192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

  (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
  (i) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

  (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
  (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—			
	Installed before (Nov. 12, 1970)	**Installed after (Nov. 11, 1970) and before (Date of New Rule)**	**Installed after (Date of New Rule – 1 Day)**	**Converted under §192.14**
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25

3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 but before (***insert effective date of the rule)*** —Onshore gathering line that first became subject to this part (other than §192.612) on or after (***insert effective date of the rule)*** —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later ***(Insert date that is one year after the effective date of the rule),*** or date line becomes subject to this part, whichever is later. March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering, ~~material records, including material properties identified in accordance with § §192.607, and~~ the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

~~(e) Notwithstanding the requirements in paragraphs (a) through (d) above, onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624 using one or more of the following:~~ **ALTERNATE: Notwithstanding the requirements in paragraphs (a) through (d) above, onshore steel transmission pipelines that meet the criteria specified in §192.624)(a) must verify MAOP in accordance with that section.**

~~(1) Method 1: Pressure Test - Pressure test in accordance with § 192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with § 192.624(c)(1)(ii), as applicable;~~

~~(1) Method 2: Pressure Reduction - Reduction in pipeline maximum allowable operating pressure in accordance with § 192.624(c)(2);~~

~~(2) Method 3: Engineering Critical Assessment – Engineering assessment and analysis activities in accordance with § 192.624(c)(3);~~

~~(3) Method 4: Pipe Replacement - Replacement of the pipeline segment in accordance with § 192.624(c)(4);~~

~~(4) Method 5: Pressure Reduction for Segments with Small PIR and Diameter - Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or~~

~~(5) Method 6: Alternative Technology - Alternative procedure in accordance with § 192.624(c)(6).~~

(f) For onshore steel transmission pipelines installed after **[insert effective date of this rule],** operators must maintain ~~all~~ records necessary to ~~establish and~~ document the MAOP of each onshore steel transmission pipeline as long as the pipe or pipeline remains in service. Records that may 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. For onshore steel transmission pipeline installed after [one year after the effective date of rule], records used to document the MAOP must be ~~reliable,~~ traceable, verifiable, and complete.

(e) Compliance with §192.624 as it relates to verification of a pipeline segment's MAOP is sufficient to establish an MAOP for the purposes of this Section.

§ 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~~ conduct a one-time verification of the maximum allowable operating pressure using one ~~or more~~ of the methods specified in § 192.624(c)(1) through (6):

(1) Unless an operator has already taken action to address a reported incident, ~~The~~ if a pipeline segment has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").

(2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A class 3 or class 4 location

(3) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before ***[insert effective date of rule***] and is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").

(b) ***Completion Date.*** For pipelines installed before **[*insert the effective date of rule*]**, all actions required by this section must be completed according to the following schedule:

(1) The operator must develop and document a plan for completion of all actions required by this section by ***[insert date that is 1 year after the effective date of rule]***.

(2) The operator must complete all actions required by this section on at least 50% of the mileage of locations that meet the conditions of § 192.624(a) by ***[insert date that is 8 years after the effective date of rule].***

(3) The operator must complete all actions required by this section on 100% of the mileage of locations that meet the conditions of § 192.624(a) by ***[insert date that is 15 years after the effective date of rule].***

(4) If operational and environmental constraints limit the operator from meeting the deadlines in § 192.614 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e). The notification must include an up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(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 using one of the following methods:

(1) Method 1: Pressure test.

(i) Perform a pressure test in accordance with Subpart J~~§ 192.505(c).~~ The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

~~(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident, as defined by § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with § 192.506. The maximum allowable operating pressure will~~

~~be equal to the test pressure specified in § 192.506(c) divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).~~

(iii) If the operator has reason to believe any pipeline segment 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 (d) of this section.

(2) Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be the existing maximum allowable operating pressure ~~no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[insert effective date of rule]*~~ divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). ~~The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period.~~ The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

~~(i) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:~~

~~(A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[insert effective date of rule]*, divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.~~

~~(B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[insert effective date of rule]*, divided by 2.00.~~

~~(ii) 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 (d) of this section.~~

~~(iii) Future uprating of the segment in accordance with subpart K is allowed if the maximum allowable operating pressure is established using Method 2.~~

(iv) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.

~~(3) Method 3: Engineering Critical Assessment—Conduct an engineering critical assessment and analysis (ECA) to establish the material 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), 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 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. 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™, 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 the operator must determine a Charpy v-notch toughness based upon the material documentation program specified in § 192.607 or use conservative values for Charpy v-~~

~~notch toughness as follows: body toughness of less than or equal to 5.0 ft-lb and seam toughness of less than or equal to 1 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 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) or ultrasonic testing (UT) tool.~~

~~(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) 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 subpart O, 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).~~

(4) Method 4: Pipe Replacement - Replace the pipeline segment.

(5) Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter – Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 150 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure as follows:

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the ~~highest~~ ~~actual~~ maximum allowable operating pressure of ~~sustained by~~ the pipeline ~~during 18 months preceding~~ ~~***[insert effective date of rule]***~~, divided by 1.1. ~~The highest actual sustained pressure must have been reached for a minimum cumulative duration~~

~~of eight hours during one continuous 30-day period.~~ The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location specific operating pressure at each location);

~~(ii) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;~~

~~(iii) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for 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;~~

~~(iv) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;~~

~~(v) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and~~

~~(vi) Odorize gas transported in the segment, in accordance with § 192.625;~~

~~(vii) 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).~~

~~(viii) Under Method 5, future uprating of the segment in accordance with subpart K is allowed.~~

(6) Method 6: Alternative Technology - Operators may use an **a**lternative technical evaluation process that provides a sound engineering basis for establishing maximum allowable operating pressure. 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 § 192.624(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.~~ The notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, 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.

(ii) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

~~(iii) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this Part and industry standards;~~

(iv) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

(v) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of PFP quantified as a fraction of specified minimum yield strength;

(vi) 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);

(vii) Remediation methods with proven technical practice;

~~(viii) Schedules for assessments and remediation;~~

(ix) Operational monitoring procedures;

(x) Methodology and criteria used to justify and establish the maximum allowable operating pressure; and

(xi) Documentation requirements for the operator's process, including records to be generated.

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

~~(1) 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 perform fracture mechanics modeling for failure stress pressure and crack growth analysis to determine the remaining life of the pipeline at the maximum allowable operating pressure based on the applicable test pressures in accordance with § 192.506 including the remaining crack flaw size in the pipeline segment, any pipe failure or leak mechanisms identified during pressure testing, pipe characteristics, material toughness, failure mechanism for the microstructure(ductile and brittle or both), location and type of defect, operating environment, and operating conditions including pressure cycling. Fatigue analysis must be performed using a recognized form of the Paris Law as specified in Battelle's Final Report No. 13-021; Subtask 2.5 (incorporated by reference, see § 192.7) or other technically appropriate engineering methodology validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life. When assessing other degradation processes, the analysis must be performed using recognized rate equations whose applicability and validity is demonstrated for the case being evaluated. For cases involving calculation of the critical flaw size, conservative remaining life analysis must assess the smallest critical sizes and use a lower-bound toughness. For cases dealing with an estimating of the defect sizes that would survive a hydro test pressure, conservative remaining life analysis that must assess the largest surviving sizes and use upper-bound values of material strength and toughness. The analysis must include a sensitivity analysis to determine conservative estimates of time to failure for cracks. Material strength and toughness values used must reflect the local conditions for growth, and use data that is case specific to estimate the range of strength and toughness for such analysis. When the strength and toughness and limits on their ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the type of assessment being performed, as follows:~~

~~(i) For an assessment using a hydrostatic pressure test use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb and a flow stress equal to the minimum specified ultimate tensile strength of the base pipe material. The purpose of using the high level of Charpy energy and flow stress (equal to the ultimate tensile strength) is for an operator to calculate the largest defects that could have survived a given level of~~

~~hydrostatic test. The resulting maximum-size defects lead to the shortened predicted times to failure;~~

~~(ii) For ILI assessments unless actual ranges of values of strength and toughness are known, the analysis must use the specified minimum yield strength and the specified minimum ultimate tensile strength and Charpy toughness valves lower than or equal to: 5.0 ft-lb for body cracks; 1.0 ft-lb for ERW seam bond line defects such as cold weld, lack of fusion, and selective seam weld corrosion defects.~~

~~(iii) The sensitivity analysis to determine the time to failure for a crack must include operating history, pressure tests, pipe geometry, wall thickness, strength level, flow stress, and operating environment for the pipe segment being assessed, including at a minimum the role of the pressure-cycle spectrum.~~

~~(2) If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must use a conservative Charpy energy value to determine the toughness based upon the material documentation program specified in § 192.607; or use maximum Charpy energy values of 5.0 ft-lb for body cracks; 1.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects as documented in Battelle Final Reports ("Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications" - Task 1.4), 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 appropriate technology or technical publications that an operator demonstrates can provide a conservative Charpy energy values of the crack-related conditions of the line pipe.~~

~~(3) The analysis must account for metallurgical properties at the location being analyzed (such as in the properties of the parent pipe, weld heat affected zone, or weld metal bond line), and must account for the likely failure mode of anomalies (such as brittle fracture, ductile fracture or both). If the likely failure mode is uncertain or unknown, the analysis must analyze both failure modes and use the more conservative result. Appropriate fracture mechanics modeling for failure stress pressures in the brittle failure mode is the Raju/Newman Model (Task 4.5) and for the ductile failure mode is the Modified LnSec (Task 4.5) and Raju/Newman Models or other proven equivalent engineering fracture mechanics models for determining conservative failure pressures may be used.~~

~~(4) If the predicted remaining life of the pipeline calculated by this analysis is 5 years or less, then the operator must perform a pressure test in accordance with paragraph (c)(1) above or reduce the maximum allowable operating pressure of the pipeline in accordance with paragraph § 192.624(c)(2) above to establish the maximum allowable operating pressure within 1-year of analysis;~~

~~(5) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired, but within 15 years. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired. If the analysis results show that a 50% remaining life reduction does not give a sufficient safety factor based upon technical evaluations then a more conservative remaining life safety factor must be used.~~

(6) ~~The analysis required by this paragraph (d) must be reviewed and confirmed by a subject matter expert in both metallurgy and fracture mechanics.~~ [See AGA's comments on fracture mechanics].

(e) ***Notifications.*** An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:

(1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001;

(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or

(3) Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.

(4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(f) ***Records.*** For gas transmission pipelines that meet the applicability of §192.624, after [*insert effective date of rule*] ~~Each~~ operators must keep for the life of the pipeline ~~reliable~~, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.

§ 192.710 Pipeline assessments.

(a) Applicability

~~(1)~~ This section applies to onshore transmission pipeline segments that are capable of assessment by free swimming in-line inspection tools under normal operating conditions outside of ~~located in:~~

~~(i) A class 3 or class 4 location; or~~

~~(ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").~~

(2) ~~This section does not apply to a pipeline segment located in a~~ High Consequence Area as defined in § 192.903.

(b) *General.*

(1) An operator must perform initial assessments in accordance with this section no later than ***[insert date that is ~~15~~ 20 years after the effective date of the rule]*** with 50% of the mileage assessed within 10 years of [***insert the effective date of the rule***] and the remaining 50% assessed by ***[insert date that is 20 years after the effective date of the rule]*** and periodic reassessments every 20 years thereafter, or a shorter reassessment internal based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as otherwise necessary to ensure public safety.

(2) *Prior assessment.* An operator may use a prior assessment conducted before ***[Insert effective date of the final rule]*** as an initial assessment for the segment, if the assessment meets the Subpart O requirements for in-line inspection. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(1) of this section.

(3) *MAOP verification.* 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.

(c) *Assessment Method.* The initial assessments and the reassessments required by paragraph (b) must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible and must be performed using one or more of the following methods:

(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, and any other threats to which the segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;

(3) "Spike" hydrostatic pressure test in accordance with § 192.506;

(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);

(5) Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of 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 (d)(5) of this section.~~ An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 or 192.929; or

(7) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

(8) For segments with MAOP less than 30% of the SMYS, an operator may ~~must~~ assess for the threats of external and internal corrosion, as follows:

(i) *External corrosion.* An operator must take one of the following actions to address external corrosion on a low stress segment:

(A) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(B) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—

(1) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and

(2) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

~~(ii)~~ *Internal corrosion.* To address the threat of internal corrosion on a low stress segment, an operator with pipelines susceptible to the presence of corrosive gasses must assess the internal corrosion using appropriate assessment methods. —

~~(A) Conduct a gas analysis for corrosive agents at least twice each calendar year;~~

~~(B) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and~~

~~(C) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (ii)(A)-(ii)(B) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.~~

(d) *Data analysis*. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section 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 tool performance) in identifying and characterizing anomalies.

(e) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than ~~180~~ 360 days after an assessment, obtain sufficient information about a condition to make the determination required under paragraph (d), unless the operator can demonstrate that that ~~180-~~ 360 days is impracticable.

(f) *Remediation*. An operator must comply with the requirements in § 192.713 if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) (g) *Consideration of information*. An operator must consider all available information about a pipeline in complying with the requirements in paragraphs (a) through (f).

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

~~(a) 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.\~~

(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.

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

(b) *General.* Each 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.

(c) *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.

(d) *Remediation schedule*. For pipelines not located in high consequence areas, an operator must complete the remediation of a condition according to the following schedule:

(1) *Immediate repair conditions*. An operator must repair the following conditions immediately upon discovery:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 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 with stress concentration factors such as scratches, gouges, grooves, or stress risers.~~that has any indication of metal loss, cracking or a stress riser~~.

(iii) Metal loss 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 risk 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).~~

(vii) 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 remediation of a condition specified in paragraph (d)(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 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. 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. 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, whichever is lower.

(3) *Two-year conditions*. An operator must repair 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) 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.

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

(v) ~~Predicted~~ ~~m~~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, 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.

(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.

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after ***[insert ~~6 months~~ 18 months after effective date of rule]***, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of in-line inspection tools, scrapers, or spheres, if pressure has not been relieved.

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

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as manufacturing, welding/fabrication or equipment ~~construction~~ defects;

(3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and

(4) Human error such as operational mishaps and design and construction mistakes.

(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 consider ~~gather and evaluate~~ the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI B31.8S, and must evaluate all relevant threats which are applicable to their pipelines. ~~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.~~ ~~The evaluation must analyze both the covered segment and similar non-covered segments, and must:~~

(1) Risk Factors to Consider:~~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) Year of installation;

(vi) Bending method;

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

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

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

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

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

(xii) Soil, backfill;

(xiii) 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) Cathodic protection installed, including but not limited to type and location;
(xv) Coating type;
(xvi) Gas quality;
(xvii) Flow rate;
(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
(xix) Class location;
(xx) 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) Coating condition;
(xxii) CP system performance;
(xxiii) Pipe wall temperature;
(xxiv) 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) Outer Diameter/Inner Diameter corrosion monitoring;
(xxvi) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;
(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;
(xxviii) 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;
(xxix) Repairs;
(xxx) Vandalism;
(xxxi) External forces;
(xxxii) Audits and reviews;

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

(xxxiv) Aerial photography;

(xxxv) 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, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ 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 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 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 should consider ~~must~~:

~~follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.~~

(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.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(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 such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading 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

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine the risk of failure from ~~If an operator identifies the threat of~~ manufacturing and construction defects (including seam defects) in the covered segment. ~~an operator must analyze the covered segment to determine the risk of failure from these defects.~~ The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J 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 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).

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

§192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each ~~depending on the~~ threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917). 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 groves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, ~~environmentally assisted cracking, and girl weld cracks), hard spots with cracking~~, 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 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;

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(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~~;

(4) Excavation and *in situ* direct examination by means of visual examination, 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);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of 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 applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949 ~~and receive a "no objection letter" from the Associate Administrator of Pipeline Safety~~. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206-2006 ~~ASME/ANSI B31.8S~~ (incorporated by reference, *see* §192.7), ~~section 6.4 and appendix B2.~~ The Dry Gas (DG) ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas (see definition §192.3), and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment ~~provide notification~~ in accordance with §192.921 (a)(4) or §192.937(c)(4).

~~(c)~~ *The ICDA plan.* An operator must develop and follow an ICDA plan that ~~provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.~~ meets all requirements and recommendations contained in NACE SP0206-2006 and that implements all four steps of the DG-ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) *Preassessment.* ~~In the preassessment stage,~~ An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the preassessment step of the ICDA process. ~~gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe~~

~~segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—~~

(i) ~~All data elements listed in appendix A2 of ASME/ANSI B31.8S;~~

(ii) ~~Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;~~

(iii) ~~Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and~~

(iv) ~~Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.~~

(2) *Indirect Inspection.* ~~*ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, *see* §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.~~ An operator must comply with the requirements and recommendations in NACE SP0206-2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206-2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed Examination. Identification of locations for excavation and direct examination.* ~~An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region.~~ An operator must comply with the requirements and recommendations in NACE SP0206-2006 in conducting the detailed examination step of the ICDA process. ~~In the location~~

~~identification process,~~ In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each ICDA Region ~~within a covered segment~~ and must perform a ~~direct~~ detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933; if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

(ii) ~~As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and~~ Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933 or § 192.713, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator~~'s plan~~ must comply with the requirements and recommendations in NACE SP0206-2006 in performing the post assessment step of the ICDA process. ~~provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified.~~ In addition the post-assessment requirements and recommendations in NACE SP0206-2006, the evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; ~~and~~

(ii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region ~~covered segment~~.-If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933. ~~At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.~~

(A) Conduct excavations of, and detailed examinations at, ~~covered segments at~~ locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ILI tools capable of detecting internal corrosion ~~another integrity assessment method allowed by this subpart.~~

(5) *Other requirements.* The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (*e.g.,* ICDA feasibility, definition of ICDA Regions and Sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) ~~Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and~~

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

§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); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, *see* §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or ~~by~~ reduce~~ing~~ the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, the operator may utilize assumptions based on available records and sound engineering judgment ~~pipe and material properties used in the remaining strength calculations must be based 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 another 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.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

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

(d) *Special requirements for scheduling remediation—*

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

(i) 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 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, the operator may utilize assumptions based on available records and sound engineering judgment ~~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.

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

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper $^2/_3$ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

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

(iii) 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.

(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.

(viii) Metal loss less than 10% affecting a detected longitudinal seam other than those seam types listed in §192.933(d)(1)(v).

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

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom $^1/_3$ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper $^2/_3$ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

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

(a) *General requirements.* An operator must consider takinge 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: correction of the root cause of past incidents to prevent reoccurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventative and mitigate measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical and chemical properties for unknown properties that are need to assure integrity or substantive MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.~~

(b) Third party damage and outside force damage—

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, loading, longitudinal, or later forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, relocating the line, or geospatial, GIS, and deformation in-line inspections.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.
   (1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and
   (2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.
   (3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient or equivalent ~~electrical surveys~~ are impractical).

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

(f) *Internal corrosion.* 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—
   (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 continuous gas quality monitoring equipment.
   (3) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and 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 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 or utilize monitoring stations ~~(at times when voltages are at the highest values for a time period of at least 24-hours)~~ to determine ~~detect~~ the ~~presence and~~ level of any electrical current that could impact external corrosion where interference is suspected and remediate AC interference currents to at least 20 amps per meter squared unless the operator provides and documents an engineering justification for a lesser level of remediation;

(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~~ 18 months 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~~ 20 Amps per meter squared must be remediated unless sound engineering supports a lower level or remediation. Any location with current densities above 50 amps per meter squared or greater, operators do not have discretion and the location must be remediated.

(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 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).~~

(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).~~

(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 after assessment finding.~~

(iv) ~~Perform periodic assessments as follows:~~

(A) ~~Conduct periodic close interval surveys with current interrupted 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.~~

(3) Control external corrosion through cathodic protection as follows:

(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(ii) ~~Remediate insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (i) above, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.~~

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

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917, which incorporates an analysis of updated pipe design, construction, operation, maintenance, and integrity information. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933). The evaluation must identify the threats specific to each covered segment, including interacting threats and the risk represented by these threats, and identify additional preventive and mitigative actions (§192.935). ~~An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.~~

(c) *Assessment methods.* ~~In conducting the integrity reassessment,~~ An operator must assess the integrity of the line pipe in ~~the~~ each covered segment by any one or more of the following methods for each ~~as appropriate for the~~ threat~~s~~ to which the covered segment is susceptible (*see* §192.917). ~~or by confirmatory direct assessment under the conditions specified in §192.931.~~ An operator must select the method or methods 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.

~~(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, and any other threats to which the covered segment is susceptible. When performing an assessment using and in-line inspection tool, 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.~~ comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section 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 tool performance) in identifying and characterizing anomalies.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. The use of pressure testing is appropriate for time dependent threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms and for manufacturing and related defect threats, including defective pipe and pipe seams.

(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.

(4) Excavation and *in situ* direct examination by means of visual examination, 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). An operator must explicitly consider uncertainties in in situ direct examination results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, and usage unity chart plots or equivalent for determining uncertainties and verifying performance on the type defects being evaluated) in identifying and characterizing anomalies.

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

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

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949 ~~and receive a "no objection letter" from the Associate Administrator of Pipeline Safety~~. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.