

covered segments of their pipelines that have similar characteristics to covered sections on which corrosion is found (§ 192.917(e)(5) and § 192.927(c)(3)(iii)). The rule further requires that operators who qualify for the performance-based option have a procedure for applying lessons learned from assessment of covered pipe segments to pipe segments not covered. (§ 192.913(b)(1)(iv).)

The rule does not require integrity assessment, but it does require evaluation of risk associated with non-covered segments and appropriate actions to address those risks. Such a requirement would divert resources away from pipeline segments that pose the most risk (*i.e.*, those located in HCAs) to those which pose lesser risks. ASME/ANSI B31.8S, the consensus standard on *Managing System Integrity of Gas Pipelines*, provides a method by which operators can perform these evaluations.

Although it is necessary to apply lessons learned on covered segments to non-covered segments of pipeline, it is equally appropriate that knowledge gained in segments of pipeline that cannot affect HCAs be used in the evaluation of covered segments. The rule requires this as part of an operator's data gathering and integration activities (§ 192.917(b)). The operators must, at a minimum, evaluate the set of data specified in ASME/ANSI B31.8S.

When RSPA/OPS proposed the integrity management program requirements for gas transmission pipelines, it had not considered plastic transmission pipelines. The statute does not allow an exemption for such pipelines. However, based on the information developed after issuance of the NPRM, we recognize that these pipelines typically operate at very low pressures and are not subject to corrosion. Internal inspection tools are not useful for evaluating the condition of these pipelines. Corrosion protection measures are not required because plastic does not corrode. Therefore, in the final rule we have recognized that these pipelines cannot be assessed by the methods allowed for metallic transmission pipelines. An operator of a plastic transmission pipeline will have to conduct, on a continual basis, a threat analysis to evaluate the threats unique to the integrity of plastic pipe. If the analysis shows that the pipeline is susceptible to failure from a cause other than third-party damage, the operator must conduct a baseline assessment by a method demonstrated to characterize the risks, and must apply additional preventive and mitigative measures as necessary.

A government/industry Plastic Pipe Database Committee (PPDC) has been formed to develop and maintain a voluntary plastic pipe data collection process to support the analysis of the frequency and causes of in-service plastic pipe material failures. The PPDC monitors failure experience to characterize any failure trends in older plastic pipe materials. Thorough analysis of data on plastic pipelines having similar fabrication, construction, and operational characteristics will alert operators of these pipelines to integrity threats other than third-party damage.

3. High Consequence Areas—§ 192.903 (Formerly § 192.761)

The definition of HCAs for gas transmission pipelines was set forth in a final rule on August 6, 2002. The definition included Class 3 and 4 locations, and "identified sites", *i.e.*, buildings housing people who have limited mobility or are difficult to evacuate and outside areas where there is sufficient evidence of people congregating. The rule listed ways for an operator to identify these sites, including visible marking, licensure or registration by a Federal, State, or local agency, knowledge of public safety officials, or a list or map maintained by or available from a Federal, State, or local agency.

The definition generated numerous comments. And, as discussed elsewhere in this document, industry trade associations filed a petition for reconsideration of the definition. At the public meetings following the issuance of the integrity management NPRM, meeting participants commented in great detail about problems with the definition. At the TPSSC meeting, members discussed the definition and issues raised in the petition for reconsideration.

Comments on the proposed definition of HCAs for gas transmission pipelines addressed the complexity of the definition and difficulty in identifying HCAs; additional areas to be included; the role of public officials in "identified sites;" numbers of people congregating in outside areas and in "identified site" buildings; C-FER model; Threshold Radius; system considerations; and calculation of Moderate Risk Areas, Potential Impact Circle (PIC), Potential Impact Radius (PIR), and Potential Impact Zone (PIZ). The comments on each of these topics are discussed below.

The Definition's Complexity and Difficulty in Identifying HCAs

The high consequence area definition included Class 3 and 4 areas because

these areas are currently defined in the gas pipeline safety regulations. The definition also included "identified sites" and a list of methods for identifying them. These sites included facilities with people who are confined, of limited mobility or would be difficult to evacuate, and outside areas and buildings where there is evidence that at least 20 or more people congregate on at least 50 days in any 12-month period.

In the NPRM for integrity management program, RSPA/OPS proposed to add another area to the definition—a circle of Threshold Radius 1,000 feet or larger that has a cluster of 20 or more buildings intended for human occupancy.

In their petition for reconsideration of the HCA definition, the petitioners argued that RSPA should clarify the definition, particularly with regard to "identified sites," because the definition is so broad and vague as to make compliance impractical. Comments at the post-NPRM public meetings also suggested that the definition needed to be clarified.

Many commenters noted the complexity of the proposed expanded definition and asked that it be simplified. Baltimore Gas and Electric (BG&E) asserted that the number of variables and data requirements related to the definition make it unworkable. BG&E explained that distribution system operators maintain data on population and buildings near their pipelines, but would have difficulty identifying facilities with persons who are confined or of limited mobility and areas where people congregate. The company recommended that the definition only reference verifiable criteria in determining areas to be covered under the integrity management requirements. Northeast Gas Association requested clarification on whether the proposed expanded definition only applied to large diameter, high pressure pipe.

Dominion supported the use of current Class designations to define HCAs because it believes smaller pipeline companies do not have access to sophisticated geographic information systems (GIS). The State of New York also supported the use of the current Class designations, supplemented by the use of the C-FER model to identify HCAs outside of Class 3 and 4 areas.

INGAA argued that the proposed addition to the HCA definition added complexity and additional practices that would not improve pipeline safety. INGAA proposed a bifurcated option, which would allow the operator some flexibility in determining its cumulative HCA sites. Under this proposal, an