

(through the Class Location Requirements) on where the potential consequences of a gas pipeline accident may be most significant. In addition, since we were still collecting information and verifying the validity of assessment methods other than internal inspection and pressure testing, presenting the gas pipeline integrity management requirements as a single rule would delay review of the HCA definition. RSPA/OPS recently finalized the definition of HCAs (67 FR 50824; August 6, 2002).

In the current definition of HCAs (August 6, 2002), we noted four significant characteristics of gas pipelines ruptures and explosions that are relevant in defining HCAs. These same characteristics are useful here in the context of developing integrity management regulations. Those characteristics are: (1) The effects of a gas pipeline rupture and subsequent explosion are highly localized. The physical properties of natural gas dictate that it rises upward from a rupture as the gas expands into the air; (2) The zone of damage or heat affected zone following a rupture is related to the line's diameter and the pressure at which the pipeline is operated; (3) The size of the heat affected zone from pipeline ruptures where pipe diameter was less than 36 inches and operating pressures were at or below 1000 psig, was limited to a diameter of 660 feet; and (4) The heat affected zone for pipelines of 36 inches or greater, operating at pressures in excess of 1000 psig, can extend 1000 feet. Based on these findings, the HCA definition included language that would require operators of large diameter pipelines operating at high pressures to include areas within a 1000 foot radius from the pipeline. This proposed rule, referred to as the gas integrity management program (IMP) rule, will expand the current definition of HCAs (August 6, 2002), by adding consideration of people living at distances greater than 660 feet from large diameter high pressure pipelines. This expansion is based on the need to provide the same level of added protection to population groups, as the current HCAs provide to facilities that house people who are difficult to evacuate, people with impaired mobility, people who are confined, and areas where people congregate. This population group living at distances greater than 660 feet was inadvertently omitted from the definition when we proposed and later finalized the HCA definition.

The HCA definition for gas transmission lines was based on broad corridors that could potentially be

impacted from a pipeline rupture and explosion. However, additional calculations have to be used to determine the likely actual area that would be impacted. This proposed gas integrity management rule provides a method to analyze how a pipeline segment will impact an HCA if the segment fails. The definitions of a potential impact circle and potential impact zone that we are proposing, that are based on a mathematical equation, will essentially determine the likely actual area within an HCA that would be impacted. Whereas the HCA definition is based on broad corridors (*i.e.*, lateral distances perpendicular to pipeline) but not longitudinal distances (*i.e.*, axially along the pipeline), the potential impact circle and potential impact zones that we are proposing will provide longitudinal distances to define the actual area of impact in an HCA, and narrow the area to which the proposed assessment and repair requirements will apply.

This proposed rule also defines a Moderate Risk Area as an area located within a Class 3 or Class 4 location, but not within the potential impact zone. Whether a building located in a rural area, such as a rural church, which is currently included in the High Consequence Area definition, should be designated as a Moderate Risk Area requiring less frequent assessment or requiring enhanced preventive and mitigative measures is an issue for public comment that we discuss later in this document.

The process of identifying pipeline segments that are located in high consequence areas and moderate risk areas is described below under *Covered Segments*.

#### **Pipeline Safety Improvement Act of 2002**

On November 15, 2002, Congress passed H.R. 3609, the Pipeline Safety Improvement Act of 2002. The President signed the bill on December 17, 2002. Section 14 of H.R. 3609 contains requirements for integrity management programs for gas pipelines located in high consequence areas. The proposed rule which RSPA has been working on for some time is substantially in alignment with section 14 of H.R. 3609. However, there are differences. We have incorporated the requirements of section 14 into this proposed rule. These areas include the intervals for conducting baseline and reassessment testing, consideration of testing done prior to the final rule, the incorporation of issues raised by State and local authorities, the conduct of testing in an environmentally appropriate manner, a

requirement that the operator notify RSPA of changes to its program, and a means to make copies of operator records available to State interstate agents.

#### **Rule Synopsis**

The elements of an integrity management program are to consist of: (i) An identification of covered pipeline segments and the potential impact zone for each segment; (ii) a baseline assessment plan; (iii) an identification of threats to each covered pipeline segment, including risk assessments of each covered segment; (iv) a direct assessment plan, if direct assessment is to be used; (v) provisions for remediating conditions found; (vi) a process for continual evaluation and assessment; (vii) preventive and mitigative measures; (viii) a performance plan as outlined in ASME/ANSI B31.8S, Section 9; (ix) recordkeeping requirements; (x) a management of change process as outlined in ASME/ANSI B31.8S, Section 11; (xi) a quality assurance process as outlined in ASME/ANSI B31.8S, Section 12; (xiii) a communication plan based on ASME/ANSI B31.8S, Section 10, to include a process for addressing safety concerns raised by OPS, including safety concerns OPS raises on behalf of a State authority with which OPS has an interstate agent agreement and of local authorities; (xiv) a process for providing, by electronic or other means, a copy of the operator's integrity management program to a State authority with which OPS has an interstate agent agreement; and (xv) a process for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

#### **Covered Segments**

Operators must identify covered segments prior to performing assessments. A covered segment is any transmission pipeline segment. The approach involves six steps that rely on the definitions contained in section 192.761. Those six steps are: (1) Identify all high consequence areas for the pipeline using the HCA definition as expanded by this proposed rule; (2) calculate the Potential Impact Radius (PIR) for each covered segment in the pipeline; (3) determine the Threshold Radius associated with the PIR for each segment; (4) identify Potential Impact Circles for the pipeline; (5) identify the Potential Impact Zones (PIZ) for the pipeline, and based on that zone for covered segments located in Class 3 and Class 4 locations, identify the moderate