

the periodic reassessment interval include:

- The stress level at which the pipeline operates;
- The growth rate of corrosion defects; and
- The repair criteria used in remediating defects discovered in previous assessments.

Figure 7–1 and Table 8–1 in ANSI/ASME B31.8S summarize the relevant factors for determining a reassessment interval. The corrosion rates reflected in these charts represent the high end of historically observed corrosion, but are not the highest rates that might be experienced under special conditions, such as the presence of microbiologically influenced corrosion (MIC). Table 8–1 relates the recommended reassessment interval in years to the stress level of the pipe (% SMYS), the type of assessment carried out, and the significance of defects left in the pipeline following mitigation or repair. For a typical pipe segment in a Class 3 Location, the stress level would be 50% SMYS. At this stress, if a pressure test were carried out at 1.39 times the maximum allowable operating pressure (MAOP), then the recommended reassessment interval would be 10 years. This same recommended reassessment interval would result if ILI were used and all defects were repaired that had a predicted failure pressure below 1.39 times the MAOP. The recommendations for reassessment intervals following use of direct assessment are closely related to the details of the excavation criteria used in examining indications. The intervals shown in (Table 8–1 in ASME B31.8S) are based on technical analysis of time-dependent failure mechanisms (e.g., external corrosion).

The recently-enacted pipeline safety law (HR 3609 signed into law Dec. 17, 2002) requires that reassessment be done at minimum intervals of seven-years. Thus, in our proposed rule, we have established a seven-year interval, but we also allow the operator to establish the intervals depending on the assessment method. Depending on the assessment method, the maximum interval an operator is allowed to establish could be longer than seven years. However, if the period is longer than seven years, the operator would have to conduct an interim reassessment by confirmatory direct assessment by the seventh year and then conduct the follow up reassessment in the year the operator has established. Thus, in the seven-year period an operator must either reassess a covered segment using the assessment method the operator has chosen, or if the operator has

established a longer interval, conduct a confirmatory direct assessment by the seventh year with a follow up reassessment in the year the operator sets. Our proposal takes into account the factors we have discussed above.

Monitor the Effectiveness of Pipeline Integrity Management Efforts

The seventh element of integrity management discussed in the June 27, 2001 FR notice, related to monitoring the effectiveness of pipeline integrity management activities. We used the following hypothesis in the notice:

- Measures can be developed to track actual integrity performance as well as to determine the value of assessment and repair activities.
- Application of integrity management technologies that exceed current regulations is cost effective because many companies made the decision to implement such programs.

Comments

INGAA suggested that RSPA/OPS should consider including the following performance measures:

- Number of miles of pipeline completed under IMP.
- *Repairs:*
 1. Number of immediate repairs completed as a result of the IMP inspection program; and
 2. Number of scheduled repairs completed as a result of the IMP inspection program.

- Number of leaks, failures and incidents (classified by cause).

AGA/APGA suggested that RSPA/OPS should work with stakeholders to develop performance measures immediately after promulgation of the integrity management rule. Additionally, in using these measures, RSPA/OPS must avoid inappropriate comparisons of performance among operators with vastly different systems.

NYGAS stated that performance measures should be properly used to monitor the effectiveness of integrity management efforts within individual companies, not to compare the performance among operators.

The Association of Texas Intrastate Natural Gas Pipelines commented that it would be useful for RSPA/OPS to establish performance measures that relate to each operator's integrity management plan, rather than requiring one-size-fits-all reporting requirements.

Enron commented that if RSPA/OPS were to increase the time for required submission of written pipeline incident reports by an additional sixty days, then there would be an opportunity to include better information on the evaluated cause of each incident.

The recently published standard ASME B31.8S discusses operator performance plans in Chapter 9. This discussion describes four measures that are required to be monitored by all operators using the standard. These measures are:

- Number of miles of pipeline inspected (assessed) versus program requirements;
- Number of immediate repairs completed as a result of the integrity management inspection program;
- Number of scheduled repairs completed as a result of the integrity management inspection program; and
- Number of leaks, failures and incidents (classified by cause).

RSPA/OPS is proposing to require operators to track and record these four overall performance measures, and make them electronically accessible (in real time) to RSPA/OPS for review. In addition, RSPA/OPS proposes to require operators to develop performance plans consistent with ASME B31.8S, and to define the extended set of measures that it will track. OPS will be able to review these measures during periodic field inspections. Appendix SP–A of ASME B31.8S tabulates suggested measures for each threat to which a pipeline might be subject.

Consideration of Impact on Gas Supply

The eighth consideration of integrity management discussed in the June 27, 2001 FR notice, related to the impact of the rule on gas supply. Performing an assessment test on gas transmission pipelines has the effect of restricting gas flow. Unless adequate time is allowed and the assessment process is carefully managed, this flow restriction can significantly impact gas supply and cost to customers.

Different assessment technologies have different restrictions on gas supply. In-line-inspection merely restricts flow for the relatively short time when the instrumented internal inspection device (pig) is in the pipe. However, preparing the pipe to make it able to be internally inspected (piggable), requires termination of the gas flow in the segment being tested while modifications are made. At present over 75% of gas transmission lines are not piggable or can be made piggable only with extensive modifications. Pressure testing requires termination of gas flow in the section being tested each time it is carried out. Direct assessment requires flow restriction (associated with lowering the pressure as a safety measure) while selected locations along the pipe are being excavated and directly examined.