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DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

49 CFR Part 192

[Docket No. PHMSA-2011-0023]

RIN 2137-AE72

Pipeline Safety: Safety of Gas Transmission Pipelines

ACTION: Advance Notice of Proposed Rulemaking (ANPRM).

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

SUMMARY: PHMSA is considering whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether integrity management (IM) requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA is considering concerning IM requirements is whether the definition of a high-consequence area (HCA) should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods. With respect to non-IM requirements, PHMSA is considering whether revised requirements are needed on new construction or existing pipelines concerning mainline valves, including valve spacing and installation of remotely operated or

automatically operated valves; whether requirements for corrosion control of steel pipelines should be strengthened; and whether new regulations are needed to govern the safety of gathering lines and underground gas storage facilities. Additional issues PHMSA is considering are addressed in the SUPPLEMENTARY INFORMATION Section under background.

DATES: Persons interested in submitting written comments on this ANPRM must do so by December 2, 2011. PHMSA will consider late filed comments as far as practicable.

FOR FURTHER INFORMATION CONTACT: Mike Israni, by telephone at 202-366-4571, by fax at 202-366-4566, or by mail at U.S. DOT, PHMSA, 1200 New Jersey Avenue, SE, PHP-1, Washington, DC 20590-0001.

ADDRESSES: You may submit comments identified by the docket number PHMSA-2011-0023 by any of the following methods:

- Web Site: http://www.regulations.gov. Follow the online instructions for submitting comments.
- Fax: 1-202-493-2251.
- Mail: Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12-140, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001 between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays.

Instructions: If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Note: Comments are posted without changes or edits to http://www.regulations.gov, including any personal information provided. There is a privacy statement published on http://www.regulations.gov. A glossary of terms used in this document can be found at the following website: http://primis.phmsa.dot.gov/comm/.

SUPPLEMENTARY INFORMATION:

I. Background

Congress has authorized Federal regulation of the transportation of gas by pipeline under the Commerce Clause of the U.S. Constitution. The authorization is codified in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*), a series of statutes that are administered by PHMSA. PHMSA promulgated comprehensive minimum safety standards for the transportation of gas by pipeline under the Pipeline Safety Regulations (PSR; 49 CFR Parts 190-199).

Congress established the current framework for regulating natural gas pipelines in the Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481, which has since been recodified at 49 U.S.C. 60101 *et seq*. That law delegated to DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. Congress has since enacted additional legislation that is currently codified in the Pipeline Safety Laws.

In 1992, Congress required regulations be issued to define the term "gathering line" and establish safety standards for certain "regulated gathering lines." In 1996, Congress directed that DOT conduct demonstration projects evaluating the application of risk management principles to pipeline safety regulations, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel.

In 2002, Congress required that DOT issue regulations requiring operators of gas transmission pipelines to conduct risk analyses and to implement IM programs under which pipeline segments in HCAs would be subject to a baseline assessment within ten years and re-assessments at least every seven years. PHMSA administers compliance with these statutes and has promulgated comprehensive safety standards and regulations for the transportation of natural gas by pipeline. That includes regulations for the:

- Design and construction of new pipeline systems or those that have been relocated, replaced, or otherwise changed (Subparts C and D of 49 CFR Part 192).
- Protection of steel pipelines from the adverse effects of internal and external corrosion (Subpart I of 49 CFR Part 192).
- Pressure tests of new pipelines (Subpart J of 49 CFR Part 192).
- Operation and maintenance of pipeline systems, including establishing programs for public awareness and damage prevention, and managing the operation of pipeline control rooms (Subparts L and M of 49 CFR Part 192).
- Qualification of pipeline personnel (Subpart N of 49 CFR Part 192).
- Management of the integrity of pipelines in HCAs (Subpart O of 49 CFR Part 192).

The IM requirements of Subpart O of 49 CFR Part 192 apply to areas called high consequence areas or HCA's. An integrity management program is a documented set of policies, processes, and procedures that are implemented to ensure the integrity of a pipeline. In accordance with pipeline safety regulations for gas transmission pipelines (Subpart O of 49CFR Part 192) an operator's integrity management program must include, at a minimum, the following elements:

a. An identification of all high consequence areas;
b. A baseline assessment plan;
c. An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment and to evaluate the merits of additional preventive and mitigative measures for each covered segment;
d. A direct assessment plan, if applicable;
e. Provisions for remediating conditions found during an integrity assessment;
f. A process for continual evaluation and assessment;
g. If applicable, a plan for confirmatory direct assessment meeting the requirement;
h. Provisions for adding preventive and mitigative measures to protect the high consequence area;
i. A performance plan that includes performance measures;
j. Record keeping provisions;
k. A management of change process;
l. A quality assurance process;
m. A communication plan that includes procedures for addressing safety concerns raised by PHMSA or a State or local pipeline safety authority;

n. Procedures for providing (when requested) a copy of the operator's risk analysis or integrity management program to PHMSA or a State or local pipeline safety authority; and
o. Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks;
p. A process for identification and assessment of newly-identified high consequence areas.

A high consequence area is a location that is specially defined in the pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA. The PSR provide gas transmission pipeline operators with two options by which to identify which segments of their pipelines are in HCAs: (1) reliance on class locations that historically have been part of the pipeline safety regulations for identifying pipelines in more-populated areas, or (2) determining segments for which a specified number of structures intended for human occupation or a so-called identified site (representing areas where people congregate) are located within the potential impact radius of a hypothetical pipeline rupture and subsequent explosion.

Other recent rulemaking have addressed different but related issues relative to pipeline safety. On October 18, 2010 (75 FR 63774) PHMSA published an ANPRM titled “Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines.” In that rulemaking , PHMSA is considering whether changes are needed to the regulations covering hazardous liquid onshore pipelines. In particular, PHMSA sought comment on whether it should extend regulation to certain pipelines currently exempt from regulation; whether other areas along a pipeline should either be identified for extra protection or be included as additional HCAs for IM protection; whether to establish and/or adopt standards and procedures for minimum leak detection requirements for all pipelines; whether to require the installation of emergency flow restricting devices (EFRDs) in certain areas; whether revised valve spacing requirements are needed on new construction or existing pipelines; whether repair timeframes should be specified for pipeline segments in areas outside the HCAs that are assessed as part of the IM; and whether to establish and/or adopt standards and procedures for improving the methods of preventing, detecting, assessing and remediating stress corrosion cracking (SCC) in hazardous liquid pipeline systems.

On December 4, 2009, PHMSA issued the Distribution Integrity Management Final Rule, which extends the pipeline integrity management principles that were established for hazardous liquid and natural gas transmission pipelines, to the local natural gas distribution pipeline systems. This regulation, which became effective in August of 2011, requires operators of local gas distribution pipelines to evaluate the risks on their pipeline systems, to determine their fitness for service, and to take action to address those risks. For older gas distribution systems, the appropriate mitigation measures could involve major pipe rehabilitation, repair, and replacement programs. At a minimum, these measures are needed to requalify those systems as being fit for service.

II. Advance Notice of Proposed Rulemaking

PHMSA believes that the IM requirements applicable to gas transmission pipelines contained in the Pipeline Safety Regulations (49 CFR Parts 190-199) have increased the level of safety associated with the transportation of gas in HCA's. Still, incidents with significant consequences continue to occur on gas transmission pipelines (e.g., incident in San Bruno, CA September 9, 2010). PHMSA has also identified concerns during inspections of gas transmission pipeline operator IM programs that indicate a potential need to clarify and enhance some requirements. PHMSA is now considering whether additional safety measures are necessary to increase the level of safety for those pipelines that are in non-HCA areas as well as whether the current IM requirements need to be revised and enhanced to assure that they continue to provide an adequate level of safety in HCAs.

Within this ANPRM, PHMSA is seeking public comment on 14 specific topic areas in two broad categories.

1. Should IM requirements be revised and strengthened to bring more pipeline mileage under IM requirements and to better assure safety of pipeline segments in HCAs? Specific topics include:

- Modifying the definition of an HCA.
- Strengthening the Integrity Management requirements in Part 192.
- Modifying repair criteria.
- Revising the requirements for collecting, validating, and integrating pipeline data.
- Making requirements related to the nature and application of risk models more prescriptive.

- Strengthening requirements for applying knowledge gained through the IM program.

- Strengthening requirements on the selection and use of assessment methods, including prescribing assessment methods for certain threats (such as manufacturing and construction defects, SCC, etc.) or in certain situations such as when certain knowledge is not available or data is missing.

2. Should non-IM requirements be strengthened or expanded to address other issues associated with pipeline system integrity? Specific topics include:

- Valve spacing and the need for remotely- or automatically-controlled valves.

- Corrosion control.

- Pipe with longitudinal weld seams with systemic integrity issues.

- Establishing requirements applicable to underground gas storage.

- Management of Change.

- Quality Management Systems (QMS).

- Exemptions applicable to[1] facilities installed prior to the regulations.

- Gathering lines.

Each topic is discussed in more detail in this document.

[1] As described below, these exemptions relate to allowable maximum operating pressure for pipelines that were in service before the initial gas pipeline safety regulations were published. These pipelines are commonly known as "grandfathered" pipelines.

A. Modifying the Definition of HCA

Part 192 has historically included requirements delineating pipeline segments by class location based on the population density near the pipeline. Class locations are based on the number of buildings intended for human occupancy that exist within a "class location unit," defined as an area extending 220 yards (100 meters) on either side of the centerline of any continuous one-mile (1.6 kilometers) length of pipeline. Class locations are defined in §192.5 as:

- Class 1 – 10 or fewer buildings intended for human occupancy within a class location unit.
- Class 2 – more than ten but less than 46 buildings intended for human occupancy.
- Class 3 – 46 or more buildings intended for human occupancy.
- Class 4 – any class location unit where buildings with four or more stories are prevalent.

Part 192 provides additional protection for higher class location areas, principally through provisions that require pipe in these higher class locations to operate at lower stress levels.

With the advent of IM requirements, PHMSA introduced a new mechanism in Part 192 to define pipeline segments to which additional requirements should apply based on the population at risk in the vicinity of the pipeline. HCAs are defined in § 192.903 using either of two methods. Operators are allowed to pick the method they use to identify their HCAs.

Method 1 builds on the traditional concept of class locations. Under this method, all pipeline segments in Class 3 and 4 locations are within an HCA. In addition, pipeline segments in Class 1 and 2 locations are within an HCA if an "identified site" is located within the "potential impact circle." Identified sites are defined as areas in which 20 or more persons congregate for a specified number of days each year or facilities occupied by persons who are confined, of impaired mobility, or would be difficult to evacuate.

Method 2 defines HCAs based solely on potential impact circles. A potential impact circle is an estimated zone in which the failure of a pipeline could have significant impact on people or property. The radius of the potential impact circle is calculated using a formula specified in the regulations that is based on the diameter and operating pressure of the pipeline.
A pipeline segment is identified as an HCA if the potential impact circle includes 20 or more buildings intended for human occupancy or an identified site, regardless of class location.

Some gas transmission pipeline operators do not collect data concerning the number of buildings within class location units along their pipeline, but rather design all of their pipelines as though they were in a Class 3 or 4 location. This approach is often used by operators of gas distribution companies that also operate small amounts of pipeline meeting Part 192's definition as transmission pipeline. Method 1 was included in the definition of an HCA in deference to these operators, allowing them to avoid the additional costs associated with collecting data on nearby buildings that they have not previously collected. Method 2 was presumed to identify pipeline segments where incidents could produce high consequences more accurately and is typically used by pipeline operators who have collected data on local structures to determine class locations.

PHMSA regulates approximately 297,000 miles of onshore gas transmission pipelines**.** Of these, approximately 30,300 miles (10.2%) are in Class 2 locations, approximately 33,500 miles (11.3%) are in Class 3 locations, and approximately 1600 miles (0.54%) are in Class 4 locations. Operators have identified approximately 19,000 miles (6.4%) of gas transmission pipeline to be within an HCA.

IM requirements in Subpart O of Part 192 specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate; through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so.

A gas transmission pipeline ruptured in San Bruno, California on September 9, 2010, resulting in eight deaths and considerable property damage. As a result of this event, public concern has been raised regarding whether safety requirements applicable to pipe in populated areas can be improved. PHMSA is thus considering expanding the definition of an HCA so that more miles of pipe are subject to IM requirements.

Questions

A.1. Should PHMSA revise the existing criteria for identifying HCAs to expand the miles of pipeline included in HCAs? If so, what amendments to the criteria should PHMSA consider (e.g., increasing the number of buildings intended for human occupancy in Method 2?) Have improvements in assessment technology during the past few years led to changes in the cost of assessing pipelines? Given that most non-HCA mileage is already subjected to in-line inspection

(ILI) does the contemplated expansion of HCAs represent any additional cost for conducting integrity assessments? If so, what are those costs? How would amendments to the current criteria impact state and local governments and other entities?

A.2. Should the HCA definition be revised so that all Class 3 and 4 locations are subject to the IM requirements? What has experience shown concerning the HCA mileage identified through present methods (e.g., number of HCA miles relative to system mileage or mileage in Class 3 and 4 locations)? Should the width used for determining class location for pipelines over 24 inches in diameter that operate above 1000 psig be increased? How many miles of HCA covered segments are Class 1, 2, 3, and 4? How many miles of Class 2, 3, and 4 pipe do operators have that are not within HCAs?

A.3. Of the 19,004 miles of pipe that are identified as being within an HCA, how many miles are in Class 1 or 2 locations?

A.4. Do existing criteria capture any HCAs that, based on risk, do not provide a substantial benefit for inclusion as an HCA? If so, what are those criteria? Should PHMSA amend the existing criteria in any way which could better focus the identification of an HCA based on risk while minimizing costs? If so, how? Would it be more beneficial to include more miles of pipeline under existing HCA IM procedures, or, to focus more intense safety measures on the highest risk, highest consequence areas or something else? If so, why?

A.5. In determining whether areas surrounding pipeline right-of-ways meet the HCA criteria as set forth in Part 192, is the potential impact radius sufficient to protect the public in the event of a gas pipeline leak or rupture? Are there ways that PHMSA can improve the process of right-of-ways HCA criteria determinations?

A.6. Some pipelines are located in right-of-ways also used, or paralleling those, for electric transmission lines serving sizable communities. Should HCA criteria be revised to capture such critical infrastructure that is potentially at risk from a pipeline incident?

A.7. What, if any, input and/or oversight should the general public and/or local communities provide in the identification of HCAs? If commenters believe that the public or local communities should provide input and/or oversight, how should PHMSA gather information and interface with these entities? If commenters believe that the public or local communities should provide input and/or oversight, what type of information should be provided and should it be voluntary to do so provide? If commenters believe that the public or local communities should provide input, what would be the burden entailed in providing provide this information? Should state and local governments be involved in the HCA identification and oversight process? If commenters believe that state and local governments be involved in the HCA identification and oversight process what would the nature of this involvement be?

A.8. Should PHMSA develop additional safety measures, including those similar to IM, for areas outside of HCAs? If so, what would they be? If so, what should the assessment schedule for non-HCAs be?

A.9. Should operators be required to submit to PHMSA geospatial information related to the identification of HCAs?

A10. Why has the number of HCA miles declined over the years?

A.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

B. Strengthening requirements to implement preventive and mitigative measures for pipeline segments in HCA

Section 192.935 requires gas transmission pipeline operators to take additional measures, beyond those already required by Part 192, to prevent a pipeline failure and to mitigate the consequences of a potential failure in an HCA. The additional measures to be taken are not specified. Rather, operators are required to base selection and implementation of these measures on the threats the operator has identified to each pipeline segment. Operators must use their comprehensive risk analyses to identify additional measures appropriate to the HCA. However, the rule establishes no objective criteria by which decisions concerning additional measures must be made, nor does it establish a standard by which such evaluations are to be performed. PHMSA is considering revising the IM requirement to add new requirements governing selection of additional preventive and mitigative measures.

The current regulations state that these additional measures might include: installing Automatic Shut-off Valves or Remote Control Valves; installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness; providing additional training to personnel on response procedures; conducting drills with local emergency responders, and implementing additional inspection and maintenance programs, but does not require implementation of any of these measures. Operators are also required to enhance their damage prevention programs and to take additional measures to protect HCA segments subject to the threat of outside force damage (non-excavation). Operators are required to install automatic or remotely-operable valves if their risk analysis concludes these would be an efficient means of adding protection to the HCA in the event of a gas release.

The requirements of § 192.935 apply only to pipeline segments in HCAs. As discussed above, only 6.4 percent of gas transmission pipeline mileage is currently classified as “located within HCAs.” Revising the criteria for identifying HCAs could, of course, increase the number of pipeline miles to which the requirements of § 192.935 apply. Still, PHMSA is considering whether these requirements, or other requirements for additional preventive and mitigative measures, should apply to pipelines outside of HCAs.

Questions

B.1. What practices do gas transmission pipeline operators now use to make decisions as to whether/which additional preventive and mitigative measures are to be implemented? Are these decisions guided by any industry or consensus standards? If so, what are those industry or consensus standards?

B.2. Have any additional preventive and mitigative measures been voluntarily implemented in response to the requirements of § 192.935? How prevalent are they? Do pipeline operators typically implement specific measures across all HCAs in their pipeline system, or do they target measures at individual HCAs? How many miles of HCA are afforded additional protection by each of the measures that have been implemented? To what extent do pipeline operators implement selected measures to protect additional pipeline mileage not in HCAs?

B.3. Are any additional prescriptive requirements needed to improve selection and implementation decisions? If so, what are they and why?

B.4. What measures, if any, should operators be required explicitly to implement? Should they apply to all HCAs, or is there some reasonable basis for tailoring explicit mandates to particular HCAs? Should additional preventative and mitigative measures include any or all of the following: additional line markers (line-of-sight); depth of cover surveys; close interval surveys for cathodic protection (CP) verification; coating surveys and recoating to help maintain CP current to pipe; additional right-of-way patrols; shorter ILI run intervals; additional gas quality monitoring, sampling, and in-line inspection tool runs; and improved standards for marking pipelines for operator construction and maintenance and one-calls? If so, why?

B.5. Should requirements for additional preventive and mitigative measures be established for pipeline segments not in HCAs? Should these requirements be the same as those for HCAs or should they be different? Should they apply to all pipeline segments not in HCAs or only to some? If not all, how should the pipeline segments to which new requirements apply be delineated?

B.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

C. Modifying repair criteria

The existing IM regulations establish criteria for the timely repair of injurious anomalies and defects discovered in the pipe (§ 192.933). These criteria apply to pipeline segments in an HCA, but not to segments outside an HCA. PHMSA is considering whether changes are needed to the IM rule related to the repair criteria to provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture. In addition, PHMSA is considering whether or not to establish repair criteria for pipeline segments located in areas outside an HCA, to provide greater assurance that defects on non-HCA pipeline segments are repaired in a timely manner.

In 2000 and 2002, PHMSA published final rules (65 FR 75378;12/1/2000 and 67 FR 2136; 1/16/2002) requiring IM Programs for hazardous liquid pipeline operators. In 2003, similar IM regulations were enacted for gas pipelines (68 FR 69778;12/15/2003). Some 43.9% of the nation's hazardous liquid pipelines (77,421 miles) and 6.5% of the natural gas transmission pipelines (19,004 miles) can potentially affect HCAs and thus receive the enhanced level of integrity assessment mandated by the IM rule. As a result of assessments, over the six-year period between 2004 and 2009, hazardous liquid operators have made 6,419 repairs of anomalies in HCAs that required immediate attention and remediated 25,027 other conditions on a scheduled basis. Between 2004 and 2009, gas pipeline operators have repaired 1,052 anomalies that required immediate attention and 2,239 other conditions. During this six-year period, hazardous liquid pipelines repair rate was 41.3 repairs per 100 HCA miles and gas transmission pipelines repair rate was 17.3 repairs per 100 HCA miles.

The gas IM regulations (§ 192.933) require "prompt action" to address all anomalous conditions discovered. More specifically, the IM regulation mandates "immediate" pressure reduction, pipeline shutdown, or repair of the following conditions: a predicted failure pressure less than or equal to 1.1 times (≤ 1.1) the established maximum allowable operating pressure (MAOP) at the location of the anomaly; a dent that has any indication of metal loss, cracking, or a stress riser; or any anomaly that in the judgment of the person designated by the operator to evaluate assessment results requires immediate action. Furthermore, operators must repair within one year, smooth dents at the top of the pipeline with a depth greater than six percent of the pipeline diameter and dents with a depth greater than two percent of the pipeline diameter that affect pipe curvature at a girth weld or at a longitudinal seam weld.

The method used to calculate the predicted failure pressure is prescribed in Part 192. However, the methods do not account for such factors as inaccurate ILI tool results, low tensile steel strength due to steel property variances, external loads such as caused by soil movement or settlement, or vehicle or farm equipment crossing the pipeline at grade. The IM repair criterion (predicted failure pressure ≤ 1.1 MAOP) includes a 10% margin between the predicted failure pressure and MAOP. PHMSA is considering if this is adequate to account for the above factors as well as operational factors that allow for the pipeline to operate up to 110% MAOP for brief periods during upset conditions (§§ 192.201 and 192.739).

In addition, regulations at §§ 192.103, 192.105, 192.107, and 192.111 require the usage of class location design factors. The design factor is 0.72 for Class 1 locations. The reciprocal (1.39) can be used to express a failure pressure ratio for sound pipe in a Class 1 location. The failure pressure ratio (FPR) of 1.39 indicates a safety factor over MAOP of 39 percent. This ratio is higher in other class locations (i.e., 1.67 in Class 2, 2.0 in Class 3, and 2.5 in Class 4). PHMSA is considering if class location design factors should be explicitly factored into repair criteria.

The assessments operators have been conducting on pipeline segments in HCAs have often extended to areas beyond the HCAs. PHMSA believes that many repairs have been made outside HCAs as in HCAs due to anomalies identified in these extended assessments, but gas transmission pipeline operators are not required to report these repairs so specific data are not available. Up to now, PHMSA has enforced the IM repair criteria as only applying to the anomalous conditions discovered in the HCAs. If, through the integrity assessment or information analysis, the operator discovers anomalous conditions in the areas outside the HCA, the pipeline safety regulations require operators to use the prompt remediation requirements in § 192.703 rather than the IM repair criteria. Though the remediation requirements in § 192.703 are more conservative than the IM repair criteria, this difference is off-set by the establishment of repair time frames, increased monitoring of any anomalous conditions, and other safety off-sets. The safety factor associated with the repair criteria in non-HCA is related to the class location design factor. For example, a Class 1 location has a 39% safety factor (1.67 in Class 2, 2.0 in Class 3 and 2.5 in Class 4). PHMSA is now considering whether the IM repair time frames should also be made to apply to the pipeline segments located outside HCAs when anomalous conditions in these areas are discovered through the integrity assessment. This would provide greater assurance that defects on non-HCA pipeline segments are repaired in a timely manner.

Questions

C.1. Should the immediate repair criterion of FPR $\leq$ 1.1 be revised to require repair at a higher threshold (i.e., additional safety margin to failure)? Should repair safety margins be the same as new construction standards? Should class location changes, where the class location has changed from Class 1 to 2, 2 to 3, or 3 to 4 without pipe replacement have repair criteria that are more stringent than other locations? Should there be a metal loss repair criterion that requires immediate or a specified time to repair regardless of its location (HCA and non-HCA)?

C.2. Should anomalous conditions in non-HCA pipeline segments qualify as repair conditions subject to the IM repair schedules? If so, which ones? What projected costs and benefits would result from this requirement?

C.3. Should PHMSA consider a risk tiering – where the conditions in the HCA areas would be addressed first, followed by the conditions in the non-HCA areas? How should PHMSA evaluate and measure risk in this context, and what risk factors should be considered?

C.4. What should be the repair schedules for anomalous conditions discovered in non-HCA pipeline segments through the integrity assessment or information analysis? Would a shortened repair schedule significantly reduce risk? Should repair schedules for anomalous conditions in HCAs be the same as or different from those in non-HCAs?

C.5. Have ILI tool capability advances resulted in a need to update the "dent with metal loss" repair criteria?

C.6. How do operators currently treat assessment tool uncertainties when comparing assessment results to repair criteria? Should PHMSA adopt explicit voluntary standards to account for the known accuracy of in-line inspection tools when comparing in-line inspection tool data with the repair criteria? Should PHMSA develop voluntary assessment standards or prescribe ILI assessment standards including wall loss detection threshold depth detection, probability of detection, and sizing accuracy standards that are consistent for all ILI vendors and operators? Should PHMSA prescribe methods for validation of ILI tool performance such as validation excavations, analysis of as-found versus as-predicted defect dimensions? Should PHMSA prescribe appropriate assessment methods for pipeline integrity threats?

C.7. Should PHMSA adopt standards for conducting in-line inspections using "smart pigs," the qualification of persons interpreting in-line inspection data, the review of ILI results including the integration of other data sources in interpreting ILI results, and/or the quality and accuracy of in-line inspection tool performance, to gain a greater level of assurance that injurious pipeline defects are discovered? Should these standards be voluntary or adopted as requirements?

C.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.

- The potential environmental impacts of modifying the existing regulatory requirements.

D. Improving requirements for collecting, validating, and integrating pipeline data

IM regulations require that gas transmission pipeline operators gather and integrate existing data and information concerning their entire pipeline that could be relevant to pipeline segments in HCAs (§192.917(b)). Operators are then required to use this information in a risk assessment of the covered segments at §192.917(c)) that must subsequently be used to determine whether additional preventive and mitigative measures are needed (§192.935) and to define the intervals at which IM reassessments must be performed (§192.939). Operators' risk analyses and the conclusions reached using them can only be as good as the information used to perform the analysis.

Preliminary results from the investigation of the September 9, 2010, pipeline rupture and explosion in San Bruno, CA, indicate that the pipeline operator's records concerning the pipe segments involved in the incident were erroneous. The errors affected basic information about the pipeline. For example, the records indicated that pipe in the area was 30-inch diameter seamless pipe, whereas pipe fragments recovered after the incident showed that seamed pipe was present. Thus, analyses performed using the information in the operator's records before the incident could not have led to accurate conclusions concerning risk, whether or not additional preventive and mitigative measures were needed, or what the allowable MAOP should be. PHMSA issued an Advisory Bulletin (76 FR 1504;January 10, 2011) on this issue. PHMSA is considering whether more prescriptive requirements for collecting, validating, integrating and reporting pipeline data is necessary.

Questions

D.1. What practices are now used to acquire, integrate and validate data (e.g., review of mill inspection reports, hydrostatic tests reports, pipe leaks and rupture reports) concerning pipelines? Are practices in place, such as excavations of the pipeline, to validate data?

D.2. Do operators typically collect data when the pipeline is exposed for maintenance or other reasons to validate information in their records? If discrepancies are found, are investigations conducted to determine the extent of record errors? Should these actions be required, especially for HCA segments?

D.3. Do operators try to verify data on pipe, pipe seam type, pipe mechanical and chemical properties, mill inspection reports, hydrostatic tests reports, coating type and condition, pipe leaks and ruptures, and operations and maintenance (O&M) records on a periodic basis? Are practices in place to validate data, such as excavation and *in situ* examinations of the pipeline? If so, what are these practices?

D.4. Should PHMSA make current requirements more prescriptive so operators will strengthen their collection and validation practices necessary to implement significantly improved data integration and risk assessment practices?

D.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

E. Making requirements related to the nature and application of risk models more prescriptive

As described above, current regulations require that gas transmission pipeline operators perform risk analyses of their covered segments and use these analyses to make certain decisions concerning actions to assure the integrity of their pipeline and to enhance protection against the consequences of potential incidents. The regulations do not prescribe the type of risk analysis nor impose any requirements regarding its breadth and scope.

PHMSA's experience in inspecting operator compliance with IM requirements has identified that most pipeline operators use a relative index-model approach to performing their risk assessments and that there is a wide range in scope and quality of the resulting analyses. It is not clear that all of the observed risk analyses can support robust decision making and management of the pipeline risk. PHMSA is considering making requirements related to the nature and application of risk models more prescriptive to improve the usefulness of these analyses in informing decisions to control risks from pipelines.

Questions

E.1. Should PHMSA either strengthen requirements on the functions risk models must perform or mandate use of a particular risk model for pipeline risk analyses? If so, how and which model?

E.2. It is PHMSA's understanding that existing risk models used by pipeline operators generally evaluate the relative risk of different segments of the operator's pipeline. PHMSA is seeking comment on whether or not that is an accurate understanding. Are relative index models sufficiently robust to support the decisions now required by the regulation (e.g., evaluation of candidate preventive and mitigative measures, and evaluation of interacting threats)?

E.3. How, if at all, are existing models used to inform executive management of existing risks?

E.4. Can existing risk models be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors? If so, how?

E.5. How can risk models currently used by pipeline operators be improved to assure usefulness for these purposes?

E.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenters' suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

F. Strengthening requirements for applying knowledge gained through the IM program

IM assessments provide information about the condition of the pipeline segments assessed. Identified anomalies that exceed criteria in § 192.933 must be remediated immediately (§ 192.933(d)(1)) or within one year (§ 192.933(d)(2)) or must be monitored on future assessments (§ 192.933(d)(3)). Operators are also expected to apply knowledge gained through these assessments to assure the integrity of their entire pipeline.

Section 192.917(e)(5) explicitly requires that operators must consider other portions of their pipeline if an assessment identifies corrosion requiring repair under the criteria of § 192.933. The operator must "evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics."

Section 192.917 also requires that operators conduct risk assessments that follow American Society of Mechanical Engineers/ American National Standards Institute (ASME/ANSI) B31.8S, Section 5, and use these analyses to prioritize segments for assessment, and to determine what preventive and mitigative measures are needed for segments in HCAs. Section 5.4 of ASME/ANSI B31.8S states that "risk assessment methods should be used in conjunction with knowledgeable, experienced personnel…that regularly review the data input, assumptions, and results of the risk assessments." That Section further states "An integral part of the risk assessment process is the incorporation of additional data elements or changes to facility data" and requires that operators "incorporate the risk assessment process into existing field reporting, engineering, and facility mapping processes" to facilitate such updates. Neither Part 192 nor ASME/ANSI B31.8S specifies a periodicity by which pipeline risk analyses must be reviewed and updated. This is considered a continuous ongoing process.

PHMSA is considering strengthening requirements related to operators' use of insights gained from implementation of its IM program.

Questions

F.1. What practices do operators use to comply with § 192.917(e)(5)?

F.2. How many times has a review of other portions of a pipeline in accordance with § 192.917(e)(5) resulted in investigation and/or repair of pipeline segments other than the location on which corrosion requiring repair was initially identified?

F.3. Do pipeline operators assure that their risk assessments are updated as additional knowledge is gained, including results of IM assessments? If so, how? How is data integration used and how often is it updated? Is data integration used on alignment maps and layered in such a way that technical reviews can identify integrity-related problems and threat interactions? How often should aerial photography and patrol information be updated for IM assessments? If the commenter proposes a time period for updating, what is the basis for this recommendation?

F.4. Should the regulations specify a maximum period in which pipeline risk assessments must be reviewed and validated as current and accurate? If so, why?

F.5. Are there any additional requirements PHMSA should consider to assure that knowledge gained through IM programs is appropriately applied to improve safety of pipeline systems?

F.6. What do operators require for data integration to improve the safety of pipeline systems in HCAs? What is needed for data integration into pipeline knowledge databases? Do operators include a robust database that includes: pipe diameter, wall thickness, grade, and seam type; pipe coating; girth weld coating; maximum operating pressure (MOP); HCAs; hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI surveys including high resolution – magnetic flux leakage (HR-MFL), HR-geometry/caliper tools; close interval surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current /direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; SCC excavations and findings; and pipe exposures from encroachments?

F.7. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

G. Strengthening requirements on the selection and use of assessment methods

The existing IM regulations require that baseline and periodic assessments of pipeline segments in an HCA be performed using one of four methods:

(1) In-line inspection;

(2) Pressure test per Subpart J;

(3) Direct assessment to address the threats of external and internal corrosion and SCC; or

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe.

Operators must notify PHMSA in advance if they plan to use "other technology." Operators must apply one or more methods, depending on the threats to which the covered segment is susceptible.

The three specified assessment methods provide different levels of understanding of pipeline integrity. In-line inspection, using modern technology, can provide information concerning small anomalies that can be evaluated and addressed, if needed, before they adversely affect pipeline integrity. In-line inspection, with appropriate selection of tools, is capable of detecting many types of anomalies including corrosion, dents and deformation, selective seam corrosion and other seam issues, and SCC. Pressure testing provides no information about the existence of anomalies that do not result in leaks or failures during the pressure test. Pressure tests are conducted at a pressure higher than MAOP to afford a safety margin between MAOP and a pressure at which failure might occur. Direct assessment can identify conditions (e.g., coating holidays, presence of water in the gas stream) that could lead to degradation and, through related excavations and direct examination, knowledge of whether such degradation is occurring in the locations examined. Direct assessment is not a satisfactory assessment technology to identify or characterize threats such as material or construction defects other than coating holidays, unless it is used with other non-destructive exam technologies that conduct a full pipe and weld body examination.

Standards for conducting pressure tests are specified in Subpart J of Part 192 and minimum pressures for these tests can be found at §§ 192.505, 192.507, 192.619, 192.620. Standards for external corrosion direct assessment (ECDA) are specified in §192.925 and in National

Association of Corrosion Engineers (NACE) NACE RP0502-2008 (incorporated by reference). Standards for internal corrosion direct assessment (ICDA) and SCC direct assessment (SCCDA) are in §§ 192.927 and 192.929 respectively, but in neither case is a consensus standard incorporated as is the case for ECDA. Standards for in-line inspection are not specified in the regulations.

PHMSA is considering strengthening the requirements for selection and use of assessment methods.

Questions

G.1. Have any anomalies been identified that require repair through various assessment methods (e.g., number of immediate and total repairs per mile resulting from ILI assessments, pressure tests, or direct assessments)?

G.2. Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions? Should restrictions on the use of assessment technologies other than ILI be strengthened? If so, in what respect? Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, longitudinal seam quality, SCC, or other attributes?

G.3. Direct assessment is not a valid method to use where there are pipe properties or other essential data gaps. How do operators decide whether their knowledge of pipeline characteristics and their confidence in that knowledge is adequate to allow the use of direct assessment?

G.4. How many miles of gas transmission pipeline have been modified to accommodate ILI inspection tools? Should PHMSA consider additional requirements to expand such modifications? If so, how should these requirements be structured?

G.5. What standards are used to conduct ILI assessments? Should these standards be incorporated by reference into the regulations? Should they be voluntary?

G.6. What standards are used to conduct ICDA and SCCDA assessments? Should these standards be incorporated into the regulations? If the commenter believes they should be incorporated into the regulations, why? What, if any, remediation, hydrostatic test or replacement standards should be incorporated into the regulations to address internal corrosion and SCC?

G.7. Does NACE SP0204-2008 (formerly RP0204), "Stress Corrosion Cracking Direct Assessment Methodology" address the full lifecycle concerns associated with SCC?

G.8. Are there statistics available on the extent to which the application of NACE SP0204-2008, or other standards, have affected the number of SCC indications operators have detected and remediated on their pipelines?

G.9. Should a one-time pressure test be required to address manufacturing and construction defects?

G.10. Have operators conducted quality audits of direct assessments to determine the effectiveness of direct assessment in identifying pipeline defects?

G.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

H. Valve spacing and the need for remotely or automatically controlled valves

Gas transmission pipelines are required to incorporate sectionalizing block valves. These valves can be used to isolate a section of the pipeline for maintenance or in response to an incident. Valves are required to be installed at closer intervals in areas where the population density near the pipeline is higher. Section 192.179 requires that block valves be located such that:

"(1) Each point on the pipeline in a Class 4 location must be within 2½ miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve."

These requirements apply to initial gas transmission pipeline construction. If population increases after a pipeline is placed in service, such that the class location changes, operators must reduce pressure, conduct pressure tests or verify the adequacy of prior pressure tests, or replace the pipeline to allow continued operation at the existing pressure. If operators replace the pipeline, then § 192.13(a)(1) would require that the new pipeline be "designed, installed, constructed, initially inspected, and initially tested in accordance with this part," including the requirements for valve spacing. If operators reduce pressure or verify that prior pressure tests are sufficient to justify continued operation without reducing pressure or replacing the pipeline, then no current regulation would require that new valves be installed to comply with the spacing requirements in § 192.179.

Sectionalizing block valves are not required to be remotely operable or to operate automatically in the event of an unexpected reduction in pressure (e.g., from a pipeline rupture). Congress has previously required PHMSA to "assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture" and to require use of such valves if they were shown technically and economically feasible.[2] The National Transportation Safety Board (NTSB) has also issued a number of recommendations concerning requirements for use of automatic or remotely operated mainline valves, including one following a 1994 pipeline rupture

[2] Accountable Pipeline Safety and Partnership Act of 1996, Public Law 104-304.

in Edison, NJ.[3] PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA) conducted the Congressionally-mandated evaluation and concluded that remotely and automatically controlled mainline valves are technically feasible but not, on a generic basis, economically feasible.[4] Nevertheless, IM regulations require that an operator must install an automatic or remotely operated valve if the operator determines, based on a risk analysis, that these would be an efficient means of adding protection to a HCA in the event of a gas release (§192.935(c)). In publishing this regulation, PHMSA acknowledged its prior conclusion that installation of these valves was not economically feasible but noted that this was a generic conclusion. PHMSA stated that it did not expect operators to re-perform the generic analyses but rather to "evaluate whether the generic conclusions are applicable to their HCA pipeline segments."[5]

The incident in San Bruno, CA on September 9, 2010, has raised public concern about the ability of pipeline operators to isolate sections of gas transmission pipelines in the event of an accident promptly and whether remotely or automatically operated valves should be required to assure this. PHMSA is considering changes to its requirements for sectionalizing block valves in response to these concerns.

Questions

[3] NTSB, "Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994," PB95-916501, NTSB/PAR-95/01, January 18, 1995.
[4] DOT, RSPA, "REMOTELY CONTROLLED VALVES ON INTERSTATE NATURAL GAS PIPELINES, (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996), September 1999.
[5] Federal Register, December 15, 2003, 68 FR 69798, column 3.

H.1. Are the spacing requirements for sectionalizing block valves in § 192.179 adequate? If not, why not and what should be the maximum or minimum separation distance? When class locations change as a result of population increases, should additional block valves be required to meet the new class location requirements? Should a more stringent minimum spacing of either remotely or automatically controlled valves be required between compressor stations? Under what conditions should block valves be remotely or automatically controlled? Should there be a limit on the maximum time required for an operator's maintenance crews to reach a block valve site if it is not a remotely or automatically controlled valve? What projected costs and benefits would result from a requirement for increased placement of block valves?

H.2. Should factors other than class location be considered in specifying required valve spacing?

H.3. Should the regulations be revised to require explicitly that new valves must be installed in the event of a class location change to meet the spacing requirements of § 192.179? What would be the costs and benefits associated with such a change?

H.4. Should the regulations require addition of valves to existing pipelines under conditions other than a change in class location?

H.5. What percentage of current sectionalizing block valves are remotely operable? What percentage operate automatically in the event of a significant pressure reduction?

H.6. Should PHMSA consider a requirement for all sectionalizing block valves to be capable of being controlled remotely?

H.7. Should PHMSA strengthen existing requirements by adding prescriptive decision criteria for operator evaluation of additional valves, remote closure, and/or valve automation? Should PHMSA set specific guidelines for valve locations in or around HCAs? If so, what should they be?

H.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

I. Corrosion control

Gas transmission pipelines are generally constructed of steel pipe, and corrosion is a threat of potential concern. Requirements for corrosion control of gas transmission pipelines are in Subpart I of Part 192. This Subpart includes requirements related to external corrosion, internal corrosion, and atmospheric corrosion. However, this Subpart does not include requirements for the specific threat of SCC.

Buried pipelines installed after July 31, 1971, are required to have a protective coating and CP unless the operator can demonstrate that the pipeline is not in a corrosive environment. Buried pipelines installed before that date must have CP if they have an effective coating or, if bare or with ineffective coating, if active corrosion is found to exist. Appendix D of Part 192 provides standards for the adequacy of CP and operators are required to conduct tests periodically to demonstrate that these standards are met.

These requirements have proven effective in minimizing the occurrence of incidents caused by gas transmission pipeline corrosion. Many of the provisions in Subpart I, however, are general. They provide, for example, that each pipeline under CP "have sufficient test stations or other contact points for electrical measurement to determine the adequacy of CP" (§ 192.469) rather than specifying the number or spacing of such test stations. Operators are required to take "prompt" remedial action to address problems with CP (§ 192.465(d)), but "prompt" is not defined. In addition, the regulations do not now include provisions addressing issues that experience has shown can be important to protecting pipelines from corrosion damage:

- Surveying post-construction for coating damage, using techniques such as direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Experience has shown that construction activities can damage coating and that identifying and remediating these damages can help protect against corrosion damage.

- Performing a post-construction close interval survey to assess the adequacy of CP and inform the location of CP test stations.
- Conducting periodic interference current surveys to detect and address electrical currents that could reduce the effectiveness of CP. Pipelines are often routed near, in parallel to, or in common right-of-ways with, electrical transmission lines that can induce such interference currents. Section 192.473 requires operators of pipelines subject to stray currents to have a program to minimize detrimental effects but does not require surveys, grounding mitigation, or provide any criteria for determining the adequacy of such programs.
- Requiring periodic use of an In-line Inspection Tool or sampling of accumulated liquids to assure that internal corrosion is not occurring.

PHMSA is considering revising Subpart I to address these areas and to improve the specificity of existing requirements.

Corrosion control regulations applicable to gas transmission pipelines include no requirements relative to SCC. SCC is cracking induced from the combined influence of tensile stress and a corrosive medium. SCC has been a contributing factor in numerous pipeline failures on hazardous liquids pipelines including a 2003 failure on a Kinder Morgan pipeline in Arizona, a 2004 failure on an Explorer Pipeline Company pipeline in Oklahoma, a 2005 failure on an Enterprise Products Operating line in Missouri, and a 2008 failure on an Oneok Natural Gas Liquids Pipeline in Iowa. More effective methods of preventing, detecting, assessing and remediating SCC in pipelines are important to making further reductions in pipeline failures.

PHMSA is seeking to improve understanding and mitigation of SCC threat. To this end, PHMSA is considering whether to establish and/or adopt standards and procedures, through a rulemaking proceeding, for improving the methods of preventing, detecting, assessing and remediating SCC. PHMSA is considering additional requirements to perform periodic coating surveys at compressor discharges and other high-temperature areas potentially susceptible to SCC.

PHMSA has taken numerous steps over many years to improve the understanding and mitigation of SCC in pipelines. These have included public workshops and studies on SCC. Initiatives taken, sponsored and/or supported by PHMSA designed to enhance understanding of SCC include:

- 1999 and 2004 SCC Studies– Two comprehensive studies on SCC were conducted for PHMSA's predecessor agency. First, "Stress Corrosion Cracking Study," Report No. DTRS56, prepared by General Physics Corporation in May 1999. Second, "Stress Corrosion Cracking Study," Report No. DTRS56-02-D-70036, submitted by Michael Baker Jr., Inc., in September 2004. These studies sought to improve understanding of SCC and to identify practical methods to prevent, detect and address SCC as well as provide a framework for potential future research. The first report noted that SCC accounted for only 1.5 percent of gas transmission pipeline incidents in the U.S., but 17 percent of incidents in Canada. The report concluded this disparity is not due to some inherent difference in U.S. and Canadian pipelines, but rather, due to the far greater occurrence of third party damage incidents in the U.S. The 2004 study is available at http://primis.phmsa.dot.gov/meetings/DocHome.mtg?doc=1

- Gas Transmission IM Rule – The gas transmission IM rule (68 FR 69778; December 15, 2003) requires operators to consider at least the potential threats listed in Section 2 of ASME/ANSI B31.8S, which includes SCC. The rule also specifies requirements for use of SCC direct assessment as a method of assessing gas transmission pipelines susceptible to this threat, which also require the use of criteria in ASME/ANSI B31.8S. The standard, however, addresses only high-pH SCC. Experience has shown that SCC occurring at near-neutral conditions is also a potential threat to gas transmission pipelines.

- 2003 Advisory Bulletin– In response to three SCC-driven failures of hazardous liquid pipelines in the U.S. in 2003 and other SCC incidents around the world, PHMSA issued an Advisory Bulletin, "Stress Corrosion Cracking Threats to Gas and Hazardous Liquid Pipelines" (68 FR 58166; October 8, 2003), urging all pipeline owners and operators to consider SCC as a possible safety risk on their pipeline systems and to include SCC assessment and remediation in their IM plans, for those systems subject to IM rules. For systems not subject to the IM rules, the bulletin urged owners and operators to assess the impact of SCC on pipeline integrity and to plan integrity verification activities accordingly.

- 2003 Public Workshop– PHMSA sponsored a public workshop on SCC on December 3, 2003, in Houston, Texas. Numerous PHMSA representatives, state officials, industry, consultants and officials from the National Energy Board of Canada attended and shared their respective experiences with SCC. The workshop also served as a forum for identifying issues for consideration in the 2004 Baker SCC study.

- 2005 Rulemaking– PHMSA issued rules that covered direct assessment, a process of managing the effects of external corrosion, internal corrosion or SCC on pipelines made primarily of steel or iron. "Standards for Direct Assessment of Gas and Hazardous Liquid Pipelines" (70 FR 61571; October 25, 2005).

Questions

Existing Standards

I.1. Should PHMSA revise Subpart I to provide additional specificity to requirements that are now presented in general terms, as described above? If so, which sections should be revised? What standards exist from which to draw more specific requirements?

I.2. Should PHMSA prescribe additional requirements for post-construction surveys for coating damage or to determine the adequacy of CP? If so, what factors should be addressed (e.g., pipeline operating temperatures, coating types, etc.)?

I.3. Should PHMSA require periodic interference current surveys? If so, to which pipelines should this requirement apply and what acceptance criteria should be used?

I.4. Should PHMSA require additional measures to prevent internal corrosion in gas transmission pipelines? If so, what measures should be required?

I.5. Should PHMSA prescribe practices or standards that address prevention, detection, assessment, and remediation of SCC on gas transmission pipeline systems? Should PHMSA require additional surveys or shorter IM survey internals based upon the pipeline operating temperatures and coating types?

I.6. Does the NACE SP0204-2008 (formerly RP0204) Standard "Stress Corrosion Cracking Direct Assessment Methodology" address the full lifecycle concerns associated with SCC? Should PHMSA consider this, or any other standards to govern the SCC assessment and remediation procedures? Do these standards vary significantly from existing practices associated with SCC assessments?

I.7. Are there statistics available on the extent to which the application of the NACE Standard, or other standards, have affected the number of SCC indications operators have detected on their pipelines and the number of SCC-related pipeline failures? Are statistics available that identify the number of SCC occurrences that have been discovered at locations that meet the screening criteria in the NACE standard and at locations that do not meet the screening criteria?

I.8. If new standards were to be developed for SCC, what key issues should they address? Should they be voluntary?

I.9. Does the definition of corrosive gas need to clarify that other constituents of a gas stream (e.g., water, carbon dioxide, sulfur and hydrogen sulfide) could make the gas stream corrosive? If so, why does it need to be clarified?

I.10. Should PHMSA prescribe for HCAs and non-HCAs external corrosion control survey timing intervals for close interval surveys that are used to determine the effectiveness of CP?

I.11. Should PHMSA prescribe for HCAs and non-HCAs corrosion control measures with clearly defined conditions and appropriate mitigation efforts? If so, why?

Existing Industry Practices

PHMSA is interested in the extent to which operators have implemented Canadian Energy Pipeline Association (CEPA) SCC, Recommended Practices 2nd Edition, 2007, and what the results have been.

I.12. Are there statistics available on the extent to which gas transmission pipeline operators apply the CEPA practices?

I.13.Are there statistics available that compare the number of SCC indications detected and SCC-related failures between operators applying the CEPA practices and those applying other SCC standards or practices?

I.14. Do the CEPA practices address the full lifecycle concerns associated with SCC? If not, which are not addressed?

I.15. Are there additional industry practices that address SCC?

The Effectiveness of SCC Detection Tools and Methods.

I.16. Are there statistics available on the extent to which various tools and methods can accurately and reliably detect and determine the severity of SCC?

I.17. Are tools or methods available to detect accurately and reliably the severity of SCC when it is associated with longitudinal pipe seams?

I.18. Should PHMSA require that operators perform a critical analysis of all factors that influence SCC to determine if SCC is a credible threat for each pipeline segment? If so, why? What experience-based indications have proven reliable in determining whether SCC could be present?

I.19. Should PHMSA require an integrity assessment using methods capable of detecting SCC whenever a credible threat of SCC is identified?

I.20. Should PHMSA require a periodic analysis of the effectiveness of operator corrosion management programs, which integrates information about CP, coating anomalies, in-line inspection data, corrosion coupon data, corrosion inhibitor usage, analysis of corrosion products, environmental and soil data, and any other pertinent information related to corrosion management? Should PHMSA require that operators periodically submit corrosion management performance metric data?

I.21. Are any further actions needed to address corrosion issues?

I.22. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
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- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

J. Pipe manufactured using longitudinal weld seams

Most gas transmission pipelines are constructed of steel pipe. The steel pipe is formed into pipe from steel plate, coil, or billet. The natural gas pipeline infrastructure in the United States is comprised of approximately 322,000 miles of transmission pipeline. Approximately 182,000 (56%) miles of gas transmission pipelines were built prior to 1970 and approximately 140,000 miles (44%) were built after 1970.

Pipelines built since the regulations (49 CFR Part 192) were implemented in early 1971 have been required to be:

- Pressure tested after construction and prior to being placed into gas service in accordance with Subpart J, and
- Manufactured in accordance with a referenced standard (most gas transmission pipe has been manufactured in accordance with American Petroleum Institute (API) API Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) referenced in 49 CFR Part 192).

Many gas transmission pipelines built from the 1940's through 1970 were manufactured in accordance with API 5L, but may not have been pressure tested similar to a Subpart J pressure test. These pipelines built prior to 1971were allowed by § 192.619 (a) to operate to an MAOP based on the highest five-year operating pressure prior to July 1, 1970, in lieu of a pressure test. (See section N, below, for a discussion of these exemptions.) Some of these old processes created pipe with variable characteristics throughout the longitudinal weld or pipe body.

Starting in the late-1960's, many pipe seam types used for the pre-1970's pipe have been discontinued as new modern steel making and pipe rolling practices were implemented. New steel and pipe manufacturing technology has led to new processes, the modification or improvement of some processes, and the abandonment of others. Many pipe manufacturing processes that produced pipe with longitudinal seam deficiencies have been discontinued such as low frequency electric resistance welded (LF-ERW), direct current electric resistance welded (DC-ERW), flash welded, furnace butt welded, and lap welded pipe.

As a result of 12 hazardous liquid pipeline failures that occurred during 1986 and 1987 involving pre-1970 ERW pipe, PHMSA issued an Alert Notice (ALN-88-01). Subsequent to the notice, one additional failure on a gas transmission pipeline, and eight additional failures on hazardous liquid pipelines, resulted in another Alert Notice (ALN-89-01. The notices identified that some failures appeared to be due to selective seam corrosion, but that other failures appeared to have resulted from flat growth of manufacturing defects in the ERW seam. In these notices, PHMSA advised all gas transmission and hazardous liquid pipeline operators with pre-1970 ERW pipe to:

- Consider hydrostatic testing on all hazardous liquid pipelines that have not been hydrostatically tested to 125% of the maximum allowable pressure, or alternatively reduce the operating pressure 20%;
- Avoid increasing a pipeline's long-standing operating pressure;
- Assure the effectiveness of the CP system. Consider the use of close interval pipe-to-soil surveys after evaluating the pipe coating and corrosion/CP history; and
- In the event of an ERW seam failure, conduct metallurgical examinations in order to determine the probable condition of the remainder of the ERW seams in the pipeline.

The rule for gas transmission pipeline IM prescribed the following specific requirements, for pipe in HCAs, consistent with the recommendations in ALN-89-01:

- Avoiding increasing a pipeline's long-standing operating pressure,
- If a pipeline's long-standing operating pressure is exceeded, or if stresses leading to cyclic fatigue increases, conduct an integrity assessment capable of detecting manufacturing and construction defects, including seam defects,
- Conduct an evaluation to determine if the pipeline is susceptible to manufacturing and construction defects, including seam defects. The evaluation must consider both covered

segments and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

In 2003, PHMSA also commissioned a study[6] of low frequency ERW and lap welded longitudinal seam issues. The study was conducted my Michael Baker, Inc., in collaboration with Kiefner and Associates, Inc., and CorrMet Engineering Services, PC. The study provided suggested guidelines that can be used to create policy for longitudinal seam testing.

Since 2002, there have been at least 22 reportable incidents on gas transmission pipeline which manufacturing or seam defects were contributing factors. Due to recent high consequence incidents caused by longitudinal seam failures, including the 2009 failure in Palm City, Florida and the 2010 failure in San Bruno, California, PHMSA is considering additional IM and pressure testing requirements for pipe manufactured using longitudinal seam welding techniques that have not had a Subpart J pressure test.

Questions

J.1. Should all pipelines that have not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), be required to be pressure tested in accordance with the present regulations? If not, should certain types of pipe with a pipeline operating history that has shown to be susceptible to systemic integrity issues be required to be pressure tested in accordance with the present regulations (e.g., low-frequency electric resistance

[6] *TTO Number 5, IM Delivery Order DTRS56-02-D-70036, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation,* FINAL REPORT, Revision 3, April 2004, available online at: http://primis.phmsa.dot.gov/iim/docstr/TTO5_LowFrequencyERW_FinalReport_Rev3_April2004.pdf .

welded (LF-ERW), direct current electric resistance welded (DC-ERW), lap-welded, electric flash welded (EFW), furnace butt welded, submerged arc welded, or other longitudinal seams)? If so, why?

J. 2. Are alternative minimum test pressures (other than those specified in Subpart J) appropriate, and why?

J.3. Can ILI be used to find seam integrity issues? If so, what ILI technology should be used and what inspection and acceptance criteria should be applied?

J.4. Are other technologies available that can consistently be used to reliably find and remediate seam integrity issues?

J.5 Should additional pressure test requirements be applied to all pipelines, or only pipelines in HCAs, or only pipelines in Class 2, 3, or 4 location areas?

J6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.

- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

K. Establishing requirements applicable to underground gas storage

Demand for natural gas fluctuates seasonally and sometimes based on other factors. Gas transmission pipeline operators use underground storage facilities as a means of accommodating these fluctuations. Gas is injected into storage during periods of low demand and is withdrawn for delivery to customers when demand is high. Underground storage facilities include caverns, many in salt formations, and related wells and piping to inject and remove gas. Underground storage caverns and injection/withdrawal piping are not currently regulated under Part 192. Pipelines that transport gas within a storage field are defined at § 192.3 as transmission pipelines and are regulated in the same manner as other transmission pipelines.

NTSB conducted an investigation subsequent to an accident involving uncontrolled release of highly volatile liquids from a salt dome storage cavern in Brenham, Texas in 1992 and recommended that DOT develop safety requirements for underground storage of highly volatile liquids and natural gas. RSPA initiated a rulemaking proceeding as a result of this recommendation. Following a period of study, RSPA concluded that Federal regulation of underground gas storage was not necessary and terminated that rulemaking. RSPA described this action in an Advisory Bulletin published in the Federal Register on July 10, 1997 (ADB-97-04, 62 FR 37118).

RSPA noted that most persons who spoke at a public meeting held as part of the rulemaking proceeding favored industry safety practices and state regulation to address safety of underground storage. RSPA commissioned a report that found that about 85 percent of surveyed storage facilities were under state regulation, to at least some degree. RSPA also noted that it had worked with the Interstate Oil and Gas Compact Commission (IOGCC) to develop standards for underground storage, which were published in a report titled: "Natural Gas Storage in Salt Caverns – A Guide for State Regulators" (IOGCC Guide). RSPA also noted that the API had published two sets of guidelines for underground storage of liquid hydrocarbons: API RP 1114, "Design of Solution-Mined Underground Storage Facilities," June 1994, and API RP 1115, "Operation of Solution-Mined Underground Storage Facilities," September 1994. RSPA encouraged operators of underground storage facilities and state regulators to use these resources in their safety programs.

A significant incident involving an underground gas storage facility occurred in 2001 near Hutchinson, KS. An uncontrolled release from an underground gas storage facility resulted in explosions and fires. Two people were killed. Many residents were evacuated from their homes. Some were not able to return for four months.

The Kansas Corporation Commission initiated enforcement action against the operator of the Hutchinson storage field as a result of safety violations associated with the accident. As part of this enforcement proceeding, it was concluded that the storage field was an interstate gas pipeline facility. Federal statutes provide that "[a] State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation" (49 USC §60104). There were, and remain, no Federal safety standards against which enforcement could be taken. The enforcement proceeding was therefore terminated.

PHMSA is considering establishing requirements within Part 192 applicable to underground gas storage to help assure safety of underground storage and to provide a firm basis for safety regulation. PHMSA notes that the IOGCC Guide is no longer available on the IOGCC web site. The API documents were both updated in July, 2007 (the latter redesignated as API 1115).

Questions

K.1 Should PHMSA develop Federal standards governing the safety of underground gas storage facilities? If so, should they be voluntary? If so, what portions of the facilities should be addressed in these standards?

K.2 What current standards exist governing safety of these facilities? What standards are presently used for conducting casing, tubing, isolation packer, and wellbore communication and wellhead equipment integrity tests for down-hole inspection intervals? What are the repair and abandonment standards for casings, tubing, and wellhead equipment when communication is found or integrity is compromised?

K.3. What standards are used to monitor external and internal corrosion?

K.4. What standards are used for welding, pressure testing, and design safety factors of casing and tubing including cementing and casing and casing cement integrity tests?

K.5. Should wellhead values have emergency shutdowns both primary and secondary? Should there be integrity and O&M intervals for key safety and CP systems?

K.6. What standards are used for emergency shutdowns, emergency shutdown stations, gas monitors, local emergency response communications, public communications, and O&M Procedures?

K.7. Does the current lack of Federal standards and preemption provisions in Federal law preclude effective regulation of underground storage facilities by States?

K.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

L. Management of change

Experience has shown that changes to physical configuration or operational practices often cause problems in the pipeline and other industries. Operation of a pipeline over an extended period without change tends to “shake out” minor issues and lead to their resolution. Ineffectively managed changes to pipeline systems (e.g., pipeline equipment, computer equipment or software used to monitor and control the pipeline) or to practices used to construct, operate, and maintain those systems can lead to difficulties. Changes can introduce unintended consequences because the change was not well thought out or was implemented in a manner not consistent with its design or planning. Changes in procedures require people to perform new or different actions, and failure to train them properly and in a timely manner can result in unexpected consequences. The result can be a situation in which risk or the likelihood of an accident is increased. A recently completed but poorly-designed modification to the pipeline system was a factor contributing to the Olympic Pipeline accident in Bellingham, Washington.

PHMSA pipeline safety regulations do not now address management process subjects such as management of change. PHMSA is considering adding requirements in this area to provide a greater degree of control over this element of pipeline risk.

Questions

L.1. Are there standards used by the pipeline industry to guide management processes including management of change? Do standards governing the management of change process include requirements for IM procedures, O&M manuals, facility drawings, emergency response plans and procedures, and documents required to be maintained for the life of the pipeline?

L.2. Are standards used in other industries (e.g., Occupational Safety and Health Administration standards at 29 CFR 1910.119) appropriate for use in the pipeline industry?

L.3. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

M. Quality Management Systems (QMS)

International Standards Organization (ISO) standard ISO 8402-1986 defines quality as "the totality of features and characteristics of a product or service that bears its ability to satisfy stated or implied needs."

Quality management includes the activities and processes that an organization uses to achieve quality. These include formulating policy, setting objectives, planning, quality control, quality assurance, performance monitoring, and quality improvement.

Achieving quality is critical to gas transmission pipeline design, construction, and operations. PHMSA recognizes that pipeline operators strive to achieve quality, but our experience has shown varying degrees of success in accomplishing this objective among pipeline operators. PHMSA believes that an ordered and structured approach to quality management can help pipeline operators achieve a more consistent state of quality and thus improve pipeline safety.

PHMSA's pipeline safety regulations do not now address process management issues such as QMS. Section 192.328 requires a quality assurance plan for construction of pipelines intended to operate at alternative MAOP, but there is no similar requirement applicable to other pipelines. Quality assurance is generally considered to be an element of quality management. PHMSA is considering whether and how to impose requirements related to QMS, especially their design and application to control equipment and materials used in new construction (e.g., quality verification of materials used in construction and replacement, post-installation quality verification), and to control the work product of contractors used to construct, operate, and maintain the pipeline system (e.g., contractor qualifications, verification of the quality of contractor work products).

Questions

M.1. What standards and practices are used within the pipeline industry to assure quality? Do gas transmission pipeline operators have formal QMS?

M.2. Should PHMSA establish requirements for QMS? If so, why? If so, should these requirements apply to all gas transmission pipelines and to the complete life cycle of a pipeline system?

M.3. Do gas transmission pipeline operators require their construction contractors to maintain and use formal QMS? Are contractor personnel that construct new or replacement pipelines and related facilities already required to read and understand the specifications and to participate in skills training prior to performing the work?

M.4. Are there any standards that exist that PHMSA could adopt or from which PHMSA could adapt concepts for QMS?

M.5. What has been the impact on cost and safety in other industries in which requirements for a QMS have been mandated?

M.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.
- The potential environmental impacts of modifying the existing regulatory requirements.

N. Exemption of facilities installed prior to the regulations

Federal pipeline safety regulations were first established with the initial publication of Part 192 on August 19, 1970. Gas transmission pipelines had existed for many years prior to this, some dating to as early as 1920. Many of these older pipelines had operated safely for years at pressures higher than would have been allowed under the new regulations. To preclude a required reduction in the operating pressure of these pipelines, which the agency believed would not have resulted in a material increase in safety; an exemption was included in the regulations allowing pipelines to operate at the highest actual operating pressure to which they were subjected during the five years prior to July 1, 1970.[7] Safe operation at these pressures was deemed to be evidence that operation could safely continue. This exemption is still in Part 192, at §192.619(a)(3). It has been modified to accommodate later changes that redefined some onshore gathering pipelines as transmission pipelines, allowing the MAOP for those pipelines similarly to be established at the highest actual pressure experienced in the five years before the redefinition.

Many exempt gas transmission pipelines continue to operate in the United States. Some of these pipelines operate at stress levels higher than 72 percent specified minimum yield strength (SMYS), the highest level generally allowed for more modern gas transmission pipelines. Some operate at greater than 80 percent SMYS, the alternate MAOP allowed for some pipelines by regulations adopted October 17, 2008 (72 FR 62148). Under these regulations, operators who seek to operate their pipelines at up to 80 percent SMYS (in Class 1 locations) voluntarily accept significant additional requirements applicable to design, construction, and operation of their pipeline and intended to assure quality and safety at these higher operating stresses. Exempt pipelines are subject to none of these additional requirements.

Exempt pipelines that continue to operate at higher pressures (stress levels) than the regulations would currently allow are now 40 years older than they were when Part 192 was initially promulgated. In many cases, this is more than double the operating lifetime they had accumulated at that time. Time is an important factor in assuring pipeline safety. Pipelines are subject to various time-dependent degradation mechanisms including corrosion, fatigue, and

[7] The pipelines that operate at MAOP determined under this exemption are commonly referred to as "grandfathered" pipelines.

other potential causes of failure. Pipeline operators manage these mechanisms, and many are addressed by regulations in Part 192

Part 192 also includes several provisions other than establishment of MAOP for which an accommodation was made in the initial Part 192. These provisions allowed pipeline operators to use steel pipe that had been manufactured before 1970 and did not meet all requirements applicable to pipe manufactured after Part 192 became effective § 192.55), valves, fittings and components that did not contain all the markings required § 192.63), and pipe which had not been transported under the standard included in the new Part 192 (192.65, subject to additional testing requirements). These provisions allowed pipeline operators to use materials that they had purchased prior to the effective date of the new regulations and which they maintained on hand for repairs, replacements and new installations.

PHMSA is considering changes to its regulations that would eliminate these exemptions. PHMSA expects that materials that had been warehoused prior to 1970 have all been used in the intervening years or, if not, are no longer suitable for use. PHMSA is considering repealing the provisions that allow use of such older materials. PHMSA is considering eliminating the exemption of §192.619(a)(3) for establishing MAOP. This would have the effect of requiring a reduction in the operating pressure for some older gas transmission pipelines to levels applicable to pipelines constructed since 1970.

Questions

N.1. Should PHMSA repeal provisions in Part 192 that allow use of materials manufactured prior to 1970 and that do not otherwise meet all requirements in Part 192?

N.2. Should PHMSA repeal the MAOP exemption for pre-1970 pipelines? Should pre-1970 pipelines that operate above 72% SMYS be allowed to continue to be operated at these levels without increased safety evaluations such as periodic pressure tests, in-line inspections, coating examination, CP surveys, and expanded requirements on interference currents and depth of cover maintenance?

N.3. Should PHMSA take any other actions with respect to exempt pipelines? Should pipelines that have not been pressure tested in accordance with Subpart J be required to be pressure tested in accordance with present regulations?

N.4. If a pipeline has pipe with a vintage history of systemic integrity issues in areas such as longitudinal weld seams or steel quality, and has not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), should this pipeline be required to be pressure tested in accordance with present regulations?

N.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.

- The potential environmental impacts of modifying the existing regulatory requirements.

O. Modifying the Regulation of Gas Gathering Lines

In the Natural Gas Pipeline Safety Act of 1968, Congress gave DOT broad authority to develop, prescribe, and enforce minimum federal safety standards for the transportation of gas by pipeline.[8] That authority did not extend to the gathering of gas in rural areas, which Congress concluded should not be subject to federal regulation.[9]

In 1970, DOT issued its original federal safety standards for the transportation of gas by pipeline.[10] Those standards did not apply to the gathering of gas in rural areas and defined a "gathering line" as "a pipeline that transports gas from a current production facility to a transmission line or main."

In 1974, DOT issued a notice of proposed rulemaking (NPRM) to change its definition of a gas gathering line.[11] The NPRM noted that the original definition had "creat[ed] a vicious circle," both in terms of determining where a gathering line begins and a transmission line ends and where a production facility ends and a gathering line begins. Nonetheless, DOT withdrew the NPRM four years later without taking any final action.[12]

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[8] Pub. L. No. 90-481, 82 Stat. 720 (1968) (currently codified with amendments at 49 U.S.C. §§ 60101 et. seq.).
[9] H.R. REP. NO. 1390 (1968), *reprinted in* 1968 U.S.C.C.A.N. 3223, 3234-35.
[10] 35 Fed. Reg. 317, 318, 320 (Jan. 8, 1970); 35 Fed. Reg. 13248, 13258 (Aug. 19, 1970).
[11] 39 Fed. Reg. 34569 (Sep. 26, 1974).
[12] 43 Fed. Reg. 42773 (Sept. 21, 1978).

In the Pipeline Safety Act (PSA) of 1992,[13] Congress gave DOT the discretion to override the traditional prohibition on the regulation of rural gathering lines. Specifically, the PSA provided DOT with the authority to issue safety standards for "regulated gathering lines," based on the functional and operational characteristics of those lines and subject to certain additional conditions. In the Accountable Pipeline Safety and Partnership Act of 1996, Congress made clear that DOT had the authority to obtain information from the owners and operators of gathering lines to determine whether those lines should be subject to federal safety standards.[14]

In March 2006, PHMSA issued new safety requirements for "regulated onshore gathering lines."[15] Those requirements established a new method for determining if a pipeline is an onshore gathering line, divided regulated onshore gas gathering lines into two risk-based categories (Type A and Type B), and subjected such lines to certain safety standards.

Onshore gas gathering lines are defined based on the provisions in American Petroleum Institute Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," (API RP 80), a consensus industry standard incorporated by reference. Additional regulatory requirements for determining the beginning and endpoints of gathering are also imposed to prevent operator manipulation and abuse.

Type A gathering lines are metallic lines with a MAOP of 20% or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 psig, in a Class 2, 3, or 4 location. These

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[13] Pub. L. No. 102-508, 106 Stat. 3289 (Oct. 24, 1992) (currently codified at 49 U.S.C. § 60101(b)). In 1991, DOT had issued another NPRM to change the definitions for gathering line and production facility and to add a new term, "production field," into the gas pipeline safety regulations. 56 Fed. Reg. 48505 (Sept. 25, 1991).
[14] Pub. L. No. 104-304, § 12, 110 Stat. 3793 (Jan. 3, 1996) (currently codified at 49 U.S.C. 60117(b)).
[15] 71 Fed. Reg. 13289 (Mar. 15, 2006).

lines are subject to all of the requirements in Part 192 that apply to transmission lines, except for § 192.150, the regulation that requires the accommodation of smart pigs in the design and construction of certain new and replaced pipelines, and the Integrity Management requirements of Part 192, Subpart O. Operators of Type A gathering lines are also permitted to use an alternative process for demonstrating compliance with the requirements of Part 192, Subpart N, Qualification of Pipeline Personnel.

Type B gathering lines are metallic lines with an MAOP of less than 20% of SMYS, as well as nonmetallic lines with an MAOP of 125 psig or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location. These lines are subject to less stringent requirements than Type A gathering lines; specifically, any new or substantially changed Type B line must comply with the design, installation, construction, and initial testing and inspection requirements applicable to transmission lines and, if of metallic construction, the corrosion control requirements for transmission lines. Operators must also include Type B gathering lines in their damage prevention and public education programs, establish the MAOP of those lines under § 192.619, and comply with the requirements for maintaining and installing line markers that apply to transmission lines.

Recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may no longer be appropriate. Gathering lines are being constructed to transport "shale" gas that range from 12 to 36inches in diameter with an MAOP of 1480 psig, far exceeding the historical operating parameters of such lines. Current estimates also indicate that there are approximately 230,000 miles of gas gathering lines in the U.S., and that PHMSA only regulates about 20,150 miles of those lines. Moreover, enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. PHMSA has also identified a regulatory gap that permits the potential abuse of the incidental gathering line designation under that standard.

Question

O.1 Should PHMSA amend 49 CFR Part 191 to require the submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines?

O.2 Should PHMSA amend 49 CFR Part 192 to include a new definition for the term "gathering line"?

O.3 Are there any difficulties in applying the definitions contained in RP 80? If so, please explain.

O.4 Should PHMSA consider establishing a new, risk-based regime of safety requirements for large-diameter, high-pressure gas gathering lines in rural locations? If so, what requirements should be imposed?

O.5 Should PHMSA consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering? If so, what are the appropriate risk factors that should be considered in defining the scope of that limitation (e.g. doesn't leave the operator's property, not longer than 1000 feet, crosses no public rights-of-way)?

O.6 Should PHMSA consider adopting specific requirements for pipelines associated with landfill gas systems? If so, what regulations should be adopted and why? Should PHMSA consider adding regulations to address the risks associated with landfill gas that contains higher concentrations of hydrogen sulfide and/or carbon dioxide?

O.7 Internal corrosion is an elevated threat to gathering systems due to the composition of the gas transported. Should PHMSA enhance its requirements for internal corrosion control for gathering pipelines? Should this include required cleaning on a periodic basis?

O.8 Should PHMSA apply its Gas Integrity Management Requirements to onshore gas gathering lines? If so, to what extent should those regulations be applied and why?

O.9. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.

The potential environmental impacts of modifying the existing regulatory requirements.

IV. Regulatory Notices

A. Executive Order 12866, Executive Order 13563, and DOT Regulatory Policies and Procedures

Executive Orders 12866 and 13563 require agencies to regulate in the "most cost-effective manner," to make a "reasoned determination that the benefits of the intended regulation justify its costs," and to develop regulations that "impose the least burden on society." We therefore request comments, including specific data if possible, concerning the costs and benefits of revising the pipeline safety regulations to accommodate any of the changes suggested in this advance notice.

B. Executive Order 13132: Federalism

Executive Order 13132 requires agencies to assure meaningful and timely input by state and local officials in the development of regulatory policies that may have a substantial, direct effect on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. PHMSA is inviting comments on the effect a possible rulemaking adopting any of the amendments discussed in this document may have on the relationship between national government and the states.

C. Regulatory Flexibility Act

Under the Regulatory Flexibility Act of 1980 (5 U.S.C. 601 et seq.), PHMSA must consider whether a proposed rule would have a significant economic impact on a substantial number of small entities. ``Small entities'' include small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations under 50,000. If your business or organization is a small entity and if adoption of any of the amendments discussed in this ANPRM could have a significant economic impact on your operations, please submit a comment to explain how and to what extent your business or organization could be affected and whether there are alternative approaches to this regulations the agency should consider that would minimize any significant impact on small business while still meeting the agency's statutory objectives.

D. National Environmental Policy Act

The National Environmental Policy Act of 1969 requires Federal agencies to consider the consequences of Federal actions and that they prepare a detailed statement analyzing them if the action significantly affects the quality of the human environment. Interested parties are invited to address the potential environmental impacts of this ANPRM. We are particularly interested in comments about compliance measures that would provide greater benefit to the human environment or on alternative actions the agency could take that would provide beneficial impacts.

E. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175 requires agencies to assure meaningful and timely input from Indian Tribal Government representatives in the development of rules that ``significantly or uniquely affect'' Indian communities and that impose ``substantial and direct compliance costs'' on such communities. We invite Indian tribal governments to provide comments on any aspect of this ANPRM that may affect Indian communities.

F. Paperwork Reduction Act

Under 5 CFR Part 1320, PHMSA analyzes any paperwork burdens if any information collection will be required by a rulemaking. We invite comment on the need for any collection of information and paperwork burdens, if any.

G. Privacy Act Statement

Anyone can search the electronic form of comments received in response to any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). DOT's complete Privacy Act Statement was published in the Federal Register on April 11, 2000 (65 FR 19477).

Authority: 49 U.S.C. 60101 et seq.; 49 CFR § 1.53.

Issued in Washington, DC on _August 18, 2011____.

Jeffrey D. Wiese,
Associate Administrator for Pipeline Safety.

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