

way to validate the adequacy of the resulting mathematical relationship was to compare its predictions of potential impact radius with actual observed burn zone following historic gas pipeline ruptures. This comparison was carried out using the C-FER model which successfully predicted the radius of the burn zone surrounding ruptured gas pipelines.

*Incorporating Mathematical Formulation Describing the Heat Affected Zone Into the Rule*

We are proposing to require operators to calculate the potential impact radius within the HCA. This potential impact radius would be used to identify the areas within HCAs where the consequences of a rupture would be greatest. An operator would first focus any additional integrity measures on concentrations of people or hard to evacuate buildings or areas where people congregate within the impact radius, then on the rest of the HCA. Using more realistic criteria to define areas where an operator would focus additional integrity assurance measures will allow an operator to better allocate its resources toward areas that need the greatest protection. This approach will particularly benefit operators of small-diameter, low pressure pipelines, where the range of impact following a potential rupture would be small. This approach would also benefit the public because operators of very large diameter, very high pressure pipelines would have an increased impact radius to consider for evaluating where additional integrity assurance measures are required.

*Identify and Evaluate the Threats to Pipeline Integrity in Each Area of Potentially High Consequences*

The second element of integrity management discussed in the FR notice of June 27, 2001, involves identification of potential threats to the pipeline. In the notice we mentioned one approach suggested by industry in our past discussions was to divide potential threats to pipeline integrity into three categories: Time dependent (including internal corrosion, external corrosion, and stress corrosion cracking); static or resident (including defects introduced during fabrication of the pipe or construction of the pipeline); and time-independent (including third party damage and outside force damage; this threat category was called "random" in the FR notice). These three categories are adopted here primarily to focus resource allocation decisions on useful strategies to improve integrity (e.g., integrity management for the "time-independent" category clearly must

incorporate significant preventive measures), but do not eliminate the need for operators to consider all major threats to pipeline integrity. In addition, we said that human error can influence any or all of these threats and therefore must be considered as a potential contributing factor to each threat.

For the gas pipeline IMP proposed rule, we decided to propose that the operator make a threat-by-threat analysis of the entire pipeline. Such an analysis will require identification and evaluation of the significance of threats to pipeline integrity, which must necessarily involve the integration of numerous risk factors. Such risk factors include, but are not limited to, pipe characteristics (e.g., wall thickness, coating material and coating condition; pipe toughness; pipe strength; pipe fabrication technique; pipe elevation profile); internal and external environmental factors (e.g., soil moisture content and acidity, gas operating temperature and moisture content); operating and leak history (e.g., pipe failure history, past upset conditions that have introduced moisture into the gas); land use (e.g., active farming, commercial construction, residential construction); protection history (e.g., corrosion protection data, history of third party hits and near misses, effectiveness of local One Call systems); and the degree of certainty about the current condition of the pipeline (e.g., age of the pipe, completeness of integrity-related records, available inspection data).

The RSPA/OPS data on causes of gas transmission pipeline accidents (i.e., threats to the pipeline) show that between 1990 and 1999, there were total 777 reported accidents. The causes of these accidents are broken down as follows:

- 319 (41%) were due to outside force damage (30% third party, 11% earth quakes/floods, and other outside forces);
- 173 (22%) were due to corrosion (105 (14%) internal, 67 (9%) external);
- 119 (15%) were due to construction and material defects; and
- 166 (21%) were due to other causes.

The data indicates that the two greatest threats to a pipeline are from outside force damage (41%), and corrosion (22%). Our data also shows there are more failures from internal corrosion than from external corrosion. The internal corrosion is caused by moisture and acidity present in the gas transmission lines at low or near low points. The rupture of the gas transmission pipeline in Carlsbad, New Mexico resulted from internal corrosion.

Because corrosion can occur either internally or externally, it essential that gas pipeline operators consider both threats.

We believe this threat-by-threat analysis is necessary not only because it will require the operator to assemble and use a comprehensive set of risk factor data to identify the presence of potential threats, but also because it will support determination of the assessment approach or approaches needed to characterize the significance of these threats.

Our concept of integrity management also includes the following hypotheses: (1) Pipeline segments having threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk and (2) Pipelines that operate at a stress level less than 30% SMYS fail differently (i.e., leak rather than rupture) from those operating at higher stress, therefore, different integrity assurance techniques may be appropriate. We have discussed this issue elsewhere in this document and have requested comment.

*Comments on RSPA/OPS Hypotheses*

INGAA provided many comments on this hypothesis. The primary source of information referenced by INGAA was the technical reports prepared by their contractors during the eighteen month interaction among INGAA, RSPA/OPS and the states on technical issues, and the consensus standards currently in preparation. These reports are available in the Docket. Comments from INGAA included the following:

INGAA offered the opinion that laws should be enacted to support strong One-Call Programs. It also pointed out that seam cracking in pre-1970 ERW piping has been observed only in piping from certain manufacturers. Not all pre-1970 pipe has that problem.

INGAA also expressed the opinion that soil erosion is not a significant direct threat to pipeline integrity, however it may lead to increased importance of third-party damage when it results in shallow cover. In addition, it noted that some materials and construction techniques are more susceptible to damage from massive soil movement than others, and that this issue is treated more completely in ASME B31.8 S which was under development at the time of the comment, but has subsequently been issued.

On the subject of operator error, INGAA noted that performance measures are needed to evaluate the importance of this threat to pipeline integrity. Lessons learned from observed operator errors should then be