

Response: Pipelines that operate at less than 20% SMYS are transmission pipelines if they meet the functional definition in § 192.3. The statute (49 U.S.C. 60109) does not except low-stress pipelines from the integrity management program requirements, including the requirement for reassessment at seven-year intervals. RSPA/OPS has revised the requirements, however, in recognition of the relatively low risk posed by pipelines operating at less than 30% SMYS. First, the rule allows two methods to define a high consequence area, so that an operator of a low-stress pipeline can rely on data it has already collected to identify the areas.

Second, the rule allows an alternative method of reassessment that focuses on the type of risk posed by these low-stress pipelines. RSPA/OPS agrees with AGA that these pipelines should be assessed initially and at the 20-year interval by the methods being used to assess higher stress pipelines, and has so required in the rule. During the 20-year interval, a low-stress line must be reassessed at seven year intervals by a low-stress reassessment, which is described below, or by confirmatory direct assessment. The rule incorporates confirmatory direct assessment (CDA) as a focused method of performing these interim assessments for pipelines operating at higher pressure. However, for low-stress pipelines, RSPA/OPS agrees that even CDA could be unduly burdensome. Therefore, the final rule adopts AGA's suggestion that electrical surveys are appropriate for conducting these interim low-stress reassessments between the assessments performed by methods being used to assess higher stress pipelines.

The rule allows operators of low-stress pipelines an option. They can perform CDA on seven-year intervals or they can conduct a low-stress reassessment that focuses on the types of threats these pipelines experience. A low-stress reassessment includes an electrical survey at least every seven years. For cathodically unprotected pipeline or areas where electrical surveys are impractical, increased leak surveys are required at a rate twice the current requirement. The additional measures also include provisions to protect against internal corrosion and third-party damage. RSPA/OPS has concluded that these measures provide appropriate interim protection for low-pressure pipelines, where the failure mode is predominantly leakage instead of rupture.

RSPA/OPS has also adopted AGA's suggestion that enhanced preventive and mitigative measures be required for

low-stress pipelines located in Class 3 and 4 areas. These measures protect against third-party damage, the type of threat most likely to result in a significant failure on these pipelines.

8. Remedial Actions—§ 192.931 (Formerly § 192.763(i))

There were numerous comments about the proposed remediation requirements particularly with respect to the proposed time periods for discovery, pressure reduction and remediation, and the proposed repair criteria in general and for dents.

The proposed requirements for scheduling remediation of anomalous conditions found during an assessment provided for immediate repair conditions, 180-day conditions, and conditions where remediation would take longer than 180 days. The 180-day conditions included certain dents. The proposed rule also referenced B31.8S as the basis for making repairs.

Industry commenters generally supported INGAA's suggestion that the repair criteria should be based on the industry standards, ASME/ANSI B31.8 and B31.8S. INGAA further suggested that the proposed 180-day time frame for evaluation and remediation of certain conditions should be changed to one year. INGAA explained that the 180-day limit would require remediation during winter months when the demand for gas is high. One year would allow operators one complete operating cycle in which to complete the work. Industry commenters supported this suggestion. INGAA also submitted recommended rule language that allowed time frames of one-year, more than one-year and monitored conditions, *i.e.*, conditions that would not have to be scheduled for remediation.

INGAA, and other industry commenters such as El Paso and Panhandle Eastern, contended that the requirement to remediate dents should be reconsidered and should be revised to distinguish between bottom-side and top-side dents. These commenters explained that constrained dents are not a threat. Depressions or dents in the bottom of the pipe are constrained; dents on the top of the pipe that are relatively unconstrained. Commenters recommended that the distinction be made by specifying remediation for dents between the 8 and 4 positions and on monitoring dents that do not need to be remediated.

The proposed remediation requirements provided that a pressure reduction could not exceed 365 days unless the operator took further remedial action to ensure the safety of

the pipeline. Many commenters, including the Gas Piping Technology Committee and Nicor Gas, argued that there is no basis for the proposed 365-day limit on pressure reduction and that operators should be allowed to use long-term pressure reduction if it provides equal or better safety. Public Service Electric and Gas Company asserted that the 365-day limit is not supported by any data analysis or risk assessment and should be removed. El Paso argued that pressure reductions should not be based on the pressure at the time of discovery but based possibly on either the MAOP or the highest pressure in the last 30 days. Sempra suggested we use technical information from a Pipeline Research Council International report that stated a pressure reduction in these circumstances may be determined using the highest pressure survived by the flaw since the time that it occurred.

The proposed discovery requirements were also a concern to many operators. The proposed rule provided that discovery occurs when an operator had adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline, and that discovery could occur no later than 180 days after conducting an integrity assessment unless the 180-day period is impracticable. Dominion contended the proposed language is confusing and suggested that discovery be tied to a time when the operator has adequate information concerning the conditions to determine that an indication requires a response as defined in ASME/ANSI B31.8S. INGAA and many other industry comments suggested that the proposed 180-day requirement associated with the discovery date be extended to one year to be consistent with ASME/ANSI B31.8S.

Response: We have revised the remediation requirements in the final rule. The rule provides that an operator be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. We thought this language more definite than being able to demonstrate a remediation will ensure the condition does not pose a threat to the long-term integrity of the pipeline. The final rule continues to provide that discovery occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Adequate information to make this determination would include information that the condition is one included in ASME/