

feeding the same customers, increases as the baseline period decreases.

- *Class location requirements.* The gas pipeline safety regulations have class location requirements that the liquid regulations do not. As population increases near a pipeline, the class location requirements require establishment of an additional margin of safety. To comply with class location requirements, gas transmission pipeline operators maintain data on the number of residences and other buildings located near their pipelines. Based on threshold levels of near-by dwellings and buildings, operators are required to constrain the maximum stress level in the pipeline to successively lower levels as the number of dwellings increases. When a class location changes to a higher class, an operator must reduce the stress level on the line either by reducing pressure, or in some cases, by replacing the pipe. If an operator replaces the pipe, an operator may use thicker walled or higher strength pipe to ensure that the capacity of the pipeline is not reduced.

The result is that, while gas pipelines in locations of potentially high consequence typically operate at stress levels of 40% SMYS (Class 4) or 50% SMYS (Class 3), corresponding liquid pipelines typically operate at 72% SMYS. A higher stress is typically associated with thinner walled piping or a smaller margin to failure for a given defect size. Therefore, time dependent threats such as external corrosion, which occur at a rate dependent on factors such as soil chemistry, coating integrity and cathodic protection effectiveness, have less wall thickness to penetrate before a critical defect depth is reached and the pipeline ruptures. The lower stress levels and thicker walls of gas pipelines imply that, other factors being equal, corrosion would take longer to penetrate to a critical depth.

These factors support a baseline assessment interval of ten years for operators using in-line-assessment or pressure testing, with at least 50% of the covered segments (the higher risk segments) being assessed within five years. However, for operators using direct assessment as the primary assessment technology, we are proposing a baseline assessment interval of seven years to account for the early state of development of these processes and to allow time to develop data on their validity. The highest risk half of the segments being assessed by direct assessment will, however, be assessed during the first four of these seven years. This proposal is consistent with The Pipeline Safety Improvement Act of 2002 (HR 3609, signed into law Dec. 17,

2002) which provides for a baseline assessment "not later than 10 years" after the law's enactment, with 50 % having to be assessed "not later than 5 years" after enactment. As noted earlier, RSPA/OPS is proposing to require operators choosing direct assessment technologies to undertake extra excavations and direct examinations during the period while validation is continuing.

Our proposal on the baseline assessment also allows for an assessment conducted five years before the law's enactment or date the final rule is effective, whichever is earlier, as a baseline assessment if it satisfies the specified assessment criteria. If an operator chooses this option, under our proposal, the operator would then have to begin complying with the requirements for reassessment of the segment.

#### *Identify and Implement Additional Preventive and Mitigative Measures*

The fifth element of integrity management discussed in the June 27, 2001, FR notice, related to identification and implementation of additional preventive and mitigative measures. We used the following hypotheses in the notice:

- Assuring a pipeline's integrity requires more than simple periodic inspection of the pipe. Most threats, including passive threats such as third party damage, require active management to prevent challenges to integrity. Therefore, active integrity management practices are necessary. Some operators already go beyond the current pipeline safety regulations by implementing integrity management practices such as ground displacement surveys, soil corrosivity analysis, gas sampling and sampling and analysis of liquid removed from pipelines at low points.

- Preventive and mitigative measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety. Such actions may include, damage prevention practices, better monitoring of cathodic protection, establishing shorter inspection intervals, and installing Remote Control Valves (RCVs) or Automatic Shut-Off Valves (ASVs) on pipeline segments. Some operators, particularly hydrogen pipeline operators, have voluntarily installed ASVs on their pipelines closer together than required as a mitigative measure.

#### *Comments*

INGAA described a general process used by operators to make decisions on adding risk control or mitigation

features beyond those required by regulation. The process involves establishment of a budget for additional safety enhancements and allocating that budget based on some structured form of risk assessment process, including feedback on potential risks from people in the field.

The conclusions of two INGAA-sponsored reports on the value of RCVs and ASVs include:

1. Neither RCVs nor ASVs will reduce fatalities or injuries to the public.
2. Neither control valve system will significantly reduce property damage.
3. RCVs and ASVs increase the likelihood of service disruption (RCVs in particular).
4. RCVs and ASVs can reduce the amount of product lost.
5. Costs for RCVs or ASVs outweigh measurable benefits.

According to INGAA, the only substantive benefit of RCVs and ASVs is that they result in faster valve closure following an incident.

Air Products and chemicals, an operator of 700 miles of pipeline for transporting industrial gas such as hydrogen, currently uses twenty-five excess flow valves along the 150 miles of pipe it operates in what it considers to be high consequence areas. These valves were added as a result of its risk analysis process.

GPTC noted that it expects ANSI to publish a technical report describing industry practices and ideas for managing integrity this Fall and requests that RSPA/OPS consider information in this document as part of its Rulemaking effort.

#### **Remote Control Valves (RCVs)**

In response to a Congressional mandate following the March 1994 gas transmission pipeline failure at Edison, NJ (Accountable Pipeline Safety and Partnership Act of 1996; codified at 49 U.S.C. 60102(j)), RSPA/OPS surveyed and assessed the effectiveness of remotely controlled valves (RCVs) on interstate natural gas pipelines. We examined the technical and economic feasibility of RCVs to rapidly shut down a gas transmission pipeline after a rupture.

RSPA/OPS conducted a public meeting in October 1997 to gather data on the technical and economic feasibility of installing RCVs. There was general agreement by the meeting participants, and in written comments following the meeting (contained in Docket No. RSPA-97-2879), that RCVs are technically feasible, but are not economically justifiable from a cost-benefit standpoint. This result is because most casualties and property