

ensure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline. The data integration and risk assessment requirements are in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d) considering the data on unique threats to a plastic pipeline. For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information, and decisions about remediation (§ 192.933) and 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.

The rule allows several assessment methods for a reassessment. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931. The methods allowed for reassessment are—

- Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow Section 6.2 of ASME/ANSI B31.8S in selecting the appropriate internal inspection tools for the covered segment.
- Pressure test conducted in accordance with Subpart J;
- Direct assessment to address threats of external corrosion and internal corrosion or stress corrosion cracking. 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 (external corrosion), 192.927 (internal corrosion) or 192.929 (stress corrosion cracking);
- 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.
- 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.

#### *Section 192.939 What Are the Required Reassessment Intervals?*

The required reassessment interval depends on the assessment method and the operating pressure of the pipeline. Some form of reassessment must be done at least every seven years.

For pipelines operating at or above 30% SMYS, the rule allows reassessment by—

1. Pressure test or internal inspection, or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

- Basing the intervals on the identified threats for the segment as listed in § 192.915 of this section and in Section 8, Tables 6 and 7 of ASME/ANSI B31.8S, and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.911; or
- Using the intervals for different stress levels of pipeline specified in Table 3, Section 5 of ASME/ANSI B31.8S.

2. External Corrosion Direct assessment. An operator that uses external corrosion direct assessment must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP0502–2002.

3. Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA must determine the reassessment interval by determining the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions, taking the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment and estimating the reassessment interval as half the time required for the largest defect to grow to a critical size. However, the reassessment interval cannot exceed those specified for direct assessment in Table 3, Section 5 of ASME/ANSI B31.8S.

If using one of these allowable methods, an operator establishes a reassessment interval that is greater than seven years, the operator must within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment done by confirmatory direct assessment must follow the requirements in § 192.931.

For pipelines operating below 30% SMYS the rule allows reassessment by—

1. Pressure test, internal inspection or other equivalent technology following the requirements for pipelines operating above 30% SMYS, except that the stress level would be adjusted to reflect the low operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low-stress reassessment in accordance with § 192.941.

2. External Corrosion Direct assessment following the requirements described for pipelines operating above 30% SMYS.

3. Internal Corrosion or SCC Direct Assessment following the requirements described for higher stress pipelines.

4. Confirmatory direct assessment at seven-year intervals in accordance with § 192.931, with reassessment by one of the other allowed methods (pressure test, internal inspection or direct assessment) by year 20 of the interval.

5. Low-stress assessment method at seven-year intervals in accordance with § 192.941 with reassessment by one of the other allowed methods (pressure test, internal inspection or direct assessment) by year 20 of the interval.

#### *Section 192.941 What Is a Low-Stress Reassessment?*

The rule provides for a low-stress reassessment for transmission pipelines that operate below 30% SMYS. This reassessment addresses the threats that are more common to these low-stress pipelines. The low-stress method only applies to a reassessment.

To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must—

- Perform an electrical survey (*i.e.*, indirect examination tool/method) at least every seven years on the covered segment.
- Use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

If an electrical survey is impractical on the covered segment an operator must instead

- Conduct leakage surveys at 4-month intervals; and
- Every 1½ years, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records,