Subpart C—Technical Standards

Brief Description: Part 101 prescribes the manner in which portions of the radio spectrum may be made available for private operational, common carrier, 24 GHz Service, Local Multipoint Distribution Service, and fixed, microwave operations that require transmitting facilities on land or in specified offshore coastal areas within the continental shelf. Subpart C sets forth technical standards for applications and licenses in the Fixed Microwave Services.

Need: The revised rules provide the interference protection criteria for fixed stations subject to part 101 and requires that transmitters used in the private operational fixed and common carrier fixed point-to-point microwave and point-to-multipoint services under this part must be a type that has been verified for compliance. The need for these rules is ongoing.

Legal Basis: 47 U.S.C. 154, and 303.

Section Number and Titles:

101.105(a)(5) and (6) Interference protection criteria.

101.139(h) and (i) Authorization of transmitters.

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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket ID: PHMSA–2017–0151]

RIN 2137–AF29

Pipeline Safety: Class Location Change Requirements

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

ACTION: Advance notice of proposed rulemaking (ANPRM).

SUMMARY: PHMSA is seeking public comment on its existing class location requirements for natural gas transmission pipelines as they pertain to actions operators are required to take following class location changes due to population growth near the pipeline. Operators have suggested that performing integrity management measures on pipelines where class locations have changed due to population increases would be an equally safe but less costly alternative to the current requirements of either reducing pressure, pressure testing, or replacing pipe. This request for public comment continues a line of discussion from a Notice of Inquiry published in 2013 and a report to Congress in 2016 regarding whether expanding integrity management requirements would mitigate the need for class location requirements.

DATES: Persons interested in submitting written comments on this ANPRM must do so by October 1, 2018.

ADDRESSES: You may submit comments identified by the Docket: PHMSA–2017–0151 by any of the following methods:

E-Gov website: https://www.regulations.gov. This site allows the public to enter comments on any **Federal Register** notice issued by any agency. 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: Identify the Docket ID at the beginning of your comments. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA has received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *https://www.regulations.gov/.*

Note: Comments are posted without changes or edits to *https://www.regulations.gov,* including any personal information provided. There is a privacy statement published on *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Outline of This Document

Background

I. Class Location History and Purpose

The class location concept pre-dates Federal regulation of gas transmission pipelines [1] and was an early method of differentiating areas and risks along natural gas pipelines based on the potential consequences of a hypothetical pipeline failure. Class location designations were previously included in the American Standards Association B31.8–1968 version of the ''Gas Transmission and Distribution Pipeline Systems'' standard, which eventually became the American Society of Mechanical Engineers (ASME) International Standard, ASME B31.8 ''Gas Transmission and Distribution Pipeline Systems.'' The class location definitions incorporated into title 49, Code of Federal Regulations (CFR) § 192.5 were initially derived from the designations in this standard and were first codified on April 19, 1970.[2] These definitions were like the original ASME B31.8 definitions for Class 1 through 3 locations but added an additional Class 4 definition and, with some modifications, still apply today.

Gas transmission pipelines are divided into classes from 1 (rural areas) to 4 (densely populated, high-rise areas) that are based on the number of buildings or dwellings for human occupancy in the area. This concept is to provide safety to people from the effects of a high-pressure natural gas pipeline leak or rupture that could explode or catch on fire. PHMSA uses class locations in 49 CFR part 192 to implement a graded approach in many areas that provides more conservative safety margins and more stringent safety standards commensurate with the potential consequences based on population density near the pipeline. When crafting the natural gas

[1] The Department of Transportation first proposed class location regulations on March 24, 1970 (35 FR 5012). The proposal was part of a series of NPRMs published in response to the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481). The NPRMs were directed at developing a comprehensive system of Federal safety standards for gas pipeline facilities and for the transportation of gas through such pipelines. The class location rulemaking was finalized on August 19, 1970, as part of a consolidated rulemaking establishing the first minimum Federal safety standards for the transportation of natural gas by pipelines (35 FR 13248).

[2] 35 FR 13248.

regulations, DOT's Office of Pipeline Safety (OPS) determined that these more stringent standards were necessary because a greater number of people in proximity to the pipeline substantially increases the probabilities of personal injury and property damage in the event of an accident. At the same time, the external stresses, the potential for damage from third-parties, and other factors that contribute to accidents increase along with the population; consequently, additional protective measures are often needed in areas with greater concentrations of population.

The most basic and earliest use of the class location concept focused on the design (safety) margin for the pipeline. As pipelines are designed based, in part, on the population along their pipeline route and therefore the class location of the area, it is important to decrease pipe stresses in areas where there is the potential for higher consequences or where higher pipe stresses could affect the safe operation of a pipeline in larger-populated areas. Pipeline design factors are derating factors that ensure pipelines are operated below 100 percent of the maximum pipe yield strength. From an engineering standpoint, they were developed based on risk to the public [3] and for piping that may face additional operational stresses.[4] Pipeline design factors vary, ranging from 0.72 in a Class 1 location to 0.40 in a Class 4 location. They are used in the pipeline design formula (§ 192.105) to determine the design pressure for steel pipe, and are generally reflected in the maximum allowable operating pressure (MAOP) based upon a percentage of the specified minimum yield strength (SMYS) at which the pipeline can be operated.[5] [6] Design factors are used along with pipe characteristics in engineering calculations (Barlow's Formula) to calculate the design pressure and MAOP of a steel pipeline. More specifically, the formula at § 192.105 is $P = (2St/D) \times F \times E \times T$, where P is the design pressure, S is the pipe's yield strength, t is the wall thickness of the pipe, D is the diameter of the pipe, F is the design factor per the class location, E is the longitudinal joint factor,[7] and T is the temperature derating factor.[8] The formula in § 192.105 can be used to calculate the MAOP of a 1000 psig pipeline with the same operating parameters (diameter, wall thickness, yield strength, seam type, and temperature) but in different class locations (and therefore different design factors), and the MAOP of that pipeline in the different class locations would be as follows:

- No class location—design factor = 1.0 (none); MAOP = 1000 psig
- Class 1—design factor = 0.72; MAOP = 720 psig
- Class 2—design factor = 0.60; MAOP = 600 psig
- Class 3—design factor = 0.50; MAOP = 500 psig
- Class 4—design factor = 0.40; MAOP = 400 psig

As therefore evidenced, pipelines at higher class locations will have lower operating pressures and maximum allowable operating pressures due to more stringent design factors to protect people near the pipeline.

As natural gas pipeline standards and regulations evolved, the class location concept was incorporated into many other regulatory requirements, including test pressures, mainline block valve spacing, pipeline design and construction, and operations and maintenance (O&M) requirements, to provide additional safety to populated areas. In total, class location concepts affect 12 of 16 subparts of part 192 and a total of 28 individual sections.[9]

A. Class Location Determinations

Pipeline class locations for onshore gas pipelines are determined as specified in § 192.5(a) by using a ''sliding mile.'' The ''sliding mile'' is a unit that is 1 mile in length, extends 220 yards on either side of the centerline of a pipeline, and moves along the pipeline. The number of buildings [10] within this sliding mile at any point during the mile's movement determines the class location for the entire mile of pipeline contained within the sliding mile. Class locations are not determined at any given point of a pipeline by counting the number of dwellings in static mile-long pipeline segments stacked end-to-end.

When higher dwelling concentrations are encountered during the continuous sliding of this mile-long unit, the class location of the pipeline rises commensurately. As it pertains to structure counts, a Class 1 location is a class location unit along a continuous mile containing 10 or fewer buildings intended for human occupancy, a Class 2 location is a class location unit along a continuous mile containing 11 to 45 buildings intended for human occupancy, and a Class 3 location is a class location unit along a continuous mile containing 46 or more buildings intended for human occupancy.[11] Class 4 locations exist where buildings with four or more stories above ground are prevalent. Whenever there is a change in class location that will cause an apparent overlapping of class locations, the higher-numbered class location applies.

B. Class Location—''Cluster Rule'' Adjustments

After proposing the initial natural gas safety regulations in 1970, OPS received several comments stating that the proposed class location definitions could create 2-mile stretches of higher class locations for the sole protection of small clusters of buildings at crossroads or road crossings. Because part 192 regulations become more stringent as class locations increase from Class 1 to 4 locations, pipelines in higher class location areas such as these can result in increased expenditures to the pipeline operator in areas where there is no population. When finalizing the class location definitions as a part of establishing part 192 on August 19, 1970 (35 FR 13248), OPS added a new paragraph to allow operators to adjust the boundaries of Class 2, 3, and 4

[3] For instance, the number of human dwellings near the pipeline or the type of dwelling (hospital, school, playground, nursing care facility, etc.).

[4] This can include piping at compressor stations, metering stations, fabrications, and road or railroad crossings.

[5] Design factors for steel pipe are listed in § 192.111. Class 1 locations have a 0.72 design factor, Class 2 locations have a 0.60 factor, Class 3 locations have a 0.50 factor, and Class 4 locations have a 0.40 design factor.

[6] SMYS is an indication of the minimum stress a pipe may experience that will cause plastic, or permanent, deformation of the steel pipe.

[7] The seam type of a pipeline, per this formula, has a limiting effect on the MAOP of the pipeline. While it is typically ''1.00'' and does not affect the calculation, certain types of furnace butt-welded pipe or pipe not manufactured to certain industry standards will have factors of 0.60 or 0.80, which will necessitate a reduction in design pressure.

[8] The temperature derating factor ranges from 1.000 to 0.867 depending on the operating temperature of the pipeline. Pipelines designed to operate at 250 degrees Fahrenheit and lower have a factor of 1.000, which does not affect the design pressure calculation. Pipelines designed to operate at higher temperatures, including up to 450 degrees Fahrenheit, will have derating factors that will lower the design pressure of the pipeline.

[9] §§ 192.5, 192.8, 192.9, 192.65, 192.105, 192.111, 192.123, 192.150, 192.175, 192.179, 192.243, 192.327, 192.485, 192.503, 192.505, 192.609, 192.611, 192.613, 192.619, 192.620, 192.625, 192.705, 192.706, 192.707, 192.713, 192.903, 192.933, and 192.935.

[10] Per the regulations, a ''building'' is a structure intended for human occupancy, whether it is used as a residence, for business, or for another purpose. For the purposes of this rulemaking, a ''building'' may be interchangeably referred to as a ''home,'' a ''house,'' or a ''dwelling.''

[11] Under § 192.5, Class 1 locations also include offshore areas, and Class 3 locations contain areas where the pipeline lies within 100 yards of a building or a small, well-defined outside area (including playgrounds, recreation areas, and outdoor theaters) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

locations. Under this provision, operators can choose to end Class 4 location boundaries 220 yards from the furthest edges of a group of 4-story buildings, and operators can choose to end Class 2 and 3 boundaries up to 220 yards upstream and downstream from the furthest edges of a group or ''cluster'' of buildings.[12] ''Clustering,'' therefore, is a means of reducing the length of a Class 2, 3, or 4 location in a sliding mile unit that requires a Class 2, 3, or 4 location; in other words, it allows operators to cluster or reduce the amount of pipe that is subject to the requirements of a higher class location.[13]

It is important to note that while clustering allows for the adjustment of the length of class locations in certain areas, it does not change the length of class location units themselves nor the method by which class location units are determined. Further, clustering does not exclude ''buildings for human occupancy'' in a class location unit/sliding mile, so all buildings within a specified class location unit must be protected by the maximum class location level that was determined for the entire class location unit. This concept becomes especially important when other buildings for human occupancy are built within a class location unit/sliding mile where a cluster exists and an operator has adjusted the class location length to exclude certain lengths of pipe outside of the cluster area.

For instance, assume there is a class location unit/sliding mile containing 47 homes close to one another. The class location unit would be a Class 3 location per the definition provided at § 192.5(b). An operator can consider these homes a ''cluster'' and appropriately apply the adjustment at § 192.5(c) so that the boundaries of the Class 3 location are 220 yards upstream and downstream from the furthest edges of the clustered homes (buildings for human occupancy). Therefore, while the entirety of the pipeline is in a Class 3 class location unit, the only pipe subject to Class 3 requirements is the length of the cluster plus 220 yards on both sides of the cluster. The remaining pipe in the class location unit/sliding mile, the pipe that is outside of this clustered area, could therefore be operated at Class 1 requirements rather than at the otherwise-required Class 3 requirements.

However, what would happen if new buildings were built within that sliding mile but away from that single cluster? If, per the example above, there is a cluster of 47 homes at one end of a class location unit/sliding mile, and 3 homes are built at the other end of the class location unit, the operator must count and treat those 3 homes as a second cluster, with the length of the cluster plus 220 yards on both sides of the cluster subject to Class 3 requirements. The pipeline between these two clusters would still be in a Class 3 location per its class location unit, as there would be 50 homes within the sliding mile, but the pipeline between the clusters could be operated under Class 1 location requirements. If the 220-yard extensions of any two or more clusters intercept or overlap, the separate clusters must be considered a single cluster for purposes of applying the adjustment.

An operator must use the clustering method consistently to ensure that all buildings for human occupancy within a class location unit are covered by the appropriately determined class location requirements. Any new buildings for human occupancy built in a class location unit where clustering has been used must also be clustered, whether they form a new, independent cluster or are added to the existing cluster. Note that even a single house could form the basis of a second cluster under this requirement, as all buildings within a specified class location unit must be protected by the maximum class location level that was determined for the entire class location unit.

PHMSA's interpretation to Air Products and Chemicals, Inc., issued on March 11, 2015,[14] explains and diagrams this concept further.

II. Changes in Class Location Due to Population Growth

Class locations can change as the population living or working near a pipeline grows and, as outlined earlier, are specifically determined based on the density of dwellings within the 440-yard-wide (quarter-mile-wide) sliding mile down the pipeline centerline. Class locations are used to determine a pipeline's design factor, which is a component of the design formula equation at § 192.105 and ultimately factors into the pressure at which the pipeline is operated. As population around a pipeline increases and the pipeline's class location increases, the numeric value of the design factor decreases, which translates, via the formula at § 192.105, into a lower MAOP for the pipeline. To illustrate this, a Class 4 location containing a prevalence of 4-or-more-story buildings has a safety factor of 0.4, whereas a Class 2 location containing 11 to 45 dwellings has a safety factor of 0.6. If a Class 2 location is very quickly developed to a point where there is a prevalence of 4-or-more story buildings, the corresponding difference in safety factor when the class location changes, from a 0.6 to a 0.4, equates to a 33% reduction in MAOP per the design formula equation.

A change in class location requires operators to confirm safety factors and to recalculate the MAOP of a pipeline. If the MAOP per the newly determined class location is not commensurate with the present class location, current regulations require that pipeline operators (1) reduce the pipe's MAOP to reduce stress levels in the pipe; (2) replace the existing pipe with pipe that has thicker walls or higher yield strength to yield a lower operating stress at the same MAOP; or (3) pressure test at a higher test pressure if the pipeline segment has not previously been tested at the higher pressure and for a minimum of 8 hours.[15] Depending on the pipeline's test pressure and whether it meets the requirements in §§ 192.609 and 192.611 (''Change in class location: Required study,'' and ''Change in class location: Confirmation or revision of maximum allowable operating pressure,'' respectively), an operator can base the pipeline's MAOP on a certain safety factor times the test pressure for the new class location as long as the corresponding hoop stress of the pipeline does not exceed certain percentages of the specified minimum yield strength (SMYS) of the pipe.[16]

[12] See § 192.5(c)(1) & (2).

[13] For example, if all buildings for human occupancy in a sliding mile containing enough buildings to require a Class 3 location were clustered in the middle of that sliding mile, the Class 3 area would end 220 yards from the nearest building (on either side of the cluster through which the pipeline passes) rather than at the end of the 1-mile class location unit that would otherwise be the basis for classification. Thus, if the cluster were 200 yards in length, the total length of the Class 3 area would be 640 yards (220 + 200 + 220).

[14] PHMSA Interpretation #PI–14–0017, available at *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/legacy/interpretations/Interpretation%20Files/Pipeline/2015/Air_Products_PI_14_0017_10_01_2014_Part_192.5.pdf.*

[15] See § 192.611 as appropriate to one-class changes (*e.g.,* Class 1 to 2 or Class 2 to 3 or Class 3 to 4). As an example, for a Class 1 to Class 2 location change, the pipeline segment would require a pressure test to 1.25 times the MAOP for 8 hours. Following a successful pressure test, the pipeline segment would not need to be replaced with new pipe, but the existing design factor of 0.72 for a Class 1 location would be acceptable for a Class 2 location.

[16] See § 192.611. Specifically, if the applicable segment has been hydrostatically tested for a period of longer than 8 hours, the MAOP is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72% of

Continued

This is often referred to as a ''one-class bump,'' as an operator can use this method when class locations change from a Class 1 to 2, a Class 2 to a 3, or a Class 3 to a 4.

The §§ 192.5 and 192.611 requirements to change-out pipe, re-pressure test, or de-rate pipe to a lower MAOP when population growth occurs and requires a class location change are the most significant reasons that operators request that class locations be revised or eliminated. Throughout the process of considering class location changes,[17] comments PHMSA received from the trade associations state that reducing a pipeline's operating pressure below that at which the pipeline historically operated may unacceptably restrict deliveries to natural gas customers. These same commenters suggest that pressure testing pipelines may be practicable in select cases, but the test pressure required for higher class locations may exceed what a pipeline is designed to accommodate. Operators also contend that they should not have to change out pipe when a class location change occurs if the operator can prove that the pipe segment is fit for service through integrity assessments.[18]

III. Class Location Change Special Permits

As population growth occurs around pipelines that were formerly in rural areas, some operators have applied for special permits to prevent the need for pipe replacement or pressure reduction when the class location changes. A special permit is an order issued under § 190.341 that waives or modifies compliance with regulatory requirements if the pipeline operator requesting it demonstrates a need and PHMSA determines that granting the special permit would be consistent with pipeline safety. PHMSA performs extensive technical analysis on special permit applications and typically grants special permits on the condition that operators will perform alternative measures to provide an equal or greater level of public safety. PHMSA publishes a notice and request for comment in the **Federal Register** for each special permit application received and tracks issued, denied, and expired special permits on its website.

Since 2004, PHMSA has approved over 15 class location special permits based on operators adopting additional conditions, including certain operating safety criteria and periodic integrity evaluations.[19] [20] Generally, the additional conditions PHMSA requires are designed to identify and mitigate integrity issues that could threaten the pipeline segment and cause failure, especially given the fact that the majority of class location special permits it receives and reviews are for older pipelines that may have manufacturing, construction, or ongoing maintenance issues, such as seam or pipe body cracking, poor external coating, insufficient soil cover, lack of material records, dents, or repairs not made to class location design safety factors.

Typically, PHMSA requires operators to incorporate the affected segments into the company's O&M procedures and integrity management plan, perform additional assessments for threats to the pipeline segments identified during an operator's risk assessment, perform additional cathodic protection[21] and corrosion control measures, and repair any discovered anomalies to a specified schedule. Therefore, the additional monitoring and maintenance requirements PHMSA prescribes through this process help to ensure the integrity of the pipe and protection of the population living near the pipeline segment at a comparable margin of safety and environmental protection throughout the life of the pipe compared to the regulations as written. The class location change special permits that PHMSA has granted have allowed operators to continue operating the pipeline segments identified under the special permits at the current MAOP based on the previous class locations. PHMSA notes that it developed its class location special permit process by adapting Integrity Management (IM) concepts and published the typical considerations for class location change special permit requests in the **Federal Register** in 2004.[22] Based on its experiences when renewing some of the earliest class location change special permits, PHMSA has extended the expiration date of its class location change special permits from 5 years to 10 years. This extension should provide additional regulatory certainty to operators that apply for these permits. Further, throughout the renewal process of existing special permits, PHMSA has not significantly changed the original conditions imposed on individual operators. While PHMSA can make modifications to its special permit conditions when it is in the interest of safety and the public to do so, PHMSA has determined that the present special permit conditions and process are consistent with public safety.

A. Special Permit Conditions

In the special permit conditions and criteria PHMSA published in the **Federal Register** on June 29, 2004, PHMSA outlines several ''threshold conditions'' pipelines must meet to be considered for a special permit when class locations change. For instance, PHMSA does not consider any pipeline segments for a special permit where the class location those segments are in changes to a Class 4 location. Typically, PHMSA receives special permit requests

SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.

[17] See Section IV of this document. In the context of this rulemaking, PHMSA has been considering issues related to class location requirements since publishing an ANPRM on the gas transmission regulations in 2011. Following that, PHMSA published a notice of inquiry soliciting comments on expanding gas IM program requirements and mitigating class location requirements (78 FR 46560; August 1, 2013) and held a public meeting on the notice of inquiry topics on April 16, 2014 (both actions under Docket Number PHMSA–2013–0161). PHMSA also received comments on the issues discussed in this rulemaking in the docket titled ''Transportation Infrastructure: Notice of Review of Policy, Guidance, and Regulations Affecting Transportation Infrastructure Projects'' which was noticed in the **Federal Register** on June 8, 2017 (82 FR 26734; Docket Number OST–2017–0057).

[18] Operators did not outline the type of integrity assessments that would be appropriate from their perspective nor the factors that should be considered to determine whether a pipeline segment is fit for service (such as pipe, pipe seam, or coating conditions; O&M history; material properties; pipe depth of cover; non-destructive testing of girth welds; type pipe coatings used and if they shield cathodic protection; seam type; failure or leak history; and pressure testing or acceptance criteria and any re-evaluation intervals).

[19] Special permit conditions are implemented to mitigate the causes of gas transmission incidents and are based on the type of threats pertinent to the pipeline. The conditions are generally more heavily weighted on identifying: Material, coating and cathodic protection issues, pipe wall loss, pipe and weld cracking, depth of pipe cover, third party damage prevention, marking of the pipeline and pipeline right-of-way patrols, pressure tests and documentation, data integration of integrity issues, and reassessment intervals.

[20] Examples of PHMSA's class location special permit conditions can be found at: *https://primis.phmsa.dot.gov/classloc/docs/SpecialPermit_ExampleClassLocSP_Conditions_090112_draft1.pdf,* and more information about PHMSA's special permit process for class location changes can be found at: *https://primis.phmsa.dot.gov/classloc/documents.htm*

[21] Cathodic protection is a technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell. This can be achieved with a special coating on the external surface of the pipeline along with an electrical system and anodes buried in the ground or with a ''sacrificial'' or galvanic metal acting as an anode. In these systems, the anode will corrode before the protected metal will.

[22] **Federal Register** (69 FR 38948, June 29, 2004). Additional guidance is provided online at: *http://primis.phmsa.dot.gov/classloc/index.htm.* Public notices were published in **Federal Register**: 69 FR 22115 and 69 FR 38948, dated April 23, 2004 and June 29, 2004: Docket No. RSPA–2004–17401—Pipeline Safety: Development of Class Location Change Waiver (Special Permit).

for pipeline segments where the class location is changing from Class 1 to Class 3. PHMSA also does not consider for class location change special permits any segments that have bare pipe or wrinkle bends. Other manufacturing- and construction-related items PHMSA considers include whether the applicable segments have certain seam types that may be more prone to defects and failures, whether the pipe has certain coating types that provide an adequate level of cathodic protection, and the design strength of the pipe.

There are also operation and maintenance factors that PHMSA considers when evaluating pipeline segments for class location change special permit feasibility. For example, PHMSA doesn't consider for a Class 1 to Class 3 location change special permit any pipe segments that operate above 72 percent SMYS. Operators also need to produce a hydrostatic test record showing the segment was tested to 1.25 times the MAOP. Also, operators are required to have pipe material records to document the pipelines diameter, wall thickness, strength, seam type and coating type. For operators who do not have these records, PHMSA requires they make these records per the special permit conditions. PHMSA often requires operators to operate each applicable segment at or below its existing MAOP as well.

As part of the special permit conditions, operators are required by PHMSA to incorporate the applicable pipeline segments into their IM program and inspect them on a regular basis according to the operator's procedures. As an extension of this requirement, operators must perform in-line inspections on the applicable segments, and the segments must not have any significant anomalies that would indicate any systemic problems. Additionally, PHMSA's published special permit criteria defines a ''waiver inspection area,'' also known as a ''special permit inspection area,'' as up to 25 miles of pipe on either side of the applicable segment. Operators must incorporate these areas into their IM programs as well and inspect and repair them per the operator's IM program procedures. Some of the factors PHMSA uses when deciding the length of special permit inspection areas are based on factors including what class location the surrounding pipe is in and whether class location ''clustering'' has been used. For both the special permit segments and the special permit inspection areas, PHMSA also typically requires operators to perform assessments and surveys to identify pipe that may be susceptible to certain issues, especially seam or cracking issues in the pipe seam or pipe body, based on the coating type, vintage, or manufacturing of the pipe. Pipelines in the special permit segments or in the special permit inspection areas that have had a leak or failure history are also taken into consideration when PHMSA develops an individual special permit's conditions so as to prevent similar issues in the future. Further, PHMSA looks at the enforcement history of an operator applying for a special permit as a benchmark for how the operator has followed the Federal Pipeline Safety Regulations when developing the conditions following a special permit request.

In class location change special permit requests, PHMSA also ensures that integrity threats to pipelines in special permit segments and special permit inspection areas are addressed in operator operations and management plans, including a systematic, ongoing program to review and remediate pipeline safety concerns. Some of the typical integrity and safety threats PHMSA would expect operators to address include pipe coating quality, cathodic protection effectiveness, stress corrosion and seam cracking, and any long-term pipeline system flow reversals. To this end, PHMSA often requires coating condition surveys, the remediation of coating, and cathodic protection systems for pipelines where the operator has requested a class location change special permit. Any data gathered on the special permit area and special permit inspection area would have to be incorporated into the operator's greater IM program.

PHMSA incorporates these conditions into class location change special permit requests to ensure that operators meet or exceed the threshold requirements with equivalent safety to the provisions in the Federal Pipeline Safety Regulations that are being waived and ensure that granting the special permit will not be inconsistent with safety.

IV. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011—Section 5

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112–90) was enacted. Among the many provisions of the Act, Section 5 required PHMSA to evaluate whether IM system requirements, or elements thereof, should be expanded beyond high-consequence areas (HCA) and, with respect to gas transmission pipeline facilities, whether applying IM program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements. PHMSA was required to report the findings of this evaluation to Congress and was authorized to issue regulations pursuant to the findings of the report following a prescribed review period.

A. 2013 Notice of Inquiry: Class Location Requirements

In August 2013, through a Notice of Inquiry, PHMSA solicited comments on whether expanding IM requirements would mitigate the need for class locations in line with the Section 5 mandate of the 2011 Pipeline Safety Act.[23] Several topics were discussed, including whether class locations should be eliminated and a single design factor used, whether design factors should be increased for higher class locations, and whether pipelines without complete material records should be allowed to use a single design factor if class locations were to be eliminated.[24]

There was broad consensus among PHMSA's stakeholders that eliminating class locations entirely would not lead to improvement to pipeline safety. Further, commenters noted that establishing a single design factor in lieu of class location designations might be too complicated to implement. Many commenters noted that any changes in class location requirements would impact not only the classifications of many pipelines but would also possibly create several unintended consequences within part 192, as the class location requirements are referenced or built upon throughout the natural gas regulations.

Several industry trade groups had suggestions for changing the class location regulations, and these suggestions were developed further through subsequent discussions at advisory committee meetings and at public workshops. The Interstate Natural Gas Association of America (INGAA) noted that IM should be extended beyond HCAs with the caveat that PHMSA should examine the effects of such a change on other areas of the pipeline safety regulations. Along with this, it suggested that PHMSA revise certain operations and maintenance requirements that may no longer be necessary given technological advances and IM activities.

[23] **Federal Register** (78 FR 46560, August 1, 2013).

[24] Regarding these questions, PHMSA received 30 comment letters, available at *www.regulations.gov* at docket PHMSA–2013–0161.

B. 2014 Pipeline Advisory Committee Meeting, Class Location Workshop, and Subsequent Comments

On February 25, 2014, PHMSA hosted a joint meeting of the Gas and Liquid Pipeline Advisory Committees.[25] At that meeting, PHMSA updated the committees on its activities regarding the Section 5 mandate of the 2011 Pipeline Safety Act, and committee members and members of the public provided their comments.

INGAA, reinforcing its comments on the 2013 Notice of Inquiry, noted that the original class location definitions in ASME B31.8 were intended to provide an increased margin of safety for locations of higher population density and stated that IM is a much better risk management tool than class locations. INGAA reiterated that it intends for its members to perform elements of IM on pipelines outside of HCAs.

On April 16, 2014, PHMSA sponsored a Class Location Workshop to solicit comments on whether applying the gas pipeline IM program requirements beyond HCAs would mitigate the need for gas pipeline class location requirements. Presentations were made by representatives from PHMSA, the National Energy Board of Canada (NEB), National Association of Pipeline Safety Representatives (NAPSR), pipeline operators, industry groups, and public interest groups.[26]

During the workshop, INGAA representatives noted that the current class location regulations require changes that result in the replacement of ''good pipe,'' and the special permit process for class location changes should be embedded in part 192. Representatives from the American Gas Association (AGA) noted that applying the current class location change requirements can cost more than $1 million per change. AGA claimed the special permit process for class location changes is burdensome, the renewal process is increasingly complex, and the outcome is uncertain.[27] Therefore, AGA suggested eliminating the special permit process for class location changes and incorporating specific requirements for special permits into part 192 as part of the base regulations. AGA recommended two approach methods, one based on IM and the other using the current class location approach.

Public interest groups including Accufacts and the Pipeline Safety Trust (PST) pointed out how deeply the concept of class locations is embedded in part 192, while also noting that IM requirements and class locations overlap in densely populated areas to provide a redundant, but necessary, safety regime. The PST also suggested that, in time, the older class location method potentially could be replaced with an IM method for regulation. However, the PST noted that incidents and data suggest there is room for improvement in the IM regulations, as data shows higher incident rates in HCAs than in non-HCAs, and noted that pipe installed after 2010 has a higher incident rate than pipe installed a decade earlier. Similarly, Accufacts noted that the incident at San Bruno, CA, exposed weaknesses in the operator's IM program and demonstrated that the consequences resulting from the incident spread far beyond the potential radius in which they were expected to occur.[28] Therefore, Accufacts suggested that shifting the class location approach to solely an IM approach might decrease the protection of public safety.

Following the Class Location Workshop, INGAA submitted additional comments to the docket stating that advancements in IM technology and processes have superseded the need for mandatory pipe replacement following a class location change. It noted that, in the past, it was logical to replace a pipeline when class locations changed because of the widespread belief that thicker pipe would take longer to corrode and would withstand greater external forces, such as damage from excavators, before failure. However, given current technology, improvements in pipe quality, and ongoing regulatory processes such as IM, operators can mitigate most threats without the need for pipe replacement. Therefore, INGAA offered an approach to class locations changes to not require pipe replacement for existing pipelines if pipe segments meet certain requirements that are in line with current IM requirements. Specifically, INGAA suggested that pipelines meeting a ''fitness for service'' standard in 18 categories of requirements could address potential safety concerns and preclude the need for pipe replacement.[29] The 18 categories are very similar to the special permit conditions that PHMSA uses for a Class 1 to 3 location special permit as noted in the 2004 **Federal Register** notice.[30]

C. 2016 Class Location Report

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 required that PHMSA evaluate whether IM should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. In its report titled ''Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements,'' [31] which was submitted to Congress in April 2016 concurrently with the publication of the NPRM titled ''Safety of Gas Transmission and Gathering Pipelines'' (81 FR 20722), PHMSA noted that the application of IM program elements, such as assessment and remediation timeframes, beyond HCAs would not warrant the elimination of class locations.

PHMSA notes that class locations affect all gas pipelines and are integral to determining MAOPs; design pressures; pipe wall thickness; valve spacing; HCAs, in certain cases; and O&M inspection, surveillance, and repair intervals. While IM measures are a critical step towards pipeline safety and are important to mitigate risk, the assessment and remediation of defects do not adequately compensate for these other aspects of class locations. Thus, as outlined in the report, PHMSA determined the existing class location

[25] The Pipeline Advisory Committees are statutorily mandated advisory committees that advise PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas and hazardous liquid pipelines (49 U.S.C. 60115). These Committees were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. app. 1–16) and the Federal Pipeline Safety Statutes (49 U.S.C. chap. 601–603). Each committee consists of 15 members, with membership divided among Federal and State agency representatives, the regulated industry, and the public.

[26] Meeting presentations are available online at: *http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95.*

[27] PHMSA notes that the special permit process is outlined in § 190.341 and is no different for the class location regulations than for any other pipeline safety regulation. Of the 18 special permits up for renewal from 2010–2017, 9 of them were for class location changes. When reviewing the class location change permits up for renewal, PHMSA found no safety reason to extensively modify any of the prior permits and made no major revisions to any of the previously imposed safety conditions.

[28] The potential impact radius for the ruptured pipe segment involved in the San Bruno incident was calculated at 414 feet. However, the NTSB, in its accident report (NTSB/PAR–11/01), noted that the subsequent fire damage extended to a radius of about 600 feet from the blast center.

[29] Those 18 categories were as follows: Baseline Engineering and Record Assessments—Girth Weld Assessment, Casing Assessment, Pipe Seam Assessment, Field Coating Assessment, Cathodic Protection, Interference Currents Control, Close Interval Survey, Stress Corrosion Cracking Assessments, In-line Inspection Assessments, Metal Loss Anomaly Management, Dent Anomaly Management, Hard Spots Anomaly Management. Ongoing Requirements—Integrity Management Program, Root Cause Analysis for Failure or Leak, Line Markers, Patrols, Damage Prevention Best Practices, Recordkeeping & Documentation.

[30] See also: *http://primis.phmsa.dot.gov/classloc/index.htm.*

[31] *https://www.regulations.gov/document?D=PHMSA-2011-0023-0153.*

requirements were appropriate for maintaining pipeline safety and should be retained. Therefore, any revisions to the class location requirements would have to be forward-looking (*i.e.,* applying to pipelines constructed after a certain effective date) and would have to comport with the existing regulatory regime to provide commensurate safety if any changes are made to aspects of pipeline safety related to design and construction, which is where key safety benefits of class locations are realized.[32]

As a part of the continuing discussion on class location changes and subsequent pipe replacement, PHMSA summarized at the end of the Class Location Report the concerns operators expressed regarding the cost of replacing pipe in locations that change from a Class 1 to a Class 3 location or a Class 2 to a Class 4 location. As discussed throughout the document, operators submitted that the safe operation of pipelines constructed in Class 1 locations that later change to Class 3 locations can be achieved using current IM practices.

However, over the past decade, PHMSA observed problems with pipe and fitting manufacturing quality, including low-strength material;[33] construction practices; welding; field coating practices; IM assessments and reassessment practices;[34] [35] and record documentation practices.[36] [37] These issues give PHMSA pause in considering approaches allowing a two-class bump (Class 1 to 3 or Class 2 to 4) without requiring pipe replacement, especially for higher-pressure transmission pipelines.

PHMSA stated in the conclusion of its Class Location Report that it would further evaluate the feasibility and the appropriateness of alternatives to address issues pertaining to pipe replacement requirements, continue to reach out to and consider input from all stakeholders, and consider future rulemaking if a cost-effective and safety-focused approach to adjusting specific aspects of class location requirements could be developed to address the issues identified by industry. In doing so, PHMSA would evaluate alternatives in the context of other issues it is addressing related to new construction quality- and safety-management systems and will also consider inspection findings, IM assessment results, and lessons learned from past incidents. Therefore, PHMSA has initiated this rulemaking to gain further information on analyzing the current requirements resulting in pipe replacement and alternatives to that practice.

V. INGAA Submission on Regulatory Reform—Proposal To Perform IM Measures in Lieu of Pipe Replacement When Class Locations Change

On July 24, 2017, INGAA submitted comments to a DOT docket regarding regulatory review actions (Docket No. OST–2017–0057). In its submission, INGAA estimated that gas transmission pipeline operators incur annual costs of $200–$300 million[38] nationwide replacing pipe solely to satisfy the class location change regulations and requested PHMSA consider revising the current class location change regulations to include an alternative beyond pressure reduction, pressure testing, or pipe replacement.

INGAA's proposed alternate approach focuses on recurring IM assessments that would leverage advanced assessment technologies to determine whether the pipe condition warrants pipe replacement in areas where the class location has changed. INGAA states that such an approach would further promote IM processes and principles throughout the nation's gas transmission pipeline network, improve economic efficiency by reducing regulatory burden, and help fulfill the purposes of Section 5 of the 2011 Pipeline Safety Act.

INGAA claims that the current alternatives to pipe replacement following a class location change do not reflect the substantial developments in IM processes, technologies, and regulations over the past 15-plus years. More specifically, in-line inspection (ILI) technologies, such as high-resolution magnetic flux leakage tools, can precisely assess the presence of corrosion and other potential defects, allowing an operator to establish whether a pipeline segment requires remediation or replacement.[39]

INGAA further notes that PHMSA's proposed rulemaking titled ''Safety of Gas Transmission and Gathering Pipelines'' aims to expand IM assessments to newly defined ''Moderate Consequence Areas'' (proposed § 192.710), and such an expansion provides a framework for developing an alternative for managing class location changes. INGAA suggests that the costs saved from avoiding pipe replacement using such an alternative could mitigate, to some degree, part of the costs of the proposed rulemaking. Additionally, INGAA notes that the proposed rulemaking contains several new provisions that will require operators to better manage the integrity of their pipelines by implementing more preventative and mitigative measures to manage the threat of corrosion. INGAA states that the inclusion of such corrosion control measures as a part of a program for managing the integrity of pipeline segments, including ones that have experienced class location changes, would further justify the development of an IM-focused alternative to class location changes.

Based on those statements, INGAA recommends PHMSA develop an alternative approach to § 192.611 that leverages the proposed § 192.710 for areas outside of HCAs and the IM requirements at § 192.921 to require recurring IM assessments and incorporation of those affected pipeline segments into IM programs. Further, INGAA suggests this approach require operators to reconfirm pipeline MAOP in a changed class location for any pipeline segment without traceable, verifiable, and complete records of a hydrostatic pressure test supporting the segment's previous MAOP.

PHMSA acknowledges that the class location change regulations predate the development of modern pipeline inspection technology such as ILI, above-ground surveys, and modern integrity management processes. In fact, it wasn't until the mid-1990s that PHMSA, following models from other industries such as nuclear power, started to explore whether a risk-based approach to regulation could improve public and environmental safety. PHMSA finalized the IM regulations for gas transmission pipelines on December

[32] In its comments following the public workshop on Class Locations in 2014, INGAA noted that, after further analysis, it appears that applying the Potential Impact Radius (PIR) method to existing pipelines may be unworkable.

[33] PHMSA has documented pipe material low-strength issues through an advisory bulletin and the following website link: *http://primis.phmsa.dot.gov/lowstrength/index.htm.*

[34] IM and operational procedures and practices were issues in the Pacific Gas & Electric (PG&E) San Bruno, CA, rupture in September 2010 and the Enbridge Marshall, MI, rupture in July 2010.

[35] PHMSA issued Advisory Bulletins ADB–11–01 and ADB–2012–10 to operators regarding IM meaningful metrics and assessments on January 10, 2011, and December 5, 2012, respectively, which can be reviewed at: *http://phmsa.dot.gov/pipeline/regs/advisory-bulletin.*

[36] PHMSA issued Advisory Bulletin, ADB–12–06, concerning documentation of MAOP on May 7, 2012, which can be reviewed at: *http://phmsa.dot.gov/pipeline/regs/advisory-bulletin.*

[37] Also note PHMSA's Advisory Bulletin titled ''Deactivation of Threats,'' issued March 16, 2017 (82 FR 14106).

[38] PHMSA requests further substantiation of this estimate. In extrapolating the national data, PHMSA estimates this number is the cost incurred for *all* pipe replacement projects on transmission lines, not just those projects triggered in response to class location changes.

[39] PHMSA notes that ILI and in-the-ditch evaluation technologies for crack identification are under development and could further be improved.

15, 2003,[40] in response to tragic incidents on pipelines in Bellingham, WA, in 1999 and near Carlsbad, NM, in 2000, which killed 3 people and 12 people, respectively. The IM regulations designated HCAs where operators would perform periodic assessments of the condition of their pipelines and make necessary repairs within specific timeframes if discovered anomalies met certain criteria. More specifically, the IM regulations outline the risk-based processes that pipeline operators must use to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines.

For many years, the pipeline industry used internal steel brush devices (''cleaning pigs'') moved by product flow to clean the inside of their pipelines. This pigging concept was later adapted through the application of technology to measure and record irregularities in the pipe and welds that may represent corrosion, cracks, deformations, and other defects. Now operators use ILI technology (''smart pigging or ILI'') as a backbone of the modern IM program. ILI tools are inserted into pipelines at locations, such as near valves or compressor stations, that have special configurations of pipes and valves where the ILI tools can be loaded into launchers, the launchers can be closed and sealed, and the flow of the product the pipeline is carrying can be directed to launch the tool down the pipeline. A similar setup is located downstream where the tool is directed out of the main line into a receiver so that an operator can remove the tool and retrieve the recorded data for analysis and reporting. ILI tools come in several different varieties that have distinct advantages and disadvantages over other methods of pipeline assessment. For instance, while some ILI tools might be able to reliably determine whether a pipeline has internal corrosion, the same tool might not be able to determine whether the pipeline has any crack indications. In selecting the tools most suitable for inline inspections, pipeline operators must know the type of threats that are applicable to the pipeline segment. Threats that ILI tools can identify typically include existing pipe wall thickness, pipe wall changes, pipe wall loss, cracking, and dents.

At the time the class location regulations were promulgated, it was logical to replace a pipeline when population growth resulted in a class location change in order to restore the safety margin appropriate for that location because the industry did not have the technology that is available today to learn the *in situ* material condition of the pipe. Further, since the existing pipe would not achieve a similar safety margin as replaced pipe, operators would need to use applicable inspection technology and pressure testing to ensure pipe has the correct wall thickness; strength; seam condition; toughness; no detrimental cracking or corrosion in the pipe body or seam; and a pipe coating that has not deteriorated or shields cathodic protection currents to allow corrosion or cracking issues such as girth weld cracking, stress corrosion cracking, or selective seam weld corrosion.

Currently, operators are not required to inspect pipelines or otherwise perform IM on those portions of pipelines unless they are within high consequence areas (HCAs) or the operator otherwise voluntarily assesses them and performs remediation measures for threats to the pipeline. As such, while prudent operators may know the characteristics and conditions of their pipelines outside of HCAs and can be confident that they can manage class location change expectations through the performance of IM measures, some operators may not.

PHMSA notes that while class locations and HCAs both provide additional protection to areas with high population concentrations, they were designed for different purposes. Unlike class locations, which provide blanket levels of safety throughout the nation's pipeline network at all locations by driving MAOP and design, construction, testing, and O&M requirements, the purpose of the IM regulations is to provide a structure for operators to focus their resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. Whereas over time the safety margins that class locations provide can be reduced due to corrosion or other types of pipe degradation, IM requirements provide a continuing minimum safety margin for more densely populated areas because operators are required to inspect and repair those applicable pipelines at a minimum of every 7 years and more frequently based upon risk assessments of threats to the segment in the HCA.

PHMSA acknowledges that applying modern IM assessments and processes could potentially be a comparable alternative to pipe change-outs. PHMSA notes that if operators perform integrity assessments on significant portions of non-HCA pipe mileage, PHMSA could further consider operators using such assessments to determine whether pipe in a changed class location is fit for service rather than having to replace it.

PHMSA is concerned, however, that some issues that result in pipeline failures, including poor construction practices[41] and operational maintenance threats, are not always being properly assessed and mitigated by operators, whether due to lack of technology or other causes. Further, as the incident at San Bruno in 2010 showed, operators may not have traceable, verifiable, and complete records of pipe properties, such as pipe material yield strength, pipe wall thickness, pipe seam type, pipe and seam toughness, and coating quality, that are critical and necessary for IM processes and pipeline safety in Class 3 and 4 locations and HCAs where there are higher population densities. PHMSA also points out that there might be instances where a pipeline may be in ''good condition'' from a visual standpoint, but it may not have the initial pipe manufacturing, pipe strength, construction quality, and O&M history requirements that add the extra level of safety required by the regulations for the higher population density area and the MAOP.[42] Section 192.611 already allows a ''one-class location'' bump for pipeline class locations that are in satisfactory physical condition and have the required pressure test.

Because of these factors, PHMSA seeks comment on the potential safety consequences of altering the current class location methodology and moving to an IM-only method in certain areas.

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[40] 68 FR 69778; Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines).

[41] PHMSA has met with operators constructing new pipelines on several occasions to discuss issues found during inspection. To reach out to all members of the pipeline industry, PHMSA hosted a public workshop in collaboration with our State partners, the Federal Energy Regulatory Commission (FERC) and Canada's National Energy Board (NEB) in April 2009. The objective of the workshop was to inform the public, alert the industry, review lessons learned from inspections, and to improve new pipeline construction practices prior to the 2009 construction season. This website makes available information discussed at the workshop and provides a forum in which to share additional information about pipeline construction concerns. This workshop focused on transmission pipeline construction. *http://primis.phmsa.dot.gov/construction/index.htm.*

[42] Note that the potential impact radius (PIR) in Integrity Management (IM) does not give any criteria to establish the pipelines operating pressure, anomaly repair criteria, safety surveys for leaks, 3rd party encroachments, etc. When Class locations change (from additional dwellings for human occupancy) from one-level to a higher level there are cut-off levels that may require a different design factor, pressure test, or maintenance criteria. For pipe to be replaced the class location change would have to be from a Class 1 to 3 or Class 2 to 4, which is a large increase in dwellings along the pipeline.

VI. Questions for Consideration

PHMSA is requesting comments and information that will be used to determine if revisions should be made to the Federal Pipeline Safety Regulations regarding the current requirements operators must meet when class locations change. The list of questions below is not exhaustive and represents an effort to help in the formulation of comments. Any additional information that commenters determine would be beneficial to this discussion is also welcomed.

Q1—When the population increases along a pipeline route that requires a class location change as defined at § 192.5, should PHMSA allow pipe integrity upgrades from Class 1 to Class 3 locations by methods other than pipe replacement or special permits?[43] Why or why not?

1a.—Should part 192 continue to require pipe integrity upgrades when class locations change from Class 1 to Class 3 locations or Class 2 to 4 locations? Why or why not?

1b.—Should part 192 continue to require pipe integrity upgrades from Class 1 to Class 3 locations for the ''cluster rule'' (see § 192.5(c)) when 10 or fewer buildings intended for human occupancy have been constructed along the pipeline segment? Why or why not?

1c.—Should part 192 continue to require pipe integrity upgrades for grandfathered pipe (*e.g.,* pipe segments without a pressure test or with an inadequate pressure test, operating pressures above 72% SMYS, or inadequate or missing material records; see § 192.619(c))? Why or why not?

Q2—Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement, lower the operating pressure, or pressure test at a higher pressure; see § 192.611) when class locations change from Class 1 to Class 3 due to population growth within the sliding mile? Why or why not?

2a.—If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?

Q3—Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement with a more conservative design safety factor or a combination of pressure test and lower MAOP) when class locations change due to additional structures being built outside of clustered areas within the sliding mile, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)? Why or why not?

3a.—If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?

3b.—At what intervals and in what timeframes should operators be required to assess these pipelines and perform remediation measures?

Q4—If PHMSA allows operators to perform certain IM measures in lieu of pipe replacement when class locations change from Class 1 to Class 3, should some sort of ''fitness for service'' standard determine which pipelines are eligible? Why or why not?

4a.—If so, what factors should make a pipeline eligible or ineligible?

(i) Should grandfathered pipe (lacking records, including pressure test or material records) or pipe operating above 72% SMYS be eligible? Why or why not?

(ii) Should pipe that has experienced an in-service failure, was manufactured with a material or seam welding process during a time or by a manufacturer where there are now known integrity issues or has lower toughness in the pipe and weld seam (Charpy impact value) be eligible? Should pipe with a failure or leak history be eligible? Why or why not?

(iii) Should pipe that contains or is susceptible to cracking, including in the body, seam, or girth weld, or having disbonded coating or CP shielding coatings be eligible? Are there coating types that should disqualify pipe? Should some types of pipe, such as lap-welded, flash-welded, or low-frequency electric resistance welded pipe be ineligible? Should pipe where the seam type is unknown be ineligible? Why or why not?

(iv) Should pipe with significant corrosion (wall loss) be eligible for certain IM measures, or should it be replaced? Why or why not?

(v) Should anomalies be repaired similar to IM, allowed to grow to only a 10-percent safety factor[44] (§ 192.933(d)) before remediation in high population areas such as Class 2, 3 and 4 locations, or should they have an increased safety factor for remediation should these class location factors be eliminated? Why or why not?

(vi) Should pipe that has been damaged (dented) or has lost ground cover due to 3rd party activity (excavation or other) be eligible? Why or why not?

(vii) Should pipe lacking cathodic protection due to disbonded coating be eligible? Why or why not?

(viii) Should pipe with properties such as low frequency electric resistance weld (LF–ERW), lap welded, or other seam types that have a history of seam failure due to poor manufacturing properties or seam types that have a derating factor below 1.0 be eligible? Why or why not?

4b.—Should PHMSA base any proposed requirements off its criteria used for considering class location change waivers (69 FR 38948; June 29, 2004), including the age and manufacturing and construction processes of the pipe, and O&M history? Why or why not?

4c.—In the 2004 **Federal Register** notice (69 FR 38948), PHMSA outlines certain requirements pipelines must meet to be eligible for waiver consideration, including no bare pipe or pipe with wrinkle bends, records of a hydrostatic test to at least 1.25 times MAOP, records of ILI runs with no significant anomalies that would indicate systemic problems, and agreement that up to 25 miles of pipe both upstream and downstream of the waiver location must be included in the operator's IM program and periodically inspected using ILI technology. Further, the criteria provides no waivers for segments changing to Class 4 locations or for pipe changing to a Class 3 location that is operating above 72% SMYS. Should PHMSA require operators and pipelines to meet the threshold conditions outlined earlier in this document (Section 3A; ''Class Location Change Special Permits—Special Permit Conditions) or other thresholds to be eligible for a waiver when class locations change? Why or why not?

Q5—As it is critical for operators to have traceable, verifiable, and complete (TVC) records to perform IM, should operators be required to have TVC records as a prerequisite for performing IM measures on segments instead of replacing pipe when class locations change? Why or why not?

5a.—If so, what records should be necessary and why? Should records include pipe properties, including yield strength, seam type, and wall thickness; coating type; O&M history; leak and failure history; pressure test records; MAOP; class location; depth of cover; and ability to be in-line inspected?

5b.—If operators do not have TVC records for affected segments and TVC records were a prerequisite for performing IM measures on pipeline

[43] Sections involving class location requirements include §§ 192.5, 192.609, 192.611, 192.619 and 192.620.

[44] Section 192.933 has anomaly repair requirements based upon a predicted failure pressure being less than or equal to 1.1 times the MAOP.

segments in lieu of replacing pipe, how should those records be obtained, and when should the deadline for obtaining those records be?

Q6—Should PHMSA incorporate its special permit conditions regarding class location changes into the regulations, and would this incorporation satisfy the need for alternative approaches? Why or why not? (Examples of typical PHMSA class location special permit conditions can be found at *https://primis.phmsa.dot.gov/classloc/documents.htm.*)

6a.—What, if any, special permit conditions could be incorporated into the regulations to provide regulatory certainty and public safety in these high population density areas (Class 2, 3, and 4)?

Q7—For all new and replaced pipelines, to what extent are operators consulting growth and development plans to avoid potentially costly pipe change-outs in the future?

Q8—What is the amount of pipeline mileage per year being replaced due to class location changes for pipelines: (1) Greater than 24 inches in diameter, (2) 16–24 inches in diameter, and (3) less than 16 inches in diameter?

8a.—Of this mileage, how much is being replaced due to class locations changing when additional structures for human occupancy are built near clustered areas, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)?

8b.—At how many distinct locations are pipe replacements occurring due to class location changes and that involve pipe with these diameters?

8c.—What is the average amount of pipe (in miles) being replaced and cost of replacement at the locations described in question 8b. and for these diameter ranges due to class location changes?

Q9—Should any additional pipeline safety equipment, preventative and mitigative measures, or prescribed standard pipeline predicted failure pressures more conservative than in the IM regulations be required if operators do not replace pipe when class locations change due to population growth and perform IM measures instead? Why or why not?

9a.—Should operators be required to install rupture-mitigation valves or equivalent technology? Why or why not?

9b.—Should operators be required to install SCADA systems for impacted pipeline segments? Why or why not?

Q10—Should there be any maximum diameter, pressure, or potential impact radius (PIR) limits that should disallow operators from using IM principles in lieu of the existing requirements when class locations change? For instance, PHMSA has seen construction projects where operators are putting in 42-inch-diameter pipe designed to operate at up to 3,000 psig. The PIR for that pipeline would be over 1,587 feet, which would mean the total blast diameter would be more than 3,174 feet.

VII. Regulatory Notices

A. Executive Order 12866, Executive Order 13563, Executive Order 13771, 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.'' Executive Order 13771 (''Reducing Regulation and Controlling Regulatory Costs''), issued January 30, 2017, provides that ''it is essential to manage the costs associated with the governmental imposition of private expenditures required to comply with Federal regulations.'' One way to manage the costs of rulemakings is to propose new regulations that are deregulatory in nature, *i.e.* regulations that reduce the cost of regulatory compliance. PHMSA seeks information on whether this rulemaking could result in a deregulatory action under E.O. 13771, meaning that a potential final rule could have ''total costs less than zero.'' [45] 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 the 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 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 the regulations the agency should consider that would minimize any significant negative 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, including comments about compliance measures that would provide greater benefit to the human environment or any 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

[45] See OMB Memorandum M–17–21, ''Guidance Implementing Executive Order 13771, Titled 'Reducing Regulation and Controlling Regulatory Costs,' '' (April 5, 2017).

information and paperwork burdens related to this ANPRM.

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).

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Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

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