In consideration of the foregoing, PHMSA is amending 49 CFR part 195 as follows:
PART 195 – TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. Revise the authority citation for part 195 to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et.seq.,* and 49 CFR 1.97.

2. Amend § 195.1 by adding paragraph (a)(5) and revising paragraphs (b)(2) and (b)(4) to read as follows:

§ 195.1 Which pipelines are covered by this part?

(a) * * *

(5) For purposes of the reporting requirements in subpart B of this part, any gathering line not already covered under paragraphs (a)(1), (2), (3) or (4) of this section.

(b) * * *

(2) Except for the reporting requirements of subpart B of this part, see § 195.13, transportation of a hazardous liquid through a pipeline by gravity.

* * * * *

(4) Except for the reporting requirements of subpart B of this part, see § 195.15, transportation of petroleum through an onshore rural gathering line that does not meet the definition of a "regulated rural gathering line" as provided in § 195.11. This exception does not apply to gathering lines in the inlets of the Gulf of Mexico subject to **§** 195.413.

* * * * *

3. Amend § 195.2 by revising the definition for "*Hazardous liquid*" to read as follows:

§ 195.2 Definitions.

* * * * *

Hazardous liquid means petroleum, petroleum products, anhydrous ammonia, and ethanol or other non-petroleum fuel, including biofuel, which is flammable, toxic, or would be harmful to the environment if released in significant quantities.

* * * * *

4. In §195.3, amend paragraph (g)(3) by removing "§195.591" and adding "§§195.120 and 195.591" in its place.

5. Add § 195.13 to subpart A to read as follows:

§ 195.13 What requirements apply to pipelines transporting hazardous liquids by gravity?

(a) *Scope.* Pipelines transporting hazardous liquids by gravity must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period.*

(1) *Annual reporting*. Comply with the annual reporting requirements in subpart B of this part by March 31, 2021.

(2) *Accident and safety-related reporting*. Comply with the accident and safety-related condition reporting requirements in subpart B of this part by January 1, 2021.

(c) *Exceptions.*

(1) This section does not apply to the transportation of a hazardous liquid in a gravity line that meets the definition of a low-stress pipeline, travels no farther than 1 mile from a facility boundary, and does not cross any waterways used for commercial navigation.

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gravity line.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gravity line.

6. Add § 195.15 to subpart A to read as follows:

§ 195.15 What requirements apply to reporting-regulated-only gathering lines?

(a) *Scope*. Gathering lines that do not otherwise meet the definition of a regulated rural gathering line in § 195.11 and any gathering line not already covered under § 195.1(a)(1), (2), (3) or (4) must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period*.

(1) *Annual reporting*. Operators must comply with the annual reporting requirements in subpart B of this part by March 31, 2021.

(2) *Accident and safety-related condition reporting*. Operators must comply with the accident and safety-related condition reporting requirements in subpart B of this part by January 1, 2021.

(c) *Exceptions*.

(1) This section does not apply to those gathering lines that are otherwise excepted under § 195.1(b)(3), (b)(7), (b)(8), (b)(9), or (b)(10).

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

7. Add § 195.65 to subpart B to read as follows:

§ 195.65 Safety data sheets.

(a) Each owner or operator of a hazardous liquid pipeline facility, following an accident involving a pipeline facility that results in a hazardous liquid spill, must provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center.

(b) Definitions. In this section:

(1) *Federal On-Scene Coordinator.* The term "Federal On-Scene Coordinator" has the meaning given such term in section 311(a) of the Federal Water Pollution Control Act (33 U.S.C. 1321(a)).

(2) *National Response Center*. The term "National Response Center" means the center described under 40 CFR 300.125 (a).

(3) *Safety data sheet.* The term "safety data sheet" means a safety data sheet required under 29 CFR 1910.1200.

8. Revise § 195.120 to read as follows:

§ 195.120 Passage of internal inspection devices.

(a) *General*. Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each main line section of a pipeline where the line pipe, valve, fitting or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102 (incorporated by reference, *see* § 195.3).

(b) *Exceptions*. This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs;

(5) ~~Sizes of~~ Pipe for which an instrumented internal inspection device is not commercially available; and

(6) Offshore pipelines, other than main lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities.

~~(7) Other piping that the Administrator under §190.9 of this chapter finds a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.~~

~~(c)An operator encountering emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.~~

(c) *Impracticability*. An operator may file a petition under § 190.9 for a finding that the requirements in paragraph (a) should not be applied to a pipeline for reasons of impracticability.

(d) *Emergencies*. An operator need not comply with paragraph (a) of this section in constructing a new or replacement segment of a pipeline in an emergency. Within 30 days after discovering the emergency, the operator must file a petition under §190.9 for a finding that requiring the design and construction of the new or replacement pipeline segment to accommodate passage of instrumented internal inspection devices would be impracticable as a result of the emergency. If PHMSA denies the petition, within 1 year after the date of the notice of the denial, the operator must modify the new or replacement pipeline segment to allow passage of instrumented internal inspection devices.

9. Revise § 195.134 to read as follows:

§ 195.134 ~~CPM~~ Leak detection.

(a) *Scope.* This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid).

(b) *General.*

(1) For each pipeline constructed prior to October 1, 2019.

Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1,2024.

(2) For each pipeline constructed on or after October 1, 2019.

Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2020.

(c) *CPM leak detection systems*. A new computational pipeline monitoring (CPM) leak detection system or replaced component of an existing CPM system must be designed in accordance with the requirements in section 4.2 of API RP 1130 (incorporated by reference, see § 195.3) and any other applicable design criteria in that standard.

(d) *Exception*. The requirements of paragraph (b) of this section do not apply to offshore gathering or regulated rural gathering lines.

10. Revise § 195.401 by adding paragraph (b)(3) to read as follows.

§ 195.401 General requirements.

* * * * *

(b) * * *

(3) *Prioritizing repairs*. An operator must consider the risk to people, property, and the environment in prioritizing the correction of any conditions referenced in paragraphs (b)(1) and (2) of this section.

* * * * *

11. Add § 195.414 to read as follows:

§ 195.414 Inspections of pipelines in areas affected by extreme weather and natural disasters.

(a) *General*. Following an extreme weather event or natural disaster that has the likelihood of damage to infrastructure by the scouring or movement of the soil surrounding the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(b) *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 the extent of any damage and the need for the additional assessments required under paragraph (a) of this section.

(c) *Time period*. The inspection required under paragraph (a) 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 required to perform the inspection as determined under paragraph (b) of this section. In the event that the operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(d) *Remedial action*. An operator must take prompt and 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 paragraph (a) of this section. Such actions might include, but are not limited to:

(1) Reducing the operating pressure or shutting down the pipeline;

(2) Modifying, repairing, or replacing any damaged pipeline facilities;

(3) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(4) Performing additional patrols, surveys, tests, or inspections;

(5) Implementing emergency response activities with Federal, State, or local personnel; and

(6) Notifying affected communities of the steps that can be taken to ensure public safety.

12. Add § 195.416 to read as follows:

§ 195.416 Pipeline assessments.

(a) *Scope*. This section applies to onshore line pipe that can accommodate inspection by means of in-line inspection tools and is not subject to the integrity management requirements in § 195.452.

(b) *General*. An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029.

and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.

(c) *Method.* Except as specified in paragraph (d) of this section, an operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). When performing an assessment using an in-line inspection tool, an operator must comply with § 195.591. An operator must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies. If this is impracticable based on operational limits, including operating pressure, low flow, and pipeline length or availability of in-line inspection tool technology for the pipe diameter, then the operator must perform the assessment using the appropriate method(s) in paragraphs (c)(1), (2), or (3) of this section for the range of relevant threats being assessed. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in §195.106(e) or lap-welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies. The following alternative assessment methods may be used as specified in this paragraph:

(1) A pressure test conducted in accordance with subpart E of this part;

(2) External corrosion direct assessment in accordance with § 195.588; or

(3) Other technology in accordance with paragraph (d).

(d) *Other technology.* Operators may elect to use other technologies if the operator can demonstrate the technology can provide an equivalent understanding of the condition of the line pipe for threat being assessed. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by:

(1) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590; or

(2) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager by facsimile to (202) 366-7128.

(3) Prior to conducting the "other technology" assessments, the operator must receive a notice of "no objection" from the PHMSA Information Services Manager or Designee.

(e) *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. Operators must consider uncertainties in any reported results (including tool tolerance) as part of that analysis.

(f) *Discovery of condition*. For purposes of § 195.401(b)(1), discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination required under paragraph (e) of this section, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA and provide an expected date when adequate information will become available. This notification must be made in accordance with § 195.452 (m).

(g) *Remediation*. An operator must comply with the requirements in § 195.401 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with paragraphs (e) and (f) of this section.

(h) *Consideration of information*. An operator must consider all relevant information about a pipeline in complying with the requirements in paragraphs (a) through (g) of this section.

13. Revise § 195.444 to read as follows:

§ 195.444 ~~CPM~~ Leak detection.

(a) *Scope.* Except for offshore gathering and regulated rural gathering pipelines, this section applies to all hazardous liquid pipelines transporting liquid in single phase (without gas in the liquid).

(b) *General.* A pipeline must have an effective system for detecting leaks in accordance with §§ 195.134 or 195.452, as appropriate. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must consider the following factors—length and size of the pipeline, type of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history.

(c) *CPM leak detection systems.* Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 (incorporated by reference, see § 195.3) in operating, maintaining, testing, record keeping, and dispatcher training of the system.

14. Amend § 195.452 by:

a. Revising paragraphs (a)(3) and (b)(1), the introductory text of paragraph (c)(1)(i), paragraphs (c)(1)(i)(A), (d), (e)(1)(vii), and (g), the introductory text of paragraph (h)(1), and paragraph (h)(2);

b. Amending paragraph (i)(2)(viii) by removing the period at the end of the last sentence and adding in its place a ";"

c. Adding paragraph (i)(2)(ix);

d. Revising paragraph (j)(2);

e. Adding paragraphs (n) and (o).

The revisions and additions read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) * * *

(3) Category 3 includes pipelines constructed or converted after May 29, 2001, <u>and low-stress pipelines in rural areas under § 195.12.</u>

* * * * *

(b) * * *

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table no later than the date in the second column:

Pipeline	**Date**
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	Date the pipeline begins operation <u>or as provided in § 195.12 for low stress pipelines in rural areas.</u>

* * * * *

(c) * * *

(1) * * *

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by <u>in-line inspection tool(s) described in paragraph (A) under paragraph (c)(1)(i) of this section for the range of relevant threats to the pipeline segment. If it is impracticable based upon the construction of the pipeline (e.g., diameter changes, sharp bends, and elbows) or operational limits including operating pressure, low flow, pipeline length, or availability of in-line inspection tool technology for the pipe diameter, then the operator must use the appropriate method(s) in paragraphs (B), (C), or (D) under paragraph (c)(1)(i) for the range of relevant threats to the pipeline</u>

segment. The methods an operator selects to assess low-frequency electric resistance welded pipe, pipe with a seam factor less than 1.0 as defined in § 195.106(e) or lap-welded pipe susceptible to longitudinal seam failure, must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies.

(A) In-line inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. For pipeline segments with an identified or probable risk or threat related to cracks (such as at pipe body or weld seams) based on the risk factors specified in paragraph (e), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an in-line inspection tool, an operator must comply with § 195.591. An operator using this method must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies;

* * * * *

(d) *When must operators complete baseline assessments?*

(1) *All pipelines.* An operator must complete the baseline assessment before a new or conversion-to-service pipeline begins operation through the development of procedures, identification of high consequence areas, and pressure testing of could-affect high consequence areas in accordance with § 195.304.

(2) *Newly identified areas.* If an operator obtains information (whether from the information analysis required under paragraph (g) of this section, Census Bureau maps, or any other source) demonstrating that the area around a pipeline segment has changed to meet the definition of a high consequence area (*see* §195.450), that area must be incorporated into the operator's baseline assessment plan within 1 year from the date that the information is obtained. An operator must complete the

baseline assessment of any ~~line pipe~~ pipeline segment that could affect a newly identified high consequence area within 5 years from the date an operator identifies the area.

* * * * *

(e) * * *

(1) * * *

(vii) Local environmental factors that could affect the pipeline (e.g., seismicity, corrosivity of soil, subsidence, climatic);

* * * * *

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (*see* paragraph (j) of this section), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. Operators must continue to comply with the data integration elements specified in § 195.452(g) that were in effect on October 1, 2018, until October 1, 2022. Operators must begin to integrate all the data elements specified in this section starting October 1, 2020, with all attributes integrated by October 1, 2022. This analysis must:

(1) Integrate information and attributes about the pipeline that include, but are not limited to:

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

(ii) Pipe coating, including girth weld coating;

(iii) Maximum operating pressure (MOP) and temperature;

(iv) Endpoints of segments that could affect high consequence areas (HCAs);

(v) Hydrostatic test pressure including any test failures or leaks – if known;

(vi) Location of casings and if shorted;

(vii) Any in-service ruptures or leaks – including identified causes;

(viii) Data gathered through integrity assessments required under this section;

(ix) Close interval survey (CIS) survey results;

(x) Depth of cover surveys;

(xi) Corrosion protection (CP) rectifier readings;

(xii) CP test point survey readings and locations;

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

(xiv) Pipe coating surveys and cathodic protection surveys.

(xv) Results of examinations of exposed portions of buried pipelines (i.e., pipe and pipe coating condition, see § 195.569);

(xvi) Stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in-situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline;

(xvii) Aerial photography;

(xviii) Location of foreign line crossings;

(xix) Pipe exposures resulting from repairs and encroachments;

(xx) Seismicity of the area; and

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

(2) ~~(1)~~ Consider information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline;

(3) ~~(4)~~ Consider how a potential failure would affect high consequence areas, such as location of a water intake.

(4) Identify spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of

encroachment). Storing the information in a geographic information system (GIS), alone, is not sufficient. An operator must analyze for interrelationships among the data.

(h) * * *

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity, as required by this part. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats.

* * * * *

(2) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval ~~period~~ is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA in accordance with paragraph (m) of this section and provide an expected date when adequate information will become available.

* * * * *

(i) * * *

(2) * * *

(ix) Seismicity of the area.

* * * * *

(j) * * *

(2) *Verifying covered segments.* An operator must verify the risk factors used in identifying pipeline segments that could affect a high consequence area on at least an annual basis not to exceed 15 months (Appendix C provides additional guidance on factors that can influence whether a pipeline segment could affect a high consequence area). If a change in circumstance indicates that the prior consideration of a risk factor is no longer valid or that an operator should consider new risk factors, an operator must perform a new integrity analysis and evaluation to establish the endpoints of any previously identified covered segments. The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments (*see* paragraphs (b), (c), (d), and (e) of this section), information analyses (*see* paragraph (g) of this section), and decisions about remediation and preventive and mitigative actions (*see* paragraphs (h) and (i) of this section). An operator must complete the first annual verification under this paragraph no later than July 1, 2021.

* * * * *

(n) *Accommodation of instrumented internal inspection devices—*

(1) *Scope*. This paragraph does not apply to any pipeline facilities listed in § 195.120(b).

(2) *General*. An operator must ensure that each pipeline is modified to accommodate the passage of an instrumented internal inspection device by July 2, 2040.

(3) *Newly identified areas.* If a pipeline could affect a newly identified high consequence area (*see* paragraph (d)(2) of this section) after July 2, 2035 an operator must modify the pipeline to

accommodate the passage of an instrumented internal inspection device within 5 years of the date of identification or before performing the baseline assessment, whichever is sooner.

(4) *Lack of accommodation.* An operator may file a petition under § 190.9 of this chapter for a finding that the basic construction (i.e. length, diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device or that the operator determines it would abandon or shut-down a pipeline as a result of the cost to comply with the requirement of this section.

(5) *Emergencies.* An operator may file a petition under § 190.9 of this chapter for a finding that a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device as a result of an emergency. An operator must file such a petition within 30 days after discovering the emergency. If the petition is denied, the operator must modify the pipeline to allow the passage of an instrumented internal inspection device within 1 year after the date of the notice of the denial.

(o) *Referenced in list of changes, but not included in final language. Note on PHMSA web site regarding this paragraph reads as follows:*

"At 84 FR 52296, Oct. 1, 2019, §195.452 was amended by adding paragraph (o); however, the amendment could not be incorporated because the revised text was not provided."

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15. Add § 195.454 to Subpart F to read as follows:

§ 195.454 Integrity assessments for certain underwater hazardous liquid pipeline facilities located in high consequence areas.

Notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required under § 195.452, each operator of any underwater hazardous liquid pipeline facility located in a high consequence area that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water must ensure that:

(a) Pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months, and;

(b) Pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, are completed on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the pipeline facility is located.

Issued in Washington, DC, on September 17, 2019, under authority delegated in 49 CFR part 1.97.
Howard R. Elliott,
Administrator.
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