THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable Bill Shuster
Chairman
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Ranking Member of the House Committee on Transportation and Infrastructure; the Chairman and Ranking Member of the House Committee on Energy and Commerce; and the Chairman and Ranking Member of the Senate Committee on Commerce, Science, and Transportation.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable Peter A. DeFazio
Ranking Member
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Congressman DeFazio:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Chairman of the House Committee on Transportation and Infrastructure; the Chairman and Ranking Member of the House Committee on Energy and Commerce; and the Chairman and Ranking Member of the Senate Committee on Commerce, Science, and Transportation.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable Fred Upton
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Ranking Member of the House Committee on Energy and Commerce; the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure; and the Chairman and Ranking Member of the Senate Committee on Commerce, Science, and Transportation.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable Frank Pallone, Jr.
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Congressman Pallone:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Chairman of the House Committee on Energy and Commerce; the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure; and the Chairman and Ranking Member of the Senate Committee on Commerce, Science, and Transportation.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable John Thune
Chairman
Committee on Commerce, Science,
and Transportation
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Ranking Member of the Senate Committee on Commerce, Science, and Transportation; the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure; and the Chairman and Ranking Member of the House Committee on Energy and Commerce.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

THE SECRETARY OF TRANSPORTATION
WASHINGTON, DC 20590

June 8, 2016

The Honorable Bill Nelson
Ranking Member
Committee on Commerce, Science,
and Transportation
United States Senate
Washington, DC 20510

Dear Senator Nelson:

I am pleased to submit this report in response to Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112-90). Section 5 of the Act includes the requirement that the Secretary of Transportation submit a report no later than 2 years after the enactment of the Act—based on the evaluation conducted under subsection (a)—containing the Secretary's analysis and findings regarding:

> Expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
>
> With respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is the U.S. Department of Transportation (DOT) agency responsible for administering the Department's national regulatory program to assure the safe transportation of gas, petroleum, and other hazardous materials by pipeline. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operators, regulatory agencies, and the public, including through public meetings and workshops.

PHMSA is currently considering proposals to improve both hazardous liquid and gas transmission pipeline safety by expanding selected integrity management program elements, including integrity, assessment, and repair, outside of high consequence areas (HCAs).

PHMSA evaluated several alternatives for changing the current regulations with respect to defining and ways to approach changes in class location, when they occur. Alternatives considered are as follows:

> Using a single design factor for all pipeline class locations as an alternative to the current method for determining class locations.

Replacing the current sliding mile methodology for determining a class location unit by a methodology that is based on HCA Potential Impact Radius (PIR). An additional safety factor would be considered, if this method were proposed.

Expanding current class locations to include additional class locations for densely populated urban areas with buildings over four stories tall.

Using a bifurcated approach, suggested by the Interstate Natural Gas Association of America, to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines.

Retaining the current method for determining class locations but revising the regulations for addressing changes in class locations. Such changes might include alternatives to pipe replacement, retesting, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and to monitor the pipe within an integrity management process.

Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very thorough process. Class locations affect all gas pipelines and several subparts and sections of the Federal Pipeline Safety Regulations. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes.

The final report for the study, entitled Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements, is enclosed.

I have sent a similar letter to the Chairman of the Senate Committee on Commerce, Science, and Transportation; the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure; and the Chairman and Ranking Member of the House Committee on Energy and Commerce.

If I can provide further information or assistance, please feel free to contact me.

Sincerely,

Anthony R. Foxx

Enclosure

Report to Congress

Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements

Pipeline Safety, Regulatory Certainty, And Job Creation Act 2011, Section 5

April 2016
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation

Table of Contents

Executive Summary

Section 5(c) of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) (Pub. L. 112-90) requires the Secretary of Transportation to "evaluate (1) whether integrity management (IM) system requirements, or elements thereof, should be expanded beyond high consequence areas (HCAs); and (2) 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." Section 5(f) of the Act authorized the Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue regulations in accordance with the report after the conclusion of a review period. This report documents that evaluation and addresses whether IM program requirements should be expanded beyond high consequence areas (HCAs) and, specifically for gas transmission pipelines regulated under 49 Code of Federal Regulations (CFR) Part 192, whether such expansion would mitigate the need for class location designations and corresponding requirements. PHMSA conducted a class location public meeting on April 16, 2014, and requested public comments to be submitted to Docket Number PHMSA-2013-0161[1] located on the internet at regulations.gov. Public comments received on the docket were evaluated.

In October 2010 and August 2011, PHMSA published notices in the Federal Register to solicit comments on revising the pipeline safety regulations applicable to hazardous liquid and natural gas transmission pipelines including expansion of IM program requirements beyond HCAs. In general, industry representatives and pipeline operators were opposed to any expansion of HCAs and in favor of eliminating class locations on newly constructed pipelines, whereas public interest groups were in favor of expanding HCAs but against curtailing class location requirements.

PHMSA has carefully considered the input and comments. At this time, PHMSA plans to propose an approach that balances the need to provide additional protections for persons within the potential impact radius (PIR) of a pipeline rupture (outside of a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs. PHMSA, therefore, is considering an approach that would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to be applicable for non-HCA segments. For hazardous liquid pipelines, PHMSA would propose to apply these requirements for non-HCA pipeline segments.[2] For gas transmission pipelines, PHMSA would propose to apply these requirements where persons live and work and could reasonably be expected to be located within a pipeline PIR. Under this approach, PHMSA would propose requirements that

[1] On August 25, 2011, (76 FR 53086) PHMSA published in the Federal Register an Advance Notice of Proposed Rulemaking (ANPRM) titled: "Safety of Gas Transmission Pipelines" seeking comments on the need for changes to the regulations covering gas transmission pipelines. Public comments from this ANPRM are posted on Docket Number PHMSA-2011-0023 located on the internet at regulations.gov.

[2] Gas and Hazardous Liquid (HL) Notices of Proposed Rulemaking (NPRM) both protect the safety of humans in a similar manner. The difference is the environmental effects of HL versus gas releases on the environment including the effects on soils, streams, and rivers. Due to gas being lighter than air, gas rises up and does not pollute soil, streams, and rivers compared to hazardous liquids such as crude oil which is heavier than air.

integrity assessments be conducted, and that injurious anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, the other program elements of a full IM program contained in 49 CFR Part 192, Subpart O, or 49 CFR Section 195.452 (as applicable) would not be required for non-HCA segments.

The Act also required the Secretary of Transportation to evaluate if expanding IM outside of HCAs for gas transmission pipelines, as discussed above, would mitigate the need for class location requirements.

Expanding IM Requirements Beyond HCAs

Based upon findings from lessons learned, accident investigations, assessments, IM, and operations and maintenance (O&M) considerations, PHMSA is proposing through a notice of proposed rulemaking (NPRM) to apply selected IM program elements (i.e. assessments and remediation on a continuing interval) to areas outside HCAs. For gas transmission pipelines, the assessment and remediation requirements would be limited to selected areas outside HCAs identified in this report as moderate consequence areas (MCAs). This integrity assessment approach for non-HCA locations is addressed in separate NPRMs for both gas transmission and hazardous liquid pipelines.

Class Location

On August 1, 2013, PHMSA published a notice in the Federal Register (78 FR 46560) soliciting comments on expanding gas IM program requirements and mitigating class location requirements (Class Location Notice). Comments in the Class Location Notice were solicited on whether:

1. PHMSA should increase the existing class location design factors in densely populated areas with building over four stories?
2. Class locations should be eliminated and a single design factor used, if IMP requirements are expanded beyond HCAs?
3. Should there be only a single design factor for pipeline areas where there are large concentrations of populations along the pipeline; such as schools, hospitals, nursing homes, multiple-story buildings, stadiums, and shopping malls, as opposed to rural areas like deserts and farms where there are fewer people?

A class location workshop was held on April 16, 2014, to discuss this notice and comments were received from stakeholders, including industry representatives, pipeline operators, state regulatory agencies, and the public. Based on PHMSA's evaluation of written comments and stakeholder input at the workshop, PHMSA considered several alternatives for changing the current regulations with respect to defining class locations and how to approach changes in class location, when they occur, which include:

Single Design Factor

PHMSA solicited comments on the use of a single design factor for all pipeline class locations as an alternative to the current method for determining class locations. The proposal was to use a higher design factor where there are large concentrations of populations, such as schools, hospitals, nursing homes, multiple-story buildings, stadiums, and shopping malls.

The comments on the use of a single design factor were overwhelmingly negative. Commenters felt that, to mitigate class locations by going to a single design factor approach would impact too many of the existing requirements in 49 CFR Part 192, including design, construction, and operational inspections and would be complicated to implement and may result in a decrease in safety in populated areas.

Sliding Mile Based upon Potential Impact Radius

The current sliding mile methodology for determining a class location unit could be replaced by a methodology based on the HCA PIR. Some pipeline industry comments suggested this approach may have merit for new and replaced pipe instead of existing pipe. An additional safety factor would be considered if this method were proposed. One operator proposed a method similar to the PIR approach. The operator called it "the Class Location Circle" approach. The Class Location Circle would be either 300 feet in radius or the PIR of the pipeline whichever results in a larger area. Also, another operator proposed a redefinition of the class location densities over those currently found in 49 CFR Section 192.5.

Expand Class Locations

Gas transmission pipelines are currently classified as Class 1, 2, 3, or 4 locations. A Class 4 location is defined as a class location where buildings of four (4) or more stories are prevalent. Heavily developed urban areas have many buildings over four stories high. While some commenters felt that the existing class location approach should be retained and expanded to include additional class locations for densely populated urban areas with buildings over four stories tall, a majority of industry and operator commenters were against adding additional class locations. The industry representatives and pipeline operators felt that new class locations with design factors lower than the current 0.4 design factor for Class 4 locations would make it difficult to continue to supply natural gas to the newly classified areas.

Bifurcated Approach

The Interstate Natural Gas Association of America (INGAA) submitted a written request to keep the current method for existing pipelines, but add a new method using the PIR approach for new construction and replaced pipelines. This approach would utilize the HCA PIR type approach for new or replaced pipelines only and would keep the current class location definitions and applications for existing pipelines.

INGAA's bifurcated approach would allow class location changes to existing pipe including pre-Code pipe with additional operational and integrity measures, and new pipelines with a single design factor in all class locations to have additional material, construction and integrity measures.

Class Location Changes – Allow Additional IM Assessments

One alternative being considered is to retain the current method for determining class locations but to revise the regulations for addressing changes in class locations. Such changes might include alternatives in addition to pipe replacement, retesting, or de-rating, such as incorporation of IM practices to validate the condition of the pipe and monitor the pipe within an IM process. Specifically, the INGAA suggested that PHMSA consider and engage stakeholders regarding eighteen categories of standards or requirements that could be developed through rulemaking to replace the current Class Location Special Permits program. The eighteen categories suggested by INGAA are similar to the conditions PHMSA has used in granting class location special permits. Such an approach would provide regulatory certainty.

No Change

Retain the current 49 CFR Part 192 methods for determining class location (definition) and class location changes along with the requirements that correspond with those designations, including Maximum Allowable Operating Pressure (MAOP), pressure testing, operational inspections and inspection intervals.

Conclusion

Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes as population increases used for establishing MAOP and O&M surveys for existing pipelines. For new transmission pipelines, some industry groups and operators supported some type of bifurcated approach for existing and new pipelines as described above. Other commenters suggested alternatives to requirements that sometimes result in pipe replacement when class location changes.

For gas transmission pipelines, PHMSA believes the application of IM assessment and remediation requirements to MCAs does not warrant elimination of class locations. Class locations affect all gas pipelines, including transmission (interstate and intrastate), gathering, and distribution pipelines, whether they are constructed of steel pipe or plastic pipe. Class location is integral to determining MAOPs, design pressures, pipeline repairs, HCAs, and O&M inspections and surveillance intervals.[3] Class locations affect 12 subparts and 28 sections of 49 CFR Part 192 for gas pipelines. The subparts and sections are listed and discussed in Sections 3.1.2.4 and 3.7.2.2. While assessment and remediation of defects on gas transmission pipelines is an important risk mitigation program, it does not adequately compensate for other aspects of class location as it relates to other types of gas pipelines and as it relates (for all gas pipelines) to the original pipeline design and construction such as the design factor, initial pressure testing, establishment of MAOP, O&M activities, and other aspects of pipeline safety, that are based on class location. Also, there are some disadvantages to using only the PIR circle method without inclusion of class locations that use human dwelling counts or buildings within the PIR. For instance: (a) PIR approach may exclude buildings/homes for PIRs less than 660 feet, which could be impacted from a pipeline rupture and are now included in the class location unit, (b) PIR approach does not take into account pipe wall thickness, grade, seam type, testing history, or

[3] PIR could be used as an alternative to the class location spacing unit (§ 192.5(a)(1)) of 220 yards (660 feet) on either side of the pipeline used to determine class locations for new pipelines. The class location dwelling count would need to have similar numbers as defined in § 192.5 for either the current class location unit or a “PIR based” class location unit. In this way, the PIR approach could be used to define class locations in order to construct risk/design factor categories.

design factor, and (c) it may not take into consideration future development adjacent to PIR circle without requirements for future surveys. Thus, PHMSA has preliminarily determined to not eliminate the existing class location requirements. [4]

Future PHMSA Consideration of Class Location

PHMSA acknowledges that, although it has decided to not eliminate class location requirements at this time, industry raised some legitimate issues with the existing rules, or lack thereof, for implementing class location. PHMSA will continue to listen to stakeholder input and consider:

- Comments and suggested approaches submitted on the docket in response to this report; Docket Nos. PHMSA-2011-0023, PHMSA -2013-0161 and the April 16, 2014 Class Location Workshop presentations are on the below link: http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95
- More efficient and practical class location approaches that provide appropriate safety and avoid unnecessary costs such as unnecessary pipe replacement.

PHMSA will continue to study and consider if adjustments are needed to class location requirements. PHMSA will consider these issues in the context of other issues it is addressing related to new construction quality management systems (QMS) and safety management systems (SMS). PHMSA will also consider inspection findings, IM assessments, and lessons-learned from past incidents. Any changes to the definition and application of class locations in 49 CFR Part 192 will require a very thorough process. PHMSA plans to further evaluate the feasibility and the appropriateness of each alternative, continue to reach-out to all stakeholders, consider input from all sources, and consider future rulemaking if a cost-effective and safety focused approach to adjusting specific aspects of class location requirements can be developed in order to address the issues identified by industry.

[4] PHMSA did not analyze the cost. The potential pros and cons are highlighted in Section 3 of this report.

1. INTRODUCTION

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act), Section 5, requires the Secretary of Transportation to evaluate and issue a report evaluating whether IM system requirements, or elements thereof, should be expanded beyond HCAs and, with respect to gas transmission pipeline facilities, whether applying IM program requirements to these additional areas would eliminate or reduce the need for class location requirements.

In conducting the evaluation the Act required the following, at a minimum, to be considered:

1. Continued protections for public safety;
2. Continued reduction of risk in HCAs;
3. Cost of applying IM standards to pipelines outside of HCAs where operators are already conducting assessments beyond what is required under Chapter 601 of Title 49, United States Code;
4. Achievable and sustainable IM assessments and repairs with limited disruption in pipeline service;
5. Options for phasing in any extension of IM requirements beyond HCAs, including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities; and
6. The appropriateness of applying repair criteria, pressure reductions, and other special safety requirements for scheduling remediation to areas outside of HCAs.

To perform the evaluation, PHMSA solicited comments from stakeholders including industry representatives, pipeline operators, regulatory agencies, and public interest groups.

2. EXPANSION OF IM REQUIREMENTS BEYOND HCAs (The Act § 5(a)(1))

2.1 History of IM Program

2.1.1 History of Hazardous Liquid IM Program

On October 24, 1992, the Pipeline Safety Act of 1992 (Pub. L. 102-508) was enacted establishing the foundation for taking a risk-based approach to pipeline safety. [5] The law directed DOT, through the Research and Special Programs Administration (RSPA), a predecessor agency to PHMSA, to prescribe, if necessary, additional standards requiring the periodic inspection of each pipeline in high population density areas or in areas unusually sensitive to environmental damage (collectively referred to as high consequence areas or HCAs). In response to this directive, the Office of Pipeline Safety (OPS) [6] created several initiatives, some of which include the Risk Management Demonstration Program and the Systems Integrity Inspection Program. In 1999, OPS held a public meeting[7] to consider the lessons learned from

[5] Two years later, Public law 103-272 re-codified many provisions of this Act in Title 49 U.S. Code.

[6] OPS is the office within PHMSA that carries out national programs to ensure the safe, reliable and environmentally sound operation of the United States pipeline transportation systems.

[7] Federal Register (64 FR 56725, October 21, 1999).

these initiatives. The goal was to evaluate the need for additional regulations to provide greater assurance of pipeline integrity in high-density population areas, waters where a substantial likelihood of commercial navigation exists, and areas unusually sensitive to environmental damage. At this public meeting, OPS expressed its intent to incorporate a process into its regulations to validate pipe integrity in these HCAs. The resulting hazardous liquid pipeline IM regulations were implemented in two phases. The first phase was IM regulations for operators with 500 miles (or more) of hazardous liquid pipelines[8] and the second phase was for operators with less than 500 miles of hazardous liquid pipelines.[9]

2.1.2 History of Gas Transmission Integrity Management Program

Beginning in January 2000, OPS began meeting with industry groups, research institutions, gas transmission operators, state pipeline safety agencies, public interest parties, and other groups of interest to gain a clear understanding of the characteristics of a gas transmission pipeline incident in order to develop a definition of a HCA for gas transmission pipelines. A public meeting was held to solicit comments on Gas Transmission Pipeline Integrity Management in HCAs.[10] A second public meeting[11] was held to seek further information and clarification and obtain further public comments on IM concepts as they apply to gas transmission pipelines. At the second public meeting, OPS provided elements of a proposed gas transmission pipeline IM program. Subsequently, OPS published the first definitions of what defines a Gas Transmission HCA.[12] HCAs were initially defined as:

- Class 3 and Class 4 location;
- An area where a pipeline is within 660 feet (1000 feet where the pipeline is 30 inches in diameter and operates at a MAOP of 1000 psig or more) of a hospital, school day-care facility, retirement facility, prison or other facility having persons who are confined, are of impaired mobility, or would be difficult to evacuate; and
- An area where a pipeline lies within 660 feet (1000 feet where the pipeline is 30 inches in diameter and operates at an MAOP of 1000 psig or more) where 20 persons congregate at least 50 days in any 12 month period.

The definition of an HCA was finalized on August 6, 2002.[13] The only change from the January 9, 2002, definition was that for pipelines 12 inches or less in diameter and operating at an MAOP of less than 1200 psig, an HCA was an area where a pipeline is within 300 feet of a building occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. For pipelines greater than 12 inches in diameter, the distance was 660 feet and 1000

[8] Federal Register (65 FR 75378, December 1, 2000).

[9] Federal Register (67 FR 2136, January 16, 2002).

[10] Federal Register (66 FR 848, January 4, 2001).

[11] Federal Register (66 FR 34318, June 27, 2001).

[12] Federal Register (67 FR 1108, January 9, 2002).

[13] Federal Register (67 FR 50824, August 6, 2002).

feet for pipelines greater than 30 inches in diameter and operating at greater than 1000 psig MAOP.[14]

On December 17, 2002, the PSIA of 2002 was signed into law (Pub. L. 107-355). Section 14, "Risk Analysis and Integrity Management Programs for Gas Pipelines," required the Secretary of Transportation to develop and implement an IM program for gas transmission pipeline facilities. A NPRM[15] was published proposing requirements to implement Section 14 of the PSIA of 2002. These NPRM requirement areas included:

- Intervals for conducting baseline and reassessment testing;
- Consideration of pressure testing conducted prior to the final rule;
- Incorporation of issues raised by state and local authorities;
- Conducting of pressure testing in an environmentally appropriate manner;
- Operator notification to RSPA of changes to its IM program; and
- Record sharing of operator records with state interstate agents.

In this NPRM, OPS proposed a change to the definitions of a HCA. The concept of a covered segment was introduced. A covered segment was defined as the length of gas transmission pipeline that could potentially impact an HCA.[16] Previously, only distances from the pipeline centerline were discussed in relation to HCA definitions. The concept of using Potential Impact Circles, Potential Impact Zones, and Potential Impact Radii to identify covered segments, instead of a fixed corridor width, was introduced.[17]

Following the publication of the NPRM, RSPA held workshops and public meetings[18] to solicit comments on the proposed gas transmission pipeline IM regulations. The culmination of these public meetings was the issuance of the Gas Transmission Pipeline Integrity Management final rule on December 15, 2003,[19] which added Subpart O, "Gas Transmission Pipeline Integrity Management" to 49 CFR Part 192.

---

[14] The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width (referred to as the Potential Impact Radius) based on case-specific pipe size and operating pressure.

[15] Federal Register (68 FR 4278, January 28, 2003).

[16] HCA and PIR definitions can be found in 49 CFR § 192.903.

[17] The use of the PIR to define high consequence areas is a significant aspect of IM and greatly influences the notion that the existing class location approach might be outdated and might mitigate the need for class locations. That issue, and the contrast between the two approaches is discussed in Section 3 of this report.

[18] Federal Register (68 FR 6385, February 7, 2003); Federal Register (68 FR 9966, March 3, 2003); and Federal Register (68 FR 17594, April 10, 2003).

[19] Federal Register (68 FR 69778, December 15, 2003).

2.2 ANPRM: Safety of Hazardous Liquid Transmission Pipelines

In October 2010, PHMSA published an ANPRM seeking comments on revising the pipeline safety regulations applicable to the safety of hazardous liquid pipelines.[20] PHMSA stimulated feedback by asking a series of detailed questions in six (6) specific topic areas related to hazardous liquid pipelines. These topic areas included:

- Scope of the pipeline safety regulations and existing regulatory exceptions;
- The criteria for designation as a HCA;
- Leak detection and Emergency Flow Restricting Devices (EFRD);
- Valve spacing;
- Repair criteria in non-HCA areas; and
- Stress corrosion cracking (SCC).

Under each of these specific topic areas PHMSA requested responses to these questions. In response to the ANPRM, PHMSA received 24 comments which are available in the docket[21] at regulations.gov. The pipeline industry consensus was that the regulations as written were adequate. The industry asserted that significant improvement in the safety record of hazardous liquid pipelines had been made since the promulgation of IM rules and any modifications to the regulations should be limited. On the issue of repairs in non-HCA areas, industry representatives felt that assessments were being performed in non-HCA areas and that IM repair criteria would be voluntarily applied to any anomalies found in these areas.

2.3 ANPRM: Safety of Gas Transmission Pipelines

During August 2011, PHMSA published an ANPRM seeking comments on revising the pipeline safety regulations applicable to the safety of gas transmission pipelines.[22] PHMSA stimulated feedback by asking a series of detailed questions in 15 general topic areas related to gas transmission pipelines, gas gathering pipelines, and underground storage facilities. The general topic areas relating to gas transmission IM and expanding IM programs outside of HCAs in this ANPRM included:

- Whether IM requirements should be changed;
- Whether issues related to system integrity should be addressed by expanding non-IM requirements;
- Whether the definition of a HCA should be revised; and
- Whether additional restrictions should be placed on the use of specific pipeline assessment methods.

In response to the ANPRM, PHMSA received over 100 comments letters containing over 1,400 individual comments, which are available on the docket.[23] Significant and extensive comments

[20] Federal Register (75 FR 63774, October 18, 2010).

[21] Docket PHMSA-2010-0229.

[22] Federal Register (76 FR 53086, August 25, 2011).

[23] Docket PHMSA-2011-0023 found at regulations.gov.

on the topic of expanding IM were provided. The input generally fell into three broad categories:

1. Those who advocated the significant expansion of the full IM program to more pipeline segments (i.e., redefining HCAs to encompass more pipe segments, some of which advocated incorporation of critical infrastructure and/or additional class locations for urban, densely populated areas using even more stringent design safety factors than currently required by 49 CFR Part 192);
2. Design safety factors are factors that ensure the pipeline operating pressures are operated below 100 percent of the maximum pipe strength. Design safety factors are developed based upon risk to the public (number of human dwellings near the pipeline or type of dwelling – hospital, school, or nursing care facility) and for piping that may have additional operational stresses such as compressor stations, metering stations, fabrications, river crossings, and road/railroad crossings. Safety factors for the pipeline vary— Class 1, with a design factor of 0.72; Class 2, with a design safety factor of 0.60; Class 3, with a design safety factor of 0.50, and Class 4, with a design safety factor of 0.40. The lower the safety factor the stronger the pipe must be for the MAOP of the pipeline through thicker pipe and/or higher steel grades. Those who advocated that more stringent and/or more prescriptive standards be applied to existing IM requirements (in lieu of performance-based or programmatic requirements); and
3. Those who advocated that the existing IM rules were appropriate and that industry should be permitted to apply IM principles to non-HCA pipe segments in a voluntary basis.

Specifically, INGAA and a number of gas transmission pipeline operators noted that this was an opportune time for considering the next steps in IM, since baseline assessments under the current IM rules were being completed. INGAA noted its policy goal was to apply IM principles (as described in the national consensus standard ASME/ANSI B31.8S) beyond HCAs, covering 90 percent of people living near transmission pipelines by 2020 and 100 percent by 2030.[24] Similarly, TransCanada submitted information in support of INGAA's proposal, noting that by the end of 2012 the company will have assessed more than 85 percent of its U.S. pipeline mileage covering more than 95 percent of people living near their pipelines. However, TransCanada stated that it believed significant technological challenges would be encountered if IM regulations were extended to all pipeline segments as noted:

> TransCanada stated "achieving the goal of 100% population coverage is not without its challenges. This incremental mileage contains significant technical and operational challenges including; small diameter pipelines, single source feeds to customers, multi-diameter pipelines, low flow pipelines that would preclude the use of free-swimming in-line inspection tools, and station piping which contains complex geometries and excavation challenges due to nearby piping and other underground utilities. The availability of improved integrity management principles, including new technology, will be important as

[24] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America, *Safety of Gas Transmission Pipelines, Docket No. PHMSA-2011-0023*, dated January 20, 2012. http://www.regulations.gov/#!documentDetail;D=PHMSA-2011-0023-0082

> we address these hard-to-assess areas. We will continue to support and participate in R&D efforts including development of new inspection and assessment technology to facilitate this goal."

PHMSA is not proposing additional IM regulations to take the place of class locations.

2.4 Expanding IM Requirements to Areas Outside HCAs

PHMSA has carefully considered the extensive input and comments received to date and plans to propose an approach that balances the need to provide additional protections for persons within the PIR of a pipeline (but that is not a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the priority of HCAs. PHMSA, therefore, is considering an approach that would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to apply to non-HCA segments. For hazardous liquid pipelines, PHMSA would propose to apply these requirements for non-HCA pipeline segments. For gas transmission pipelines, PHMSA would propose to apply these requirements where persons live and work and could reasonably be expected to be located within a pipeline PIR. PHMSA would propose to promulgate a rule that would require that integrity assessments be conducted, and that significant anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, some of the other program elements of the IM program requirements contained in 49 CFR Part 192, Subpart O, or 49 CFR § 195.452 (as applicable) would not be mandatory for non-HCA segments.

2.4.1 Hazardous Liquid

Periodic assessments, particularly with inline inspection (ILI) tools, provide critical information about the condition of a pipeline, but are currently only required under the IMP requirements found in §§ 195.450 and 195.452. PHMSA believes that pipeline operators should be required to have the information needed to promptly detect and remediate conditions that could adversely affect the safe operation of pipelines in all areas. Accordingly, PHMSA is considering requiring operators to perform assessments of pipelines that are not already subject to the IM requirements at least once every 10 years. Currently, approximately 82,933 miles of hazardous liquid pipelines could affect HCAs, out of approximately 190,958 total hazardous liquid pipeline miles. This represents 43.4 percent of the hazardous liquid pipeline mileage in the country. PHMSA is considering requiring that integrity assessments be performed on the remaining 108,025 miles of hazardous liquid pipelines[25] every 10 years. This is less than the current 5-year interval for mandatory integrity assessments for hazardous liquid pipeline segments in HCAs.

PHMSA acknowledges that operators are already assessing pipeline mileage outside of HCAs and estimates that 90% of the total hazardous liquid pipeline mileage[26] has been assessed under

[25] The mileages are reported mileages on Operator Annual Reports during May 2014.

[26] API comment to PHMSA for the Hazardous Liquid (HL) ANPRM provided by AOPL-API in a letter dated February 18, 2011. In a survey of its member pipeline companies (covering 93,867 miles), API found that through the course of assessing HCA segments and pipelines near those segments, operators had assessed 83 percent of their non-HCA mileage. When combined with HCA mileage that had been assessed, this represents 90 percent of

IMP requirements. PHMSA estimates that approximately 87,000 miles of pipelines outside of an HCA are already being assessed in conjunction with the assessment of HCA mileage.

Since most hazardous liquid pipelines can be assessed using ILI technology, PHMSA believes that those assessments should be performed with ILI tools, unless an operator demonstrates that a pipeline is not capable of accommodating such tools and that an alternative method will provide a substantially equivalent understanding of pipeline integrity. PHMSA would also likely require that the results of these assessments be reviewed by persons qualified to determine if any conditions exist that could affect the safe operation of a pipeline; that such determinations be made promptly; and that any unsafe conditions be remediated in a schedule analogous to existing provisions for remediating HCA segments in the current IMP regulations.

Currently § 195.422 prescribes general requirements for pipeline repair procedures. For non-HCA segments, § 195.401(b) (1) requires that "whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to person or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition." PHMSA believes that more specific repair criteria are needed for hazardous liquid pipelines outside of HCAs and would:

- Define immediate repair conditions;
- Require immediate repair conditions be remediated upon discovery;
- Require operating pressures be reduced until immediate repair conditions are remediated; and
- Require non-immediate repair conditions to be remediated within 18 months of discovery.

While it is estimated that 90% of hazardous liquid pipelines are being assessed under the IM rule requirements, pipelines located outside of HCAs currently do not have to be repaired within the time frames required by the IM program rules. PHMSA is considering that defects in non-HCA pipeline segments meeting the immediate repair conditions should be repaired upon discovery, but that the time frame for remediating non-immediate repair conditions for these segments could be modified.

PHMSA believes that establishing requirements for assessing and repairing non-HCA pipeline segments is important because accidents have occurred in non-HCA segments that resulted in extensive environmental damage and enormous remediation costs.

2.4.2 Gas Transmission

Currently, Part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not located in HCAs as defined in § 192.903 and, therefore, not subject to Subpart O (i.e., pipelines that are not located in a

the total mileage for the survey respondents. PHMSA has placed this comment letter in the docket for the HL NPRM.

HCA).[27, 28] Approximately 7 percent or 20,000[29] miles out of 300,000[30] miles of onshore gas transmission pipelines are located in HCAs. However, coincident with integrity assessments of HCA segments, industry has, as a practical matter, assessed substantial amounts of onshore gas pipelines in non- HCA segments. For example, INGAA noted that approximately 90 percent of Class 3 and 4 location transmission mileages not in HCAs are presently assessed during IM assessments. This is due, in large part, because ILI or pressure testing, by their nature, assesses large continuous segments that may contain some HCA segments but that could also contain significant mileage of non- HCA segments.

INGAA members[31] have committed to perform pipeline assessments using IM principles outside HCAs so that approximately 90 percent of the people who live, work, or congregate near transmission pipelines would be covered by 2020, and 100 percent would be covered by 2030. INGAA stated that at a minimum, all ASME/ANSI B31.8S requirements will be applied, including mitigating corrosion anomalies and applying IM principles. Continuing to areas of less population density, INGAA has stated they plan to apply IM principles to pipelines covering 100 percent of the potential impact radius (PIR) population[32] by 2030.

However, given this level of commitment by INGAA, PHMSA has determined that it is appropriate to consider rulemaking that would codify requirements for certain non-HCA gas transmission pipelines to have an integrity assessment conducted on a periodic basis to monitor for, detect, and remediate significant pipeline defects and potentially hazardous anomalies. Requirements for data analysis, assessment methods, and immediate repair conditions would likely be similar to requirements for HCA segments. In order to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, PHMSA is considering an approach that would define a new term in the code: a “moderate consequence area” or MCA.[33] The definition would likely be based on the same methodology as HCAs as specified in § 192.903, but with more specific criteria, so that most persons that live or work within the PIR of a pipeline benefit from the protection of mandatory integrity assessments. MCAs would likely be used to define a subset of locations where integrity assessments are required. This approach is proposed as a less burdensome approach for operators to identify the MCAs, since

[27] Section 192.9 exempts gathering lines from Subpart O.

[28] Gas distribution pipelines are subject to an IM program as prescribed in Subpart P.

[29] Mileage is based upon natural gas annual reports for 2013.

[30] Mileage is based upon natural gas annual reports for 2013.

[31] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, “*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023.” INGAA represents companies that operate approximately 65% of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR Part 192.

[32] PIR population means pipeline mileage with people living, working, or congregating within the pipeline radius of a circle within which the potential failure of a pipeline could have significant impact on people and property. The PIR is calculated in accordance with § 192.903 based upon the pipeline diameter and MAOP. More discussion on the use of a PIR approach for determining class location can be found in Section 3.7.2.

[33] MCA definition, assessment, and remediation standards are in the notice of proposed rulemaking (NPRM) for the gas integrity verification process (Gas Rule).

gas transmission operators must already have performed the analysis in order to have identified the HCAs, or verify that they have no HCAs. In addition, the MCA definition would include locations where interstate highways, freeways, expressways, and other principal 4-lane arterial roadways are located within the PIR. This additional MCA criterion is intended to meet the intent of National Transportation Safety Board (NTSB) Recommendation P-14-1.

The above approach conforms with the INGAA commitment to conduct integrity assessments that cover 100 percent of the PIR population, as well as Congressional directives to consider effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities. PHMSA estimates that approximately 39,000 miles of pipeline would meet the MCA definition. However, PHMSA acknowledges that operators have already incurred costs where operators are already conducting assessments beyond what is required under 49 CFR Part 192. Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA would consider allowing the use of those prior assessments for non-HCA segments, provided the assessment was conducted in accordance with an integrity assessment required by 49 CFR Part 192, Subpart O. As a result, PHMSA estimates that approximately 7,400 miles of pipeline would need an initial integrity assessment (i.e., has not been previously assessed in conjunction with an HCA assessment).

PHMSA is considering requiring that pipeline segments in MCAs be assessed within 15 years and every 20 years thereafter. PHMSA believes this to be a reasonable timeframe for reassessments, given the large amount of pipeline assessments that would be required.

Currently, § 192.485 prescribes remedial measures that are required to be implemented when the pipeline has lost strength due to corrosion and § 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing rule requires that permanent repairs be made as soon as feasible. However, no specific repair criteria are provided and no specific timeframe or pressure reduction requirements are provided. PHMSA believes that more specific repair criteria based upon class location are needed for pipelines not covered under the IM rule. PHMSA would also propose to require that specific conditions (i.e., repair criteria) be remediated, to identify the timeframe within which repairs must be made, and to require a reduction of operating pressure for conditions that present an immediate hazard. Further, PHMSA believes that such repair criteria should be similar to, and based upon, comparable repair criteria for HCAs, but that time frames for non-immediate conditions be relaxed. PHMSA believes that establishing these non-HCA segment repair conditions are important because, even though they are not within the defined high consequence locations, they could be located in populated areas and are not without consequence. For example, as reported by operators in the 2013 annual reports, while there are approximately 20,000 miles of gas transmission pipe in HCA segments, there are approximately 65,000 miles of pipe in Class 2, 3, and 4 populated areas. PHMSA believes it is prudent and appropriate to include criteria to assure the timely repair of potentially hazardous pipeline defects in non-HCA segments. These changes would ensure the prompt remediation of anomalous conditions, while allowing operators to allocate their resources to HCAs on a higher priority basis. In addition, PHMSA proposes to prescribe more explicit requirements for *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCC direct assessment, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects. Cracking defects would need prescribed evaluation criteria to establish any required replacements, repairs, and future reassessments.

PHMSA believes that establishing requirements for non-HCA segment integrity assessments and associated repair conditions is important because, even though such segments are not within defined HCA locations, they could be located in populated areas and incidents would still have serious consequences. These changes would facilitate the prompt identification and remediation of potentially hazardous defects and anomalous conditions that could potentially impact people, property, or the environment, commensurate with the seriousness of the defect, while allowing operators to allocate their resources to high consequence areas on a higher priority basis. Which selected IM requirements should apply to MCAs would be a topic PHMSA would explore and seek comment on.

2.4.3 Notice of Proposed Rulemaking

In accordance with the Act, Section 5(f), two NPRM proposals recently published to address 49 CFR Part 192 and Part 195, as described in the above paragraphs. PHMSA believes that this approach for expanding selected IM program elements to locations beyond HCAs:

1. Represents a significant enhancement to public safety;
2. Continues to emphasize the priority and importance of HCA;
3. Does not require operators to incur costs where operators have already conducted assessments beyond what is currently required under Chapter 601 of Title 49, United States Code;
4. Is achievable and sustainable, and minimizes disruptions of pipeline product deliveries to the public and industrial customers;
5. Represents an effective and efficient means for decreasing risks to persons living or working in proximity to pipeline facilities; and
6. Applies repair criteria (including pressure reductions and special requirements for scheduling remediation) that are appropriate to areas that are not HCAs.

3. DOES EXPANSION OF IM BEYOND HCAs MITIGATE THE NEED FOR CLASS LOCATIONS? (The Act § 5(a)(2))

With respect to gas transmission pipeline facilities, the Act requires the Secretary of Transportation to evaluate whether applying IM program requirements to additional areas would mitigate the need for class location requirements. Section 2 of this report addresses PHMSAs evaluation and approach for applying selected IM program elements (i.e., assessment, remediation, and continuing reassessment programs) to additional pipeline segments that are outside HCAs. This section evaluates whether such expansion of IM requirements might mitigate the need for class location requirements.

3.1 Class Locations (Background)

3.1.1 History of Class Locations

Class locations were an early method of differentiating areas along natural gas pipelines based on the potential consequences of a postulated pipeline failure. The class location concept pre-dates Federal regulation of gas transmission pipelines. Class location designations were previously included in ASA B31.8-1968 version of the "Gas Transmission and Distribution Pipeline System." which is now known as the ASME International Standard, ASME B31.8 "Gas Transmission and Distribution Pipeline Systems." The class location definitions incorporated into 49 CFR Part 192 were initially derived from the ASA B31.8 class location designations (hereafter referred to as ASME B31.8).

The Natural Gas Pipeline Safety Act of 1968 (NGPSA) (Public Law 90-481), §3(a) required that OPS adopt interim minimum Federal safety standards for pipeline facilities and the transportation of gas based on State regulations. These interim standards, based on ASME B31.8, were adopted by OPS and temporarily incorporated into the Code of Federal Regulations as Part 190.[34] The NGPSA further required that OPS develop comprehensive minimum Federal safety standards for gas pipeline facilities and for the transportation of gas.

The first regulatory definitions of class locations were published on March 24, 1970.[35] These definitions, with some modifications, still apply today. The minimum Federal standards were promulgated as 49 CFR Part 192 with an effective date of March 13, 1971,[36] with class location definitions being defined in Section 192.5. These definitions met the original ASME B31.8 definitions for Class 1 through 3 locations but added an additional Class 4 definition. The class location is determined by counting the number of dwellings within 220 yards (660 ft.) on either side of the pipeline centerline for a "sliding mile[37]." Table 3-1 compares the definition of class

[34] Federal Register (33 FR 16500, November 13, 1968).

[35] Federal Register (35 FR 5012, March 24, 1970).

[36] Federal Register (35 FR 13248, August 19, 1970).

[37] The "sliding mile" is a term that counts the number of dwellings in a mile distance (moving or sliding mile) to determine the number of dwellings in the class location unit. Section 192.5 of the Gas Code takes segments out of the "sliding mile" for class location determination, if there are no other dwellings in the remaining portions of the mile (Cluster).

locations in Part 192 with the original and current definitions in ASME B31.8. Pictorial examples of each Class location are shown in Figures 3-1 through 3-4.

Table 3-1

Historical Comparison of Class Location Unit[38] Definitions

Class Location	Part 192 Definition	Original and Current ASME B31.8 Definition[39]	Current ASME B31.8 Definition[40] for "Class Location Changes"
1	Any class location unit that has 10 or fewer buildings intended for human occupancy	0 to 10 Buildings Intended for Human Occupancy (BIHOs)	11 to 25 BIHOs
2	Any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.	11 to 45 BIHOs	26 to 45 BIHOs; (MAOP = 0.8 x test pressure but < 72% of specified minimum yield strength (SMYS)). 46 to 65 BIHOs; (MAOP = 0.667 x test pressure but < 60% of SMYS).
3	Any class location unit that has 46 or more buildings intended for human occupancy.	46 or more BIHOs	66 or more BIHOs
3	An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.).		Pipelines near places of public assembly or concentrations of people, such as churches, schools, multiple dwelling unit buildings, hospitals, or recreational areas of an organized nature in Location Class 1 or 2 shall meet requirements for Location Class 3.
4	Any class location unit that has where buildings of 4 or more stories above ground are prevalent.	NA	Where multistory buildings are prevalent

38 As defined in § 192.5, a "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

39 ASME B31.8-2010, Section 840.2.2 outlines class location definitions for Design, Installation and Testing. ASME B31.8 is presently an industry consensus standard. 49 CFR Part 192 contains the Federal regulations for class location in §§ 192.5, 192.609 and 192.611.

40 ASME B31.8-2010, Section 854 outlines class location definitions for operating and maintenance (O&M) procedures. ASME B31.8-2007 is currently invoked by reference in Part 192. The definitions provided here were also in the ASME B31.8-2003 version.

Figure 3-1: Class 1 location (10 or less BIHOs) [41]

Figure 3-2: Class 2 location (>10 but fewer than 46 BIHOs)

[41] The red line in each pictorial represents the approximate location of the pipeline in a right-of-way (ROW).

Figure 3-3: Class 3 location (46 or more BIHOs and well defined area - playground)

Figure 3-4: Class 4 location (Buildings with 4 or more stories prevalent)

3.1.2 Purpose of Class Locations

Class locations are used in numerous areas of Part 192 to implement a graded approach to providing more conservative safety margins and more stringent safety standards commensurate with the potential consequences based on population density near the pipeline. The most basic and earliest use of class location focused on the design (safety) margin. As standards and regulations evolved, the use of class locations was included for many regulatory requirements in the same manner, i.e., apply greater and more rigorous safety requirements commensurate with the class location.

3.1.2.1 Design (Safety) Margin

Design factors, which are used in the pipeline design formula (§ 192.105) to determine the design pressure for steel pipe, and which, generally, reflect the MAOP based upon a percentage of the specified minimum yield strength (SMYS) that the pipeline can be operated, are based on class locations. These design factors, from §192.111, "Design factor (F) for steel pipe", from §192.620, "Alternative maximum allowable operating pressure (AMAOP) for certain steel pipelines", and ASME B31.8 are shown in Table 3-2.

Table 3-2

Design (Safety) Factors for Steel Pipe Based on Class Location

Class Location	B31.8 Design Factors	Part 192 Design Factors - §192.111[42]	Alternative MAOP Design Factors - §192.620
1	0.8[43] /0.72[44]	0.72	0.8
2	0.6	0.6	0.67
3	0.5	0.5	0.56
4	0.4	0.4	Not Applicable

Design safety factors are used in engineering calculations (Barlow's Formula) to calculate the design pressure and MAOP of a steel pipeline. Other pipe characteristics needed in using Barlow's Formula would be the pipe: diameter, wall thickness, strength (grade), seam factor/type, operating temperature, and class location. The calculation of the design pressure for steel pipe is outlined in § 192.105.

---

[42] The design factors for Class 1, 2, 3 and 4 locations are in § 192.111 of the Code and are used to establish a design pressure in Section 192.105 for determining the pipeline segments maximum allowable operating pressure (MAOP). Design factors were an original part of the Code when it was established in late-1970. Design factors are used so that heavier wall pipe is used in areas of greater population.

[43] In ASME B31.8, Class 1, Division 1 is pipelines operating at 72% SMYS to 80% SMYS.

[44] In ASME B31.8, Class 1, Division 2 is pipelines operating at less than 72% SMYS.

Table 3-3 **Design (Safety) Factors for Steel Gas Pipeline - International**						
Class Location	**United States §192.111**	**United States Alternative MAOP §192.620**	**United Kingdom**[45]	**Canada**[46]	**Australia**[47]	**ISO**[48] **13623**
1	0.72	0.8	0.72/0.5	0.8	0.80[49]	0.83[50]
2	0.6	0.67	0.72/0.5	0.72	0.80	0.77
3	0.5	0.56	0.5/0.3	0.56	0.80	0.67
4	0.4	Not Applicable (NA)	0.3	0.44	0.80	0.55
5	NA	NA	NA	NA	NA	0.45

Table 3-3 compares design factors used for determining the MAOPs of gas pipelines in Australia, Canada, the United Kingdom and the United States. The above comparison in Table 3-3 shows that all of these countries use 0.72 to 0.80 (which is the least conservative design factor) in sparsely populated and rural areas. Canada and the United States use a similar approach for design safety factors in all class locations. Canada requires class location surveys, increased pipe safety measures, and pipe upgrades to the new design safety factor when the population density increases to new class locations – mainly when the class changes from 1 to 3 or 2 to 4. Canada's approach to class location changes is similar to the United States approach. The United Kingdom uses a pipeline design system for new pipelines based

[45] Class locations in the United Kingdom are called "location class 1 through 3" and are based upon risk assessments.

[46] Canada uses a class location designation similar to the United States combination of §§ 192.111 and 192.620. Canada requires class location surveys, pipe safety measures, and pipe upgrades to the new design safety factor when the population density increases to new class locations – mainly when the class changes from 1 to 3 or 2 to 4.

[47] Australia uses a class location designation of R1 (rural), R2 (semi-rural), T1 (residential), and T2 (high rise) which are similar to the United States Class 1, 2, 3, and 4 designations.

[48] The International Standard Organization (ISO) is an international code similar to ASME B31.8 for gas pipeline design, construction, and O&M.

[49] The Australian code would require increased pipe thickness based upon a review of operational threats in both rural and residential areas. A pipeline with a wall thickness of 8.02 millimeters may require a thickness of 11.8 millimeters after an engineering analysis of safety threats such as: pressure containment, penetration resistance, critical defect length, stress and strain, running fracture, special construction criteria, constructability of the pipeline, and ability to achieve adequate fatigue life.

[50] ISO 13623 class 1 location is for tundra and desert areas.

upon 0.3 or 0.5 for pipelines using "proximity pipe" (i.e. pipe having a nominal wall thickness less than 19.1 millimeters (0.752 inches)). The United Kingdom uses a higher design factor but not exceeding 0.72, when justified by a risk analysis as part of a safety evaluation. Australia, which has significantly smaller pipe diameter infrastructure than the United States, uses a starting design factor of 0.80 for all class locations, but requires a pipeline threat study along the pipeline route and location specific design factors based upon the threats (population density, third party damage, external loads, etc.) to the pipeline. The pipeline operator would have to identify the controlling load at any location along the pipeline and to adjust the pipeline thickness (upwards) to a value sufficient to control that additional load.

3.1.2.2 Test Pressure to Establish Maximum Allowable Operating Pressure

For steel pipelines operated above 100 psi, §192.619, "Maximum allowable operating pressure: Steel or plastic pipelines" specifies the test pressure as a multiple of MAOP. Test factors are based on class location and are shown in Table 3-4.

Table 3-4
Test Pressure Factors to Establish MAOP for Steel Pipelines

Class location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14	Alternative MAOP (80% SMYS) § 192.620
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.50
3	1.4	1.5	1.5	1.50
4	1.4	1.5	1.5	Not Applicable

3.1.2.3 Mainline Block Valve Spacing

Each gas transmission line, other than offshore segments, must have sectionalizing block valves. The spacing for the valves is based on the class location, as specified in §192.179, "Transmission line valves." Each point on the pipeline must be no more than the spacing shown in Table 3-5.

Table 3-5 Mainline Block Valve Spacing Based on Class Location	
Class Location	**Block Valve Spacing**
1	10 Miles (20 miles between valves)
2	7 ½ Miles (15 miles between valves)
3	4 Miles (8 miles between valves)
4	2 ½ Miles (5 miles between valves)

3.1.2.4 Various Other Requirements

In addition to design factors, MAOP, test pressure, and valve spacing, the use of class locations is deeply embedded in 49 CFR Part 192 for other requirements related to design, construction, operation, and maintenance, either directly or indirectly. To discontinue or significantly alter the existing usage of class locations would impact 12 of the 16 subparts and 28 sections of these subparts contained in 49 CFR Part 192. Multiple sections within those subparts that would be impacted due to a class location change are as follows:

- § 192.5 – Class Locations
- § 192.8 – How are onshore gathering lines and regulated onshore gathering lines determined?
- § 192.9 – What requirements apply to gathering lines?
- § 192.65 – Transportation of pipe
- § 192.105 – Design formula for steel pipe
- § 192.111 – Design factor (F) for steel pipe
- § 192.123 – Design of plastic pipe
- § 192.150 – Passage of internal inspection devices
- § 192.175 – Pipe-type and bottle-type holders
- § 192.179 – Transmission line valves
- § 192.243 – Nondestructive testing – girth welds
- § 192.327 – Depth of cover
- § 192.485 – Remaining strength and remedial measures
- § 192.503 – General requirements
- § 192.505 – Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS

- § 192.609 – Change in class location: Required study
- § 192.611 – Class change: Confirmation/revision of MAOP
- § 192.613 – Continuing surveillance
- § 192.619 – MAOP determination
- § 192.620 – Alternative MAOP
- § 192.625 – Odorization
- § 192.705 – Patrolling
- § 192.706 – Leakage surveys
- § 192.707 – Line Markers
- § 192.713 – Permanent field repairs of imperfections/damages
- § 192.903 – High Consequence Area – Method 1
- § 192.933 – Integrity assessments of anomalies
- § 192.935 – What additional Preventive and Mitigative (P&M) measures must an operator take?

In addition, multiple code sections within the subparts would be indirectly impacted.

3.1.2.5 Changes in Class Location Due to Population Growth

A class location can change as population grows and more people live or work near the pipeline. When a class location changes and the MAOP is not commensurate with the present class location, current regulations require that pipeline operators either:

- Reduce the pipe's MAOP to reduce stress levels in the pipe;
- 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
- Where the class location is changing only one class rating (one class bump), such as from a Class 1 to Class 2 or Class 2 to 3 location, the code requires a pressure test at a higher test pressure, if the pipeline segment has not previously been conducted at the higher pressure[51], see § 192.611. In this example case the pipeline segment would not require change out with new pipe, but the existing design factor of 0.72 for a Class 1 location would be acceptable for a Class 2 location.

It is this requirement to change-out the pipe, re-pressure test, or de-rate pipe to a lower MAOP when population growth occurs that is one of the most significant reasons that operators strongly advocate eliminating class locations. Operators 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. PHMSA acknowledges that the class location change regulation predated development

[51] For a Class 1 to Class 2 location change to meet § 192.611, the pipeline segment would require a pressure test to 1.25 times the MAOP for 8 hours. The pressure test would allow the MAOP for the existing pipeline segment to be 0.8 times the test pressure for a Class 1 to Class 2 location change.

of modern pipeline inspection technology such as inline inspection, above ground surveys, and modern integrity management processes.[52]

At the time, 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. Also, the operator would need to use inspection technology to ensure the pipe has the correct wall thickness, strength, seam condition, toughness, no cracking or corrosion in the pipe body or seam, and a pipe coating that has not deteriorated or shields cathodic protection currents or allows corrosion or cracking issues such as stress corrosion cracking.

Under current pipeline safety regulations, an operator may have to replace pipe if a population increase triggers a change in class location. Operators may remove some pipe and pipe coatings that are in good condition. In some circumstances, replacing a line in good condition may not necessarily make the public safer and could divert maintenance resources from correcting more imminent threats to integrity. In many cases the pipeline may be in good "condition," but it does not have the strength requirements that add that extra level of safety for the higher population density area and the MAOP of the pipeline.[53]PHMSA acknowledges that application of modern IM assessments and processes might be an alternative to pipe change-outs as a logical outgrowth of the implementation of the integrity management rule. PHMSA further acknowledges that its approach to requiring integrity assessments to a significant portion of non-HCA pipe could further support consideration of such changes. PHMSA also is concerned that some of the issues that result in pipeline failures are pipe material, pipe seam, pipe toughness, coating quality, construction practices, and operational maintenance threats that are not properly assessed and mitigated by operators,[54] whether due to lack of technology or other causes.[55]

[52] Both the Canadian and Australian natural gas pipeline codes require a review and possible change-out of pipe, lowering of MAOP's, relocation of the pipeline, or assessment and mitigation of threats to the safe operation of the pipeline when the population density increases near the pipeline.

[53] The 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 (additional dwellings for human occupancy) from one-level to a higher level there are cut-offs 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.

[54] PHMSA has met with operators constructing new pipelines on several occasions to discuss issues found during inspection. In an effort to reach out to all member of the pipeline industry, PHMSA hosted a 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. A workshop to address distribution pipeline construction was held in April 2010. http://primis.phmsa.dot.gov/construction/index.htm

3.1.2.6 Class Location Change Special Permits

Operators have applied for special permits (a type of limited regulatory waiver) to prevent the need for pipe replacement or pressure reduction after a class location changes. Based on certain operating safety criteria and periodic integrity evaluations, PHMSA has approved about 15class location special permits.'[56] As population growth has occurred, resulting in class location changes in areas where the operator, through modern integrity assessment techniques believes the pipe is in sound condition, PHMSA began to receive more requests for class location special permits.

Provided the operator submits an acceptable application for a special permit,[57] and provided certain conditions are met, PHMSA may consider waiving compliance with the confirm or revise requirements following a class location change for specific natural gas transmission pipeline segments. If granted, the special permit allows the operator to continue to operate each special permit segment at its current MAOP based on the previous class location. The typical considerations for an operator to receive a special permit that waives the class location requirements were published in the Federal Register.[58] Figure 3-5 provides a sample of a portion of the criteria for approving class location change special permits. The complete class location review table and criteria is available online at:

http://primis.phmsa.dot.gov/classloc/docs/ClassChangeWaiverCriteria.pdf.

Figure 3-5 outlines considerations for "probable acceptance" of a class location special permit based on pipelines that were constructed with post-1980 materials and construction practices, and that have been continually operated and maintained using post-1980 operating and maintenance practices. Most class location special permit applications received by PHMSA

---

[55] In 2012 on gas transmission pipelines there were a reported 112 incidents. The incidents were as follows: (1) material/weld/equipment failure – 47 incidents (42%), (2) corrosion – 25 incidents (22%), (3) excavation damage – 12 incidents (11%), (4) other outside force damage – 6 incidents (5%), (5) incorrect operation – 5 incidents (5%), (6) natural force damage – 6 incidents (5%), and (7) all other causes – 13 incidents (11%).

[56] The special permit conditions were implemented to mitigate the causes of gas transmission incidents (serious and significant). The special permit conditions were designed to require the operator to conduct additional inspections and mitigate integrity issues on the special permit pipeline segment. The conditions are based upon the type threat. The conditions are more heavily weighted on identifying: material, coating and girth weld issues, pipe wall loss, depth of pipe cover, third party damage prevention such as marking of the pipeline and pipeline right-of-way patrols, pressure tests and documentation, data integration of integrity issues, and reassessment intervals.

[57] Administrative work for a special permit to prepare annual reports and 5-year renewals which would be approximately 80 hours a year – at $150/hour = $12,000 per year. PHMSA has not developed an information collection process on the administrative costs for a special permit approval, but we have estimated, based on subject matter expert (SME) input that it would cost an operator approximately 200 labor hours and for a 30-inch diameter class location special permit would save the operator approximately $3,000,000 per mile in capital costs.

[58] 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).

have been for pipeline segments with pre-Part 192 Code pipe materials, coatings and construction techniques (pre-1970). The criteria and approach of evaluating and possibly approving class location special permits was for PHMSA to evaluate technical methods in the form of special permit conditions that could be used to maintain safety in these class location change areas. PHMSA has gotten a majority of class location special permit requests from pipeline operators for pipeline segments in the “possible acceptance” and “requires substantial justification” criteria areas.

Criteria for Class Location Change Waivers — OPS Guidelines

CRITERIA	PROBABLE ACCEPTANCE	POSSIBLE ACCEPTANCE	REQUIRES SUBSTANTIAL JUSTIFICATION
CLASS LOCATION			
Class Location Change	1 to 2 or 2 to 3	1 to 3	
PIPE DESIGN AND CONSTRUCTION			
Pipe Manufacture	Pipe Manufactured and installed in 1980[1] or later.	Pipe Manufactured and installed prior to 1980.	LF-ERW, DC-ERW, EFW, furnace lap welded pipe, pipe manufactured prior to 1954, pipe of unknown manufacturing process, or pipe known to contain manufacturing defects that could lead to failure (based on manufacturer and year of manufacture).
Pipe Material	Welded steel pipe with toughness meeting the current requirements of ASME B31.8 or pipe of known toughness.[2]	Pipe of low or unknown toughness where the operator has addressed this risk in their integrity management plan.	Pipe other than steel, pipe installed with mechanical joints, or steel pipe of unknown toughness.
Design Stress	Less than or equal to 72% of SMYS.	Up to 80% SMYS for grandfathered systems for Class 2.	
Pipe Girth Welds	Records exist[3] that demonstrate that the girth welds were volumetrically inspected during construction.	At least 1% of girth welds in the waiver location have been excavated and volumetrically inspected following construction.[4]	No radiographic inspection either during of after construction or welds made using oxy-acetylene welding process.
Pipe Coating	FBE, Multi-layer Epoxy	Polyethylene Tape, Coal Tar	Other coating materials.

[1] 1980 was selected as a year after which there is a high degree of confidence that line pipe manufactured in accordance with the requirements of API-5L is free of manufacturing defects that could fail in service. Pipe manufactured prior to 1980 may also be acceptable. OPS will consider revising this date to an earlier date if supported by the vintage pipe study currently being completed by industry.
[2] Pipe purchased to a technical specification that specified a minimum toughness requirement is considered pipe of known toughness.
[3] Records could include purchasing or other records, actual NDE reports or radiographs are not required.
[4] This post construction girth weld volumetric inspection is not required to be evaluated to new construction acceptance criteria. They should be evaluated for evidence of any flaws that would increase the likelihood of a failure as well as any gross construction defects that limit the load carrying ability of the girth weld.

June 30, 2004 — Page 4 of 10

Figure 3-5: Sample Class Location Waiver Criteria

3.2 ANPRM: Safety of Gas Transmission Pipelines

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) to seek comments on revising the pipeline safety regulations applicable to the safety of gas transmission and gas gathering pipelines. At that time, PHMSA requested comments on whether existing HCA criteria should be revised to potentially include more mileage or whether IM program requirements should be strengthened or expanded beyond the HCAs.[59]

Some comments received in response to that ANPRM directly relate to whether the need for class locations is mitigated by expansion of HCAs. The comments received on this topic are summarized as follows:

From State Representatives:

The National Association of Pipeline Safety Representatives (NAPSR) suggested that PHMSA eliminate IM requirements and instead require all transmission pipelines to meet Class 3 and 4 location requirements. NAPSR suggested that alternatively, PHMSA should revise HCA criteria to include all Class 3 and 4 locations and segments that could affect critical infrastructure.

The Jersey City, New Jersey Mayor's office submitted a petition for rulemaking dated March 15, 2012, contending that the current class location system "does not sufficiently reflect high density urban areas, as the regulations fail to contemplate either (1) the dramatic differences in population densities between highly congested areas and other less dense class 4 locations, or (2) the full continuum of population densities found in urban areas themselves." Based on this, Jersey City petitioned PHMSA to add three (3) new class locations, which would be defined as follows:

- A Class 5 location is any class location unit that includes one or more building(s) with between four and eight stories; (design factor - 0.3);
- A Class 6 location is any class location unit that includes one or more building(s) with between 9 and 40 stories; (design factor - 0.2); and
- A Class 7 location is any class location unit that includes at least 1 building with at least 41 stories. (design factor - 0.1)

The Alaska Natural Gas Development Authority stated that their experience has shown that improved pipeline design and construction requirements are needed to assure pipeline integrity. The Authority also commented that design requirements need to accommodate likely changes in class location, noting that explosive growth in some Alaska areas has resulted in certain class locations rapidly changing from Class 1 to Class 3 locations.

From the Public:

A comment from the public suggested that PHMSA revise the IM requirements to potentially include more mileage (e.g., include entire Class 3 and 4 area in lieu of only the potentially impacted area inside Class 3 & 4) and critical infrastructure. The commenter further stated that PHMSA should expand IM principles to non-HCA areas, improve public awareness and involvement in HCAs, make maps publicly available, redefine class locations for high population areas, clarify Class 4, and establish a Class 5.

The same commenter suggested that IM plans for densely populated areas (Class 4) and for a new Class 5 encompassing cities with population greater than 100,000, be developed in

[59] Federal Register (76 FR 53086, August 25, 2011).

consultation with local emergency responders. The commenter further suggested that these plans should be available for review during the Federal Energy Regulatory Commission's environmental impact study and should be reviewed with local authorities.

3.3 Notice of Inquiry: Class Location Requirements

3.3.1 History leading up to Request for Comments on Class Location Regulations

In August 2013, PHMSA solicited comments on whether expanding IM requirements would mitigate the need for class locations.[60] Important questions relevant to this issue include:

1. Should PHMSA increase the existing class location design factors in densely populated areas where building are over four stories?
2. Should class locations be eliminated and a single design factor be used, if IM requirements are expanded beyond HCAs?
3. Should there be only a single design factor for areas where there are large concentrations of populations, such as schools, hospitals, nursing homes, multiple-story buildings, stadiums, and shopping malls, as opposed to rural areas like deserts and farms where there are fewer people? If so, how should a single design factor be used?

3.3.2 Summary of Comments Received on Need for Modifying Class Locations

PHMSA received 30 comment letters.[61] Commenters provided a wide range of input. There was no clear consensus on the approach that should be taken among stakeholders or among individual industry stakeholders. A high level summary of input received is shown in the bulleted list below.

Commenter	Summary of Comments
From Industry:	• Keep class locations intact for existing pipelines. • Allow a PIR approach to be used for new pipelines and when class locations change. • Class locations are imbedded in regulations and adopting a single design factor approach would be too complicated to implement. • Stakeholders need to be involved before any rulemaking is made.
From American Gas Association (AGA):	• Allow operators to choose the method for design factors, existing class locations or PIR (HCA method).
From American Petroleum Institute (API):	• Without class locations it is not possible to determine regulatory status of gathering lines.

[60] Federal Register (78 FR 46560, August 1, 2013).
[61] Comments are available on Docket PHMSA-2013-0161.

Commenter	Summary of Comments
From APGA:	• Limit to pipelines operating at $\geq$ 30% SMYS. • Revise the definition of a transmission pipeline.
From INGAA:	• IM should be extended beyond HCAs. However, if PHMSA decides to extend IM, it must examine the effects of such a change on other sections of the pipeline safety regulations. • Allow the use of either existing method for determining Class locations or PIR method. • Revise certain operation and maintenance requirements that may no longer be necessary given new technology and integrity management activities.
From NAPSR:	• Class locations apply to much more than integrity management. • They apply to design, such as valve spacing, whether that valve is 10 miles away or 2 miles away. • They also apply to odorization and operations, leak surveys, patrolling. • Class locations are a much broader concept than just integrity management, so we do have concerns on that.
From the Iowa Utilities Board:	• Keep existing class locations. • Add additional safety to buildings outside small radius PIRs.
From the Iowa Assoc. of Municipal Utilities:	• New regulations would impose new and significant costs to operators of small diameter, low pressure pipelines. • Revise the definition of transmission pipeline.
From Pipeline Safety Trust:	• Supports applying IM beyond HCAs. • Expand class location definitions. • Strengthen existing IM rule.

3.4 Pipeline Advisory Committee Meeting

A meeting of the Gas and Liquid Pipeline Advisory Committees was held on February 25, 2014. At that meeting PHMSA updated the committees on Section 5 of the Pipeline Safety, Regulatory

Certainty, and Job Creation Act of 2011. Below is a summary of significant comments provided by members of each committee. The transcript is available on the docket.[62]

Public:

To make a change from class locations would involve a major effort by PHMSA. It would to take a lot of resources to accomplish. It would be a time consuming process and that message needs to be made in the report to Congress. There is some strength in IM over class locations; however, there are also some weaknesses.

NAPSR:

NAPSR supports the current class location framework and recommends that HCA definition be expanded to cover Class 3 and 4. NAPSR believes operators still do not understand IM and do not effectively implement it.

INGAA:

The original class location definitions in B31.8 were intended to provide an increased margin of safety for locations of higher population density. INGAA is committed to extending IM beyond HCAs. IM is a much better risk management tool than class locations and INGAA desires to apply integrity management because it's much more sophisticated and deliberate and intensive and successful than class locations. Where does it make sense to get rid of pipe replacement? This was part of the cost/benefit justification of the IM rule in 2003. To change the class location criteria for existing pipe would be extremely problematic for everybody and it is not worthwhile. INGAA supports developing a standard for new construction based on an IM approach (PIRs and HCAs), without applying it retroactively to existing pipe. Such an approach would still require a rewrite of the code.

AGA:

AGA does not support the revision and replacement or complete removal of class locations or the addition of new class locations without fully evaluating the impact (both to the operators and their systems) of the many code sections that would require substantial revision. AGA supports the development of a parallel approach, such as the IM PIR method, to alleviate pipeline replacement or pressure reductions when class locations change. AGA members encourage PHMSA to fully develop and understand the potential impact of expanding IM prior to any attempt to eliminate or modify the current class location methodology.

Industry – Pipeline Operators:[63]

Thirty to forty percent of annual budget is spent on class location changes when that pipe is not what needs attention. When we run ILI tools through those pipelines, those are not the areas that we would be out repairing based on those results. Industry believes that the effect of the rules that apply when class location changes is to divert resources to activities that, in industry's view,

---

[62] Docket No. PHMSA–2009-0203 can be downloaded from: regulations.gov.

[63] Pipeline operators comments in addition to the trade organizations listed above can be reviewed on Docket PHMSA-2013-0161 at regulations.gov.

do not benefit public safety.[64] IM is superior to existing rules for dealing with class location changes. That is the right path forward. Class locations establish a baseline for the construction of new pipelines and makes construction of new pipelines easier. Using class locations in combination with HCAs is an optimal hybrid system that would work.

3.5 Class Location Workshop

On April 16, 2014,[65] 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 of PHMSA, the National Energy Board of Canada (NEB), NAPSR, pipeline operators, industry groups, and public interest groups. Summaries of those presentations are provided below.[66]

PHMSA:

The presentations made by PHMSA described the purpose of class locations and integrity management HCAs, giving examples of how the two methods are applied to gas transmission pipelines. A brief discussion was given on candidate alternatives to class locations. (These alternatives are discussed in Section 3.7 of this report.)

***National Energy Board of Canada**:*

The representative of the NEB compared the Canadian approach to class locations to how they are applied in the United States through the Code of Federal Regulations. However, this did not represent an official NEB position on class locations. The Canadian Standards Association standard number CSA Z662 is the Canadian equivalent to 49 CFR Parts 192 and 195 for the design, operation and maintenance of gas and oil pipelines, respectively. He expressed the view that the Canadian class location rules could be "creatively misinterpreted" and were not as prescriptive as the 49 CFR 192.5 requirements. There were conflicting definitions within CSA Z662 for the same class location designation, and the Canadian class location designation might not consistently represent failure consequences.

NAPSR:

NAPSR stated that the safety management system approach being developed is a "holistic" approach that takes into account NAPSR's concerns with IM. The presentation focused heavily on the impact of expanding IM program requirements to pipelines in rural areas that are inspected by state regulators. The presenter pointed out that PHMSA provides no financial support for state inspections in rural areas and that rulemaking should be prompt to minimize industry and regulatory confusion and allow for focused training.

Iowa Utilities Board:

Iowa Utilities Board indicated that eliminating class locations would require a major rewrite of 49 CFR Part 192, O&M manuals, revisions to state laws and regulations, and revisions of

[64] Note: The commenter did not provide specific details or examples.

[65] Federal Register (79 FR 16421, March 25, 2014).

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

standards that include class location. Adding additional class locations has similar burdens as eliminating them. Considerations included:

- If the design factor for additional class locations is lower than the current design factor for Class 4 location, how will gas supply be impacted?
- For low pressure, small diameter pipelines with PIRs less than 660 feet, or 300 feet for identified sites, class locations provides more safety. For PIRs greater than 660 feet, class locations may provide less safety.
- If PHMSA applies IMP requirements to all Class 3 and 4 locations, it should allow operators to determine class location using either the current method or the PIR approach. If class location is based on the PIR approach, should an additional safety factor be applied to account for consequences outside of the PIR, as occurred in San Bruno, CA?

INGAA:

INGAA considered that the current requirements for class location change are resulting in the replacement of good pipe. The special permit process is onerous,[67] essentially eliminating it as an option. The special permit process should be embedded into the Code. An alternative to the current class location determination should be allowed for new construction. [68] An alternative would be to integrate with the integrity management/PIR approach. A single design factor of 0.72 should be allowed with a different design factor for special areas (identified sites).

AGA:

AGA focused on the impact of changing class locations on a large distribution company with pipeline classified as gas transmission. Applying the current class location change requirements can be expensive – in excess of $1 million per change. The current waiver/special permit process for current class location changes is very burdensome, the renewal process is increasingly more complex, and the outcome is uncertain. AGA suggested the elimination of the

[67] INGAA states that the special permit process is onerous, but submits the special permit conditions as the bifurcated approach categories (page 39) of requirements for existing pipelines when the class location changes to a lower class location, such as Class 1 to 3, Class 1 to 4, or Class 2 to 4 highlighted on pages 39, 40 and 41 of this report. PHMSA implements the special permit requirements found in 49 CFR § 190.341 when reviewing and granting a special permit.

[68] The Class location special permit process was developed from integrity management concepts. PHMSA published the special permit matrix criteria on the Federal Register (69 FR 22115 and 69 FR 38948) on April 23, 2004 and June 29, 2004: Docket No. RSPA-2004-17401 - Pipeline Safety: Development of Class Location Change Waiver (Special Permit). The public meeting and special permit process can be found at: http://primis.phmsa.dot.gov/classloc/meetings.htm. Appendix B-1 through 10 of this report has documents developed to evaluate class location special permits. Since the Class location special permits are mostly reviewed for older pipelines that may have manufacturing, construction, or on-going maintenance issues, such a seam cracking, pipe body cracking, poor external coating, insufficient soil cover, lack of material records, dents, or anomaly repairs not made to design safety factors that may impair the pipeline and diminish public safety, PHMSA believes that the present overall special permit conditions and process methods are consistent with public safety and should not be changed. PHMSA does make modifications to the special permit conditions when it is in the interest of public safety to do so. There have been over 15 special permits for class location changes issued since June 29, 2004 by PHMSA to Gas Transmission Pipeline Operators.

special permit process for class location changes and incorporate specific requirements for special permits into 49 CFR Part 192. AGA recommended two approach methods, one based on IM and the other using the current class location approach. AGA considered that changing the way class locations are determined is very complex, as it is deeply embedded in the current regulations.

APGA:

APGA suggested that IM requirements should not be extended outside of HCAs, as this does not make sense for municipal utilities. A major change to how class locations are determined would require a major rewrite of the Code. There are only 56 publically-owned transmission lines out of 1000 gas transmission pipeline operators. APGA would like to see a revision to the definition of transmission lines to eliminate low pressure, small diameter pipelines operating at low stress levels. Many publically owned "transmission" pipelines are sole suppliers to metropolitan areas. This makes complying with potential changes to IM regulations outside of HCAs problematic. If the regulations are changed to allow use of the PIR approach, operators should have the option to continue using the current class location method.

Gas Processors Association:

The Gas Processors Association (GPA) indicated that 41% of gathering pipelines operating at 20% SMYS in Class 1 locations or above are 4 inches or less in diameter. Class locations are deeply embedded into the Code and the use of class locations is familiar to operators. The current method should be retained. If the PIR approach is adopted, operators should be allowed a choice.

Pipeline Safety Trust:

The Pipeline Safety Trust pointed out how deeply class location is embedded in the Code, and that IM requirements and class locations overlap in densely populated areas to provide an overlapping safety regime. In time, the older class location method can be replaced with a more science-informed IM regulation. Incidents and data suggest there is room for improvement in the IM regulations. Data shows higher incident rates in HCAs than in non-HCAs. Data trends show leaks are increasing while significant incidents have stayed constant over a ten-year period. Newer pipe (installed in 2010 and beyond) has a higher incident rate (by a factor of 2) than pipe installed in the next highest decade. The Pipeline Safety Trust supports expanding IM program requirements outside of HCAs using the MCA concept, but keeping the current class location method for now.

Accufacts:

Accufacts is another public interest group. The presenter acknowledged that class locations are embedded in the Code. He noted that less than 7% of gas transmission pipeline is in HCAs, and that HCA mileage is decreasing, when it should be increasing based on population growth alone. IM is highly dependent on an operator's ability to recognize threats, assess threats, evaluate risks, and identify HCAs. He suggested that it is hard to have confidence in IM programs. He also suggested that the public does not want to hear about lessons learned following a tragic incident. He noted that the San Bruno, CA incident exposed weaknesses in the operator's IM program. He also suggested that the use of a PIR is clearly not appropriate for large diameter pipelines as demonstrated by the San Bruno, CA incident. IM 1.0 has serious flaws and needs improvement. Shifting the class location approach to IM would seriously decrease protection of public safety. Fixing IM regulations should be PHMSA's first priority. Accufacts wants effective, clear regulations not complex, unenforceable regulations. The current class location method should be retained for now and opened for public discussion after IMP 2.0 is implemented.

Following the conclusion of the April 16, 2014, Class Location Workshop, Northern Natural Gas (NNG) and INGAA provided additional comments on the docket.[69] Summaries of the comments are provided below.

NNG:

NNG[70] suggested the creation of an alternative method for identifying class location, in that operators be allowed to select from the existing methodology or an alternative methodology. The alternative would rely on the concept of a "sliding class location circle" that would have a radius of 100 yards or a distance determined by the PIR, whichever is greater. Because the length of the class location circle would be less than one mile under the existing class location methodology, NNG proposed alternative criteria for building counts for each class location. NNG proposed that operators be required to state in their operating procedures which method they use by pipeline, and that a significant change by an operator would require change management control and notification to PHMSA.

NNG also suggested that when a change in class location occurs operators should be allowed to consider the PIR and choose from among two methods for mitigation. This would include; (1) keep the existing method and perform a design factor change, or (2) allow the segment to be incorporated into the IMP as a covered segment. The second alternative would consider the segment as if it were within a HCA (even if were not, in fact), and could either include integrity assessments, depending on specific criteria.

INGAA:

INGAA[71] supported a bifurcated approach that would retain the current class location system for existing pipelines and would permit the use of the PIR for new or entirely replaced pipelines. INGAA stated that this approach would retain current class location definitions and class location pipe upgrade criteria to define the conditions for class location upgrades that have been used for over 40 years. However, INGAA also suggested an alternative to class location upgrades for existing pipelines that would not require the pipeline to be replaced or retested.

[69] Docket ID PHMSA-2013-0161.

[70] Comments by Northern Natural Gas Company concerning "Notice of Inquiry Pipeline Safety: Class Location Requirements" (Docket No. PHMSA-2013-0161) and the April 16, 2014, Class Location Methodology Public Workshop in Washington, D.C., dated May 27, 2014.

[71] Comments of the Interstate Natural Gas Association of America on PHMSA's Public Workshop on Class Location Methodology, Docket PHMSA-2013-0161, dated June 10, 2014.

INGAA also introduced an approach using the PIR to define class locations for new or entirely replaced pipelines. Specifically, INGAA advocated the following high-level concepts:

- INGAA recommended that PHMSA consider a different approach to the current regulations that may require a pipe replacement when a population density increase occurs. This new approach would utilize integrity management principles.
- INGAA recommended a reassessment of the class location design criteria for new pipelines given technological advances in design, materials, engineering and construction (alternative class location approach).

INGAA opined that these concepts address the concerns discussed at the workshop and provide a path forward.

INGAA also presented that:

- Population density increases should not require a pipe replacement, if the pipe can meet certain requirements.
    - An operator 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. Under current pipeline safety regulations, an operator may have to replace pipe if a population increase triggers a change in class location. These replacements often require operators to remove pipe that is in good condition. Replacing a line in good condition does not necessarily make the public safer and is not a good use of resources. The original rulemaking to address class location upgrades based on population increases was developed in 1970 when much of the technology and processes that are common today were not utilized or envisioned. INGAA believes that if a pipeline segment meets certain criteria, it should not arbitrarily be replaced. Therefore, a revision to the existing class location change-out requirements should be considered.
- Advancements in IM technology and processes have superseded the need for mandatory pipe replacement.
    - In the past, it was logical to replace a pipeline when population growth resulted in a class location change because of the widespread belief that a thicker wall pipe would take longer to corrode and additional force would have to be applied (such as from an excavator) for the pipe to fail. This kind of replacement made sense then, when the industry did not have the technology that is available today. Given current technology, pipe quality improvements, and ongoing regulatory processes, pipeline operators can mitigate most threats without pipe replacement.

INGAA's proposal for class location changes for existing pipelines, including pre- and post-1970 pipelines, is summarized as follows:

- No longer require replacement if a pipe segment meets certain requirements. These requirements could provide the safety assurance that PHMSA noted in its development of the IM rule. Specifically, INGAA suggests that PHMSA consider the categories of requirements, listed below, to address any potential safety concerns. PHMSA should engage stakeholders to develop the specific requirements that support these categories. There are many existing sources such as consensus standards that could help develop these requirements. PHMSA's special permit conditions are largely unworkable as a model for the necessary requirements, evident by the fact that no operators have applied for class location special permits since 2010[72].

INGAA proposed the following categories of requirements:

- Baseline Engineering and Record Assessment
- 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

INGAA's proposal for an alternative class location approach that retains class location for existing pipe but permits PIR for new or replaced pipe is summarized as follows:

- INGAA asked PHMSA to consider accepting an alternative class location approach for new pipelines. In INGAA's proposal, the level of O&M and integrity management activities would be determined by the usage/population density within the PIR (see Figure 3-6, below). When a newly constructed pipeline is located in areas with relatively low usage, there would

[72] Since 2010, PHMSA has publicly stated that it did not want to see future requests for special permits for older pipelines or pipelines operating above 72 % SMYS, since it had learned all it needed from them for IM. The majority of the class location special permit requests PHMSA received from pipeline operators were for pipelines in the possible acceptance or requires substantial justification categories with the pipe material and construction being completed prior to the Code, 49 CFR Part 192. The reader can refer to the Federal Register (69 FR 38948, June 29, 2004) for more details. Additional guidance is provided online at http://primis.phmsa.dot.gov/classloc/index.htm.

be a corresponding set of requirements (e.g., level 1). As usage and density within the PIR increases over time, the requirements would be adjusted accordingly.

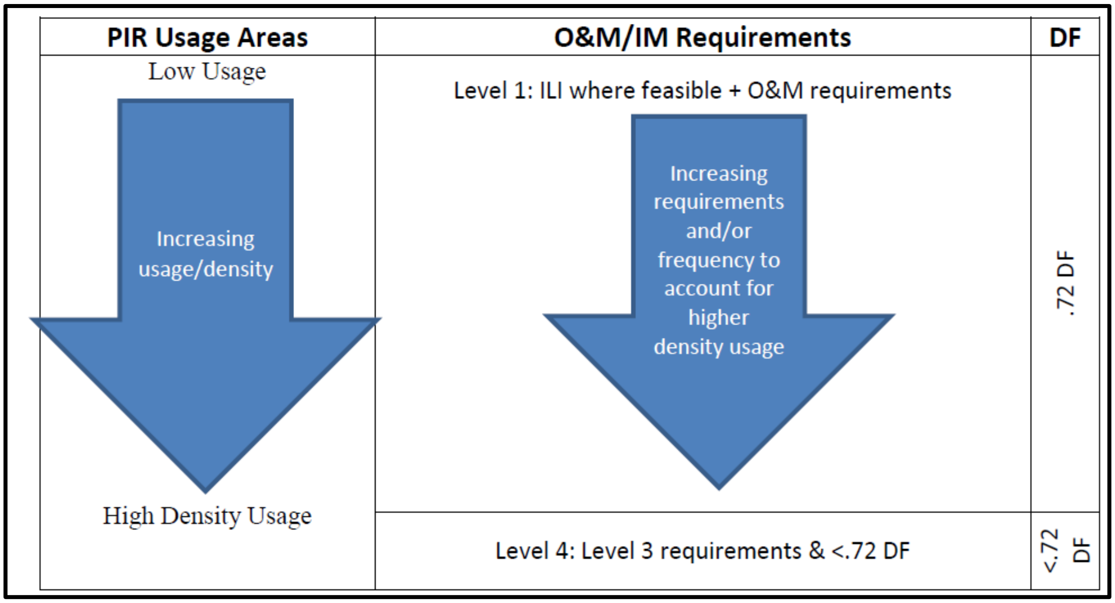

Figure 3-6: INGAA - Figure 1: Alternative Class Location Approach Concept

- INGAA suggested that PHMSA incorporate various design, baseline, and ongoing requirements that would fall into the levels shown in Figure 3-6, above, to accommodate the alternative class location approach. These requirements would follow the same format as those proposed above for class location change-outs.
- INGAA proposed categories of requirements for existing pipelines when the class location changes to a lower class location, such as Class 1 to 3, Class 1 to 4, or Class 2 to 4:
  - Design and Construction Conditions:
    - New technology pipe & coating
    - Construction Quality Assurance/Quality Control Processes
    - Valve location, spacing, and automation
    - Odorization
  - Baseline Assessments:
    - In-line Inspection Assessments
    - Close interval survey
    - Cathodic Protection
    - Construction defects
    - Interference Currents Control
  - Ongoing Assessments:

- Integrity Management Program
- In-line Inspection Assessments
- Stress Corrosion Cracking Assessments
- Metal Loss Anomaly Management
- Dent Anomaly Management
- Cathodic Protection
- Root Cause Analysis for Failure or Leak
- Line Markers
- Patrols
- Leakage Surveys
- Damage Prevention Best Practices
- Recordkeeping & Documentation

Summary:

Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class used for establishing MAOP and O&M surveys for existing pipelines. Industry strongly advocates for changes to the regulations to address pipe replacement where the class location changes. With respect class location requirements, some industry groups and operators supported some type of bifurcated approach for new or replaced transmission pipelines.

PHMSA developed the class location special permit process from IM concepts. Since the Class location special permits are mostly reviewed for older pipelines that may have manufacturing, construction, or on-going maintenance issues, such a seam cracking, pipe body cracking, poor external coating, insufficient soil cover, lack of material records, dents, or anomaly repairs not made to design safety factors that may impair the pipeline and diminish public safety, PHMSA believes that the present overall special permit conditions and process methods are consistent with public safety and should not be changed. PHMSA does make modifications to the special permit conditions when it is in the interest of public safety to do so. There have been over 15 special permits for class location changes issued since June 29, 2004 by PHMSA to Gas Transmission Pipeline Operators.

PHMSA does not support changing the class location requirements for existing/older pipelines. PHMSA considers a possible use of the bifurcated approach on new pipelines through use of a minimum PIR and a maximum PIR based upon pressure and diameter to determine Class locations 1 through 4 using dwelling counts in each class location. The minimum and maximum PIR would replace the present 660 feet radius on each side of the pipeline centerline for determining class location.

3.6 Class Location Approach versus IMP Approach

Table 3-6 presents a breakdown of gas transmission pipeline mileage in class locations by total class location mileage and HCA mileage. HCA mileage is a relatively small subset of pipeline segments.

Table 3-6

Gas Transmission Mileage by Class Location[73]				
Class Location	**Total Miles**	**%**	**HCA Miles**	**%**
Class 1	237,804	78.5	1,600	8.2
Class 2	30,500	10.1	1,403	7.1
Class 3	33,476	11.1	15,887	80.9
Class 4	952	0.3	744	3.8
Total	**302,732**	**100**	**19,634**	**100**

Class locations and HCAs were designed for very different purposes. While class locations drive design, construction, testing, MAOPs, and O&M requirements, HCAs were designed to simply determine if a segment of pipeline needed to be included in an integrity management program. HCAs may force an operator to make repairs and assessments, but are not used to establish MAOP or perform operational inspections, repairs, and surveys. Class locations do not address the potential reduction in safety margin over the course of time due to corrosion or other types of pipe degradation. IM requirements and HCA calculations provide a continuing minimum safety margin for more densely populated areas because operators are required to conduct periodic inspections of the pipe and repair timelines are specified for the anomalies identified within an HCA.

Class location requirements provide an additional safety margin for more densely populated areas relative to less densely populated areas. For instance, a Class 4 location (multi-story buildings) has a safety factor of 0.4, while a Class 2 location 11 to 45 dwellings) has a safety factor of 0.6. Class locations are determined based on the density of dwellings using a 660foot wide sliding mile on either side of a pipeline's centerline. For larger diameter, higher pressure pipelines with PIRs greater than 660 feet, the current class location methodology may not account for all the buildings within the pipeline's potential impact radius. For small diameter, low pressure pipelines with a PIR less than 660 feet, the class location methodology may account for a larger number of buildings than are within a pipeline's potential impact radius. This is illustrated in Figure 3-7 below, which shows PIR as a function of pipe diameter and MAOP. (The example illustrates a pipeline with a PIR of 660 feet, which corresponds to the existing class location unit width).

As population increases in the vicinity of the pipeline, the change in class location may require a pressure test (at higher pressures than previously tested) or new pipe with updated safety features to revalidate MAOP.

[73] Gas Transmission Class Location Mileage (Source: 2013 Annual Report Data as of July 27, 2014).

If the PIR approach was used instead of class location[74], a pipeline with a pipe diameter greater than 30-inch and 1000 psi MAOP would require class locations requirements to be based upon a width greater than 660-foot wide on either side of a pipeline's centerline as presently required. However, because PIR would use sliding PIR instead of sliding mile, in some instances operators may be able to more precisely apply class location requirements to the impacted outside boundary limits of a failure or a rupture. Table 3-7 below shows gas pipeline mileage based upon diameter. Based upon 2013 annual report data, 80,947 miles of operating pipelines are 30-inch and greater diameter. In the past 20-years many new large diameter pipeline mileage, 30-inch or larger diameter, have been designed and are operated at MAOP's greater than 1000 psi. Examples of pipelines built at larger diameters and operating pressures are the Alliance Pipeline and Rockies Express Pipelines. These pipelines were built in the late 1990's to mid-2000's using 42-inch pipe and operate at MAOPs of 1440 psi or greater. A 42-inch diameter pipeline that operates at a 1440 psi MAOP would have a PIR of 1594 feet. This would require the present class location sliding mile to be increased from 660 feet to either 1594 feet or greater. Pipelines with diameters less than 30-inch and MAOPs less than 100 psi would have PIRs less than 660 feet. An example is a 16-inch diameter, 800 psi MAOP, which would have a PIR of 453 feet. For this example, class location overstates the number of buildings in the pipe's potential impact radius.

[74] If PIR was used instead of the "sliding mile" it would still need to be on the "sliding mile" concept (sliding PIR). The PIR distance on either side of the pipeline centerline would be used for the dwelling count instead of the present 660-foot distance presently used in Part 192.

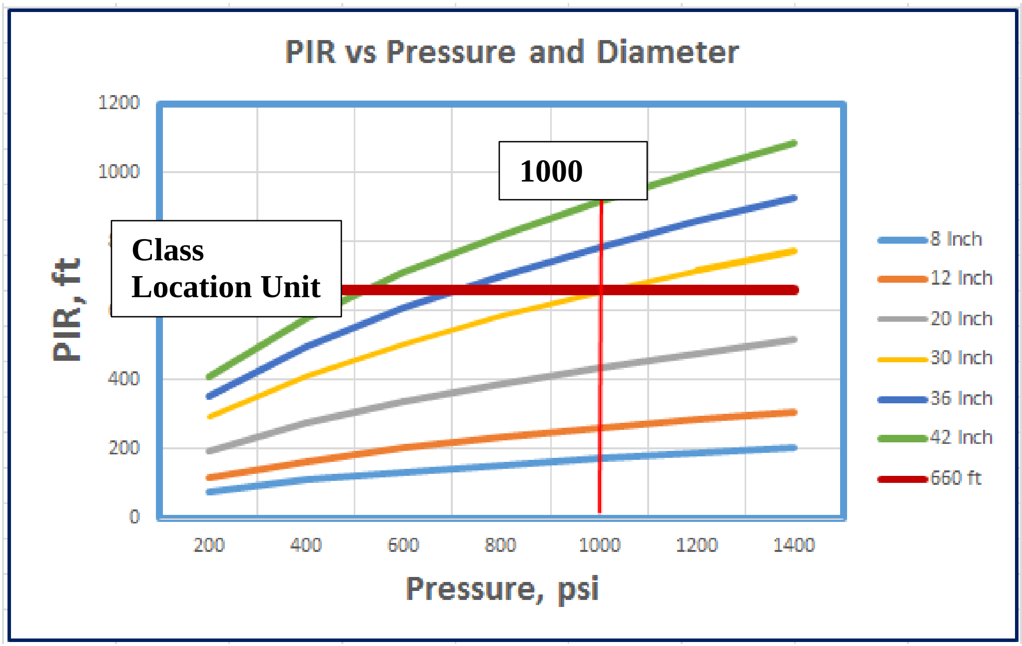

Figure 3-7: PIR[75] vs. MAOP and Diameter (Example for 30-inch diameter, 1000 psi pipeline)

Table 3-7
Gas Transmission, Distribution and Gathering
Mileage by Pipe Diameter[76]

Pipe Diameter (inches)	≤ 12	> 12 to 28	> 28 to 32	> 32	Total Mileage
Gas Transmission (miles)	114,083	107,253	43,312	37,635	302,283
Gas Distribution – Mains (miles)	1,244,078	9,255	--	--	1,253,333

[75] PIR (feet) = 0.69(pressure (psi) x diameter (inches)^2)$^{1/2}$.

[76] Gas Transmission, Distribution, and Gathering Mileage (Source: 2013 Annual Reports as of July 21, 2014). Table 3-6 on page 39 of this report has a gas transmission total mileage that is 449 miles different have Table 3-7 due to reporting differences from pipeline operators on annual reports and the date of information.

Gas Gathering (miles)	13,161	3,737	395	136	17,429
Totals	**1,371,322**	**120,245**	**43,707**	**37,771**	**1,573,045**

3.7. Alternatives to Class Locations

At the April 16, 2014, PHMSA Class Location Workshop, PHMSA presented a number of alternatives to the current method of determining class locations. The alternatives are discussed below. The current method is based on the density of structures within a sliding mile that is 660 feet wide on either side of a pipeline centerline or a well-defined outside area,[77] as defined by § 192.5(b)(3)(ii), within 300 feet on either side of a pipeline centerline.

3.7.1 Single Design Factor

PHMSA solicited comments[78] on the use of a single design factor for all pipelines in locations where there may be large concentrations of people, such as schools, hospitals, nursing homes, multiple-story buildings, stadiums, and shopping malls as an alternative to the current method for determining class locations.

The comments on the use of a single design factor were overwhelmingly negative. Commenters felt that to mitigate class locations by going to a single design factor approach impacts too many 49 CFR Part 192 code sections, would be too complicated to implement, and may even result in a decrease in safety.

An additional safety factor[79] would likely need to be considered if this method were proposed.

3.7.2 Sliding Mile Based upon Potential Impact Radius

The current sliding mile methodology for determining a class location could be replaced by a methodology based on a sliding potential impact radius.

PIRs are a function of pipe diameter and MAOP. Small diameter pipe with a low MAOP would most likely have a PIR less than 660 feet. Large diameter pipe with a high MAOP, typical of large diameter, gas transmission pipelines being constructed today, would most likely have a PIR

[77] An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

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

[79] PHMSA does not believe it is in the interest of public safety to have a single design factor for all class location areas due to the compressibility of natural gas and the likelihood of a high pressure gas transmission pipeline rupture failure being an explosion and fire similar to the San Bruno, CA, Carlsbad, NM, and Edison, NJ pipeline ruptures.

greater than 660 feet. A PIR of 660 feet is equivalent to a 30-inch diameter pipe with an MAOP of 1000 psi or greater.

NNG has proposed an alternative method to the PIR approach, calling it the class location circle approach. A class location circle would be either 300 feet in radius or the PIR whichever is larger. NNG also proposed specific building density criteria to be used with its proposed approach, as follows:

- Class 1: Two or less buildings intended for human occupancy;
- Class 2: Three to eleven buildings intended for human occupancy;
- Class 3: More than eleven buildings intended for human occupancy or an identified site within the class location circle; and
- Class 4: Three or more 4-story buildings within the class location circle.

3.7.2.1 Pros of Using a PIR Approach for Determining Class Location

- PIRs greater than 660 feet could include buildings that are currently excluded from the class location criteria;
- A PIR approach would provide additional safety over the current methodology for PIRs greater than 660 feet;
- The PIR approach could be tied to class location, thus minimizing required Code changes and the impact on operators;
- If tied to IMP requirements, more repairs would be performed on the pipelines because of the required assessments;
- If tied to IMP requirements; the amount of pipe that would have to be replaced due to a class location change would be minimized as the true condition of the pipe would be known through required assessments;
- Could be applied to all pipelines including gas distribution and gas gathering;
- Could be applied to all gas pipelines including steel or plastic;
- O&M functions may be reduced because they are captured by IMP requirements;
- The PIR approach may make determination of class locations easier; and
- The PIR method could be defined in a way to account for certain populated locations (such as schools) that are not captured by the current class location definition.

3.7.2.2 Cons of Using PIR Approach for Determining Class Locations

- The PIR approach may exclude buildings (thus potentially resulting in lower class location grades and less margins of safety at those locations) for PIRs less than 660 feet.[80]
- Any changes to the definition and usage of class locations in 49 CFR Part 192 will require a very through process, since class locations affect all gas pipelines including transmission (interstate and intrastate), gathering, and distribution pipelines.

[80] Buildings could be outside the PIR and inside the 660 feet area of a class location this would change the class location safety factor. Buildings that may be outside the PIR can still be impacted from a rupture.

- The PIR approach does not take into account the pipe wall thickness, grade, seam type, testing history, or design factor that is used to determine the pipeline maximum allowable operating pressure for the class location.
- .
- Multiple sections of the Code currently use class location for defining certain requirements including 12 subparts and 28 sections. The sections are 49 CFR Part 192, Subparts A, B, C, D, E, G, I, J, K, L, M, and O as described below. All would need to be revised to reflect changes:

  49 CFR Part 192 – Subparts that use Class Locations
  - Subpart A – General – *Class Location*
  - Subpart B – Materials – *Pipe Wall Thickness or Grade/Strength*
  - Subpart C - Pipe Design – *Design and Operating Pressures*
  - Subpart D - Design of Pipeline Component – *Design and Operating Pressures*
  - Subpart E - Welding of Steel in Pipelines – *Non-Destructive Tests*
  - Subpart G - General Construction – *Depth of Cover*
  - Subpart I – Corrosion Control – *Corrosion Remaining Strength and Repairs*
  - Subpart J - Test Requirements – *Test Pressure Factor*
  - Subpart K – Uprating – *MAOP, Test Pressure, Class Location, & Repair*
  - Subpart L—Operations – *Class Location and MAOP*
  - Subpart M—Maintenance – *Inspection Intervals*
  - Subpart O—Gas Transmission Pipeline IM – *HCA Determination – Method 1*

  49 CFR Part 192 – List of sections impacted by Class Locations
  - § 192.5 - Class Locations
  - § 192.8 - How are onshore gathering lines and regulated onshore gathering lines determined?
  - § 192.9 - What requirements apply to gathering lines?
  - § 192.65 - Transportation of pipe
  - § 192.105 - Design formula for steel pipe
  - § 192.111 - Design factor (F) for steel pipe
  - § 192.123 - Design of plastic pipe
  - § 192.150 - Passage of internal inspection devices
  - § 192.175 - Pipe-type and bottle-type holders
  - § 192.179 - Transmission line valves
  - § 192.243 - Nondestructive testing - girth welds
  - § 192.327 - Depth of cover
  - § 192.485 - Remaining strength and remedial measures
  - § 192.503 - General requirements
  - § 192.505 - Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS
  - § 192.609 - Change in class location: Required study
  - § 192.611 - Class change: Confirmation/revision of MAOP
  - § 192.613 - Continuing surveillance
  - § 192.619 - MAOP determination

  - § 192.620 - Alternative MAOP
  - § 192.625 - Odorization
  - § 192.705 - Patrolling
  - § 192.706 - Leakage surveys
  - § 192.707 - Line Markers
  - § 192.713 - Permanent field repairs of imperfections/damages
  - § 192.903 - High Consequence Area - Method 1
  - § 192.933 - Integrity assessments of anomalies
  - § 192.935 - What additional P&M M must an operator take?
- A PIR is only applicable for flammable gases (not other toxic gases such as chlorine). Current class location methodology is independent of product being transported;
- Criteria for class locations would need to be redefined;
- Allowing the PIR approach to be used for new pipelines and replaced pipelines may introduce O&M regulatory complexities;
- Allowing the PIR approach to be used for new and replaced pipelines would not alleviate one of industries major concerns with the current methodology, i.e., the replacement of existing pipe when class locations change;
- Criteria would need to be developed to define PIR-based methods for design, construction, testing, operations and maintenance regulatory requirements;
- O&M functions for small diameter and low pressure pipe might be lost;
- State programs rely on class location for state-specific rules;
- The regulation of gas gathering pipelines is determined by the current class location methodology;
- It is unclear how distribution pipeline operators would deal with the change to a PIR-based system;
- Existing methodologies for calculating the remaining strength of pipelines due to defects could be adversely affected. Current programs rely on class location factors for safety margins;
- Work management systems and geographic information system class calculators would need to be revised to reflect a PIR-based system;
- It might be necessary to revisit HCA definitions, which do not necessarily include all the pipe that would need to be included in IM using the PIR-based approach to class location;
- Implementation complexities include:
  - Dealing with legacy (both pipe/material[81] and construction techniques[82]), grandfathered (§ 192.619(c)), low pressure tested, or untested pipelines;

[81] Legacy pipe means steel pipe manufactured using techniques such as: low-frequency electric resistance welded; direct-current electric resistance welded; single submerged arc welded; electric flash welded; wrought iron; pipe made from Bessemer steel; or any pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0 (such as lap-welded pipe) or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specifications.

[82] Legacy construction techniques mean usage of any historic, now-abandoned, construction practice to construct or repair pipe segments, including any of the following techniques: wrinkle bends; miter joints exceeding three

- o Methods for increasing MAOP (uprating) when using a PIR-based approach;
- o Criteria for repairs and remediation outside of current HCAs;
- o Dealing with undocumented material records for pipe and components;
- o All existing interpretations, advisory bulletins, waivers, and special permits would need to be reviewed for applicability and possible change or revocation; and
- o Assimilation of significant change since industry understands current class locations methodology, how it applies, and class location driven requirements.

3.7.3 Expand Class Locations

Gas transmission pipelines are currently classified Class 1, 2, 3, or 4 locations. Class 4 is defined as buildings of 4 or more stories are prevalent. Heavily developed urban areas have many buildings over four stories high. Pipeline Safety Trust and the Jersey City, N.J. Mayor’s office felt additional class locations should be established for buildings over four stories tall. The Jersey City, N.J. Mayor’s office recommended three additional Class Locations, 5 through 7, with a sequentially lower design factor in each new class location.

Industry commenters were almost universally against adding additional class locations. They felt that new class locations with design factors lower than the current 0.4 for Class 4 locations would make it difficult to supply natural gas to the newly classified areas.

3.7.4 Bifurcated Approach

The bifurcated approach would keep the current class location method for existing pipelines but add a new method using the PIR approach for new construction and replacement pipelines. This approach would utilize a PIR approach similar to the approach discussed in Section 3.7.2 for new or replacement pipelines only.

3.7.5 Revise §192.611 to Include Additional IM Oriented Methods for Addressing Class Location Changes

One class location alternative to consider is to retain the current method for determining class locations but to revise the regulations for addressing changes to class locations. Such changes might include alternatives in addition to pipe replacement, re-pressure testing, or de-rating, such as incorporation of integrity management practices to validate the condition of the pipe and monitor the pipe within an integrity management process and not allowing pipe with pre-Code pipe with probable seam or body cracking quality issues to be used in the class location upgrade. Such an approach would essentially codify the fundamental requirements currently contained in Class Location Special Permits, thus providing regulatory certainty.

3.7.6 No Change in Class Location Methodology

Retain the current method for determining class locations and evaluating changes to class locations.

---

degrees; dresser couplings; non-standard fittings or field fabricated fittings (e.g., orange-peeled reducers) with unknown pressure ratings; acetylene welds; bell and spigots; or puddle welds.

4. CONCLUSION

Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 required the Secretary of Transportation to evaluate— (1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and (2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements. PHMSA has evaluated this requirement through the direct solicitation of stakeholder feedback, including industry, operator, regulatory agencies, and the public, as well as through public meetings and workshops.

Based upon input from stakeholders, findings from incident investigations, lessons learned, assessments, IM, and O&M, design, and construction considerations, PHMSA has concluded that there is a sufficient basis to propose expanding selected IM program elements (i.e., assessments and remediation of defects on a continuing interval) be applied to additional areas beyond HCAs. For gas transmission pipelines, the assessment and remediation requirements would be limited to selected areas outside HCAs identified as MCAs. This integrity assessment approach for non-HCA locations are addressed in separate NPRMs for both gas transmission and hazardous liquid pipelines.

For gas transmission pipelines, PHMSA believes the application of integrity management assessment and remediation requirements to MCAs does not warrant elimination of class locations. Class locations affect all gas pipelines, including transmission (interstate and intrastate), gathering, and distribution pipelines, whether they are constructed of steel pipe or plastic pipe. Class location is integral to determining MAOPs, design pressures, pipe wall thickness, pipeline repairs, valve spacing, (HCAs), and operating and maintenance inspections and surveillance intervals. Class locations affect 12 subparts and 28 sections of 49 CFR Part 192 for gas pipelines. The subparts and sections are listed and discussed in Sections 3.1.2.4 and 3.7.2.2. While assessment and remediation of defects on gas transmission pipelines is an important risk mitigation program, it does not adequately compensate for other aspects of class location as it relates to other types of gas pipelines, and as it relates (for all gas pipelines) to the original pipeline design and construction such as the design factor, initial pressure testing, establishment of MAOP, valve spacing, surveillance intervals, and other aspects of pipeline safety, that are based on class location. Thus, PHMSA has determined to retain the existing class location requirements.

5. FUTURE CONSIDERATION OF CLASS LOCATION

PHMSA acknowledges that, although it has tentatively decided to retain the class location requirements, industry raised some legitimate issues with the existing rules for implementing class location. A significant issue relates to class location changes. Currently, § 192.611 allows one class change (one class bump) without the operator replacing pipe when population density near the pipeline increases. However, operators have identified that replacing pipe in locations that change from Class 1 to Class 3 (two class bump) are very costly and submit that pipe replacement is not needed when effective integrity management programs are applied to this pipe. Operators submit that safe operation of steel gas pipelines that were originally constructed in Class 1 locations (and operate at pressures up to 72 percent SMYS) that have changed to Class 3 could be achieved using modern day IM program practices.

However, during the past seven (7) years (2007 through 2014), PHMSA has observed problems with pipe and fitting manufacturing quality including low strength material,[83] construction practices, welding, field coating practices, IM assessments and reassessment practices[84, 85] and documentation practices.[86] These problems, which included many large diameter and high pressure pipeline projects (24-inch and larger diameter and pressures over 1000 pounds per square inch), give PHMSA pause in considering approaches that would allow a two class bump (Class 1 to 3 or Class 2 to 4) without pipe replacement for a high pressure gas transmission pipeline. In April 2009, PHMSA held a Construction Workshop reviewing construction quality issues: http://primis.phmsa.dot.gov/construction/meetings.htm. PHMSA set-up a website[87] to notify operators of pipeline material strength problems found during construction inspections and INGAA developed a white paper for pipeline operators to use in ordering pipe for new construction projects.[88] Some examples of the quality issues found on new large diameter (≥ 24-inches) pipeline projects constructed during 2007 through 2012 were as follows:

- One major large diameter pipeline project had eight pressure test failures, two in-service failures, and cut out over 40 defect mainline pipe bends and girth weld fit-up;
- Another major large diameter project had over 200 low strength pipe joints cut-out and replaced;
- Another major large diameter pipeline project had in-service leaks due to the poor quality of pipe bends and girth weld fit-up; and
- Another major large diameter pipeline project had to de-rate the pipe grade due to low strength steel and rejected over 40 pipe fittings due to low strength.

PHMSA is also in the process of developing and implementing safety management systems (SMS) with a national consensus standards organization, in response to NTSB Recommendation P-12-17.[89] The goal of SMS is to improve management involvement at all levels to improve the

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

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

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

[86] 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.

[87] PHMSA developed a website titled "Low Strength Pipe" to inform pipeline operators about material quality issues, which can be reviewed at: http://primis.phmsa.dot.gov/lowstrength/index.htm.

[88] INGAA issued a white paper dated September 2009 titled- "Identification of Pipe with Low and Variable Mechanical Properties in High Strength, Low Alloy Steels", which can be reviewed at: http://www.ingaa.org/?ID=10511

[89] See Pipeline Accident Report NTSB/PAR-12/01, adopted July 10, 2012, Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan, July 25, 2010.

quality of pipeline material, construction, operations, maintenance, and integrity management. On February 27, 2014, July 2, 2014, and April 22, 2015, PHMSA held three workshops seeking stakeholder input on SMS. Information on the workshops is available online at: http://primis.phmsa.dot.gov/meetings.

PHMSA is committed to continued retrospective review of pipe replacement requirements associated with the class locations in 49 CFR Part 192. PHMSA will continue to study and consider if adjustments are needed to the way class locations are defined and reviewed when the class location changes. PHMSA will continue to listen to stakeholder input and consider:

- Comments and suggested approaches submitted on the docket[90];
- More efficient and practical class location approaches that improve safety and avoid unnecessary pipe replacements where safety can be maintained with other robust measures such as incorporating IM principles.

Any changes to the definition and application of class locations in 49 CFR Part 192 will require a very thorough vetting process. Following publication of the final rule titled “Pipeline Safety: Safety of Gas Transmission Pipelines;” (Docket No. PHMSA-2011-0023, RIN 2137-AE72), PHMSA plans to further evaluate the feasibility and the appropriateness of alternatives to address this issue, continue to reach-out to all stakeholders, consider input from all sources, and consider future rulemaking if a cost-effective and safety focused approach to adjusting specific aspects of class location requirements can be developed, in order to address the issues identified by industry. In doing so, PHMSA will evaluate any alternatives in the context of other issues it is addressing related to new construction QMS and SMS, and will also consider inspection findings, IM assessments, and lessons-learned from past incidents. PHMSA intends to initiate a subcommittee of the Gas Pipeline Advisory Committee to identify possible alternatives to our current Class Location requirements, in particular to determine whether PHMSA policies for granting Special Permits for Class Location waiver requests should be incorporated into the pipeline safety regulations. PHMSA also plans to publish an advance notice of proposed rulemaking in the near future to gain further information on analyzing current requirements that result in pipe replacement and alternatives.

[90] Docket No. PHMSA-2011-0023; All comments regarding the Class Location report received in response to Docket No. PHMSA-2011-0023 will be considered during any review of the existing Class Location requirements. Late filed comments will be considered as practicable after the comment period closes for the Pipeline Safety: Safety of Gas Transmission Pipelines NPRM.

Appendix A - Abbreviations

Abbreviation	**Description**
Act of 2011	Job Creation Act of 2011
AGA	American Gas Association
ANPRM	Advance Notice of Proposed Rulemaking
ANSI	American National Standards Institute
APGA	American Public Gas Association
API	American Petroleum Institute
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
BIHO	Buildings Intended for Human Occupancy
CFR	Code of Federal Regulations
FR	Federal Register
GPA	Gas Processors Association
HL	Hazardous Liquid
ILI	In-Line Inspection
IMP	Integrity Management Program
INGAA	Interstate Natural Gas Association of America
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
NAPSR	National Association of Pipeline Safety Representatives
NEB	National Energy Board of Canada
NNG	Northern Natural Gas
NPRM	Notice of Proposed Rulemaking
NTSB	National Transportation Safety Board
O&M	Operations and Maintenance
OPS	Office of Pipeline Safety

PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	Potential Impact Radius
PSIA of 2002	Pipeline Safety Improvement Act of 2002
PSIG	Pounds Per Square Inch Gauge
QMS	Quality Management Systems
RSPA	Research and Special Programs Administration
SMS	Safety Management Systems
SMYS	Specified Minimum Yield Strength

Appendix B – Class Location Waiver Criteria

Criteria for Considering Class Location Waiver Requests

Purpose

This document establishes guidelines for the consideration of requests for waiver of the requirement at 49 C.F.R. § 192.611 to confirm or revise the maximum allowable operating pressure (MAOP) of a natural gas pipeline after a change in class location has occurred. If granted, a class location waiver would allow a pipeline operator to perform alternative risk control activities based on the principles and requirements of the Integrity Management Program in lieu of pipe replacement or pressure reduction.

The provision of class location waivers, where warranted, is intended to benefit both the public and pipeline operators. First, within the waiver area the pipeline operator will be conducting in-line inspections and other assessment methods, substantially increasing the operator's knowledge of the integrity of pipe structures and potentially accelerating the identification and repair of actionable anomalies that could pose a threat to the public and environment. Second, in addition to performing in-line inspections of the pipe located within the waiver areas, in most cases, operators will perform in-line inspection and repairs of any actionable anomalies identified up to 25 miles upstream and downstream of the waiver area, substantially increasing the protection afforded to populated and environmentally sensitive areas along the right of way. Third, provision of a class location waiver may avoid the delivery interruptions, supply shortages, and additional costs associated with excavating and replacing the pipe in the affected areas.

Background

On December 15, 2003, the Office of Pipeline Safety (OPS) published a Final Rule requiring operators of gas transmission pipelines to develop and implement integrity management programs for their pipelines in high consequence areas (68 FR 69778; Dec. 15, 2003). The cost-benefit analysis in the rule states that:

> Another benefit to be realized from implementing this rule is reduced cost to the pipeline industry for assuring safety in areas along pipelines with relatively more population. The improved knowledge of pipeline integrity that will result from implementing this rule will provide a technical basis for providing relief to operators from current requirements to reduce operating stresses in pipelines when population near them increases. Regulations currently require that pipelines with higher local population density operate at lower pressures. This is intended to provide an extra safety margin in those areas. Operators typically replace pipeline when population increases, because reducing pressure to reduce stresses reduces the ability of the pipeline to carry gas. Areas with population growth typically require more, not less, gas. Replacing pipeline, however, is very costly. Providing safety assurance in another manner, such as by implementing this rule, could allow RSPA/OPS to waive some pipe

replacement. RSPA/OPS estimates that such waivers could result in a reduction in costs to industry of $1 billion over the next 20 years, with no reduction in public safety.

In addition to being factored into the cost-benefit analysis of the Integrity Management Program rule, the technical soundness of issuing class location waivers has been considered in connection with the following regulations, standards, and programs:

- The Risk Management Demonstration Program
- The Integrity Management Program regulations (49 C.F.R. Part 192, Subpart O)
- The development of ASME Standard B31.8S "Managing System Integrity of Gas Pipelines"
- Various requests for waiver regarding compliance activities in class location change areas

Candidates for Waiver Consideration

The vehicle for an operator seeking a class location waiver will be through the normal case-by-case waiver approval process. Under 49 U.S.C. § 60118, OPS may grant a waiver of any regulatory requirement if granting the waiver is "not inconsistent with pipeline safety." Therefore, each operator submitting a waiver request has the burden of demonstrating that the proposed waiver would not be inconsistent with pipeline safety with respect to the particular pipe in the affected area. Each waiver request is also subject to public notice and comment. Operators of intrastate pipelines are required to submit waiver requests at the state level.

Beginning in 2004, requests for class location waivers will be considered for a number of candidate sites. During this initial period, OPS will gather data to assess whether the integrity management programs and other alternative risk control activities these waivers would be conditioned upon are being implemented effectively. The monitoring of compliance with the required activities will be conducted through periodic operator reporting requirements as well as scheduled pipeline inspections. If, after a class location waiver is granted, OPS determines that the waiver is no longer consistent with public safety, OPS may take appropriate regulatory action up to and including retraction of the waiver and requiring immediate compliance with the MAOP restrictions otherwise applicable to the changed class location. Any pipeline or pipeline section for which a class location waiver is granted remains subject to all other requirements of 49 C.F.R. Parts 190, 191, and 192.

Criteria

The age and manufacturing process of the pipe, construction processes used and operating and maintenance history are all significant factors that must be considered in the waiver process. Additionally, certain threshold requirements must be met in order for a pipeline section to be considered a candidate site. Among these requirements are:

- No pipe segments changing to Class 4 locations will be considered
- No bare pipe will be considered
- No pipe containing wrinkle bends will be considered
- No pipe segments operating above 72% SMYS will be considered for a Class 3 waiver
- Records must be produced that show a hydrostatic test to at least 1.25 x MAOP
- In-line inspection must have been performed with no significant anomalies identified that indicate systemic problems
- Up to 25 miles of pipe either side of the waiver location must be included in the pipeline company's Integrity Management Program and periodically inspected with an in-line inspection technique

While each waiver request is considered in its entirety, requests involving pipelines with operating conditions reflecting higher risk will merit more rigorous scrutiny and require increasing levels of justification. The following table outlines in more detail the specific parameters of pipe design and operating conditions that OPS considers in reviewing class location waiver requests. It contains three categories specifying: (1) the parameters within which a waiver request is probably consistent with pipeline safety; (2) the parameters within which a request is possibly consistent with pipeline safety; and (3) those within which a request requires substantial justification to demonstrate it is consistent with pipeline safety. These criteria reflect OPS' current thinking and are subject to change as more experience with the issuance of class location waivers is gained.

CRITERIA	PROBABLE ACCEPTANCE	POSSIBLE ACCEPTANCE	REQUIRES SUBSTANTIAL JUSTIFICATION
CLASS LOCATION			
Class Location Change	1 to 2 or 2 to 3	1 to 3	
PIPE DESIGN AND CONSTRUCTION			
Pipe Manufacture	Pipe Manufactured and installed in 1980[1] or later.	Pipe Manufactured and installed prior to 1980.	LF-ERW, DC-ERW, EFW, furnace lap welded pipe, pipe manufactured prior to 1954, pipe of unknown manufacturing process, or pipe known to contain manufacturing defects that could lead to failure (based on manufacturer and year of manufacture).
Pipe Material	Welded steel pipe with toughness meeting the current requirements of ASME B31.8 or pipe of known toughness.[2]	Pipe of low or unknown toughness where the operator has addressed this risk in their integrity management plan.	Pipe other than steel, pipe installed with mechanical joints, or steel pipe of unknown toughness.
Design Stress	Less than or equal to 72% of SMYS.	Up to 80% SMYS for grandfathered systems for Class 2.	
Pipe Girth Welds	Records exist[3] that demonstrate that the girth welds were volumetrically inspected during construction.	At least 1% of girth welds in the waiver location have been excavated and volumetrically inspected following construction.[4]	No radiographic inspection either during of after construction or welds made using oxy-acetylene welding process.
Pipe Coating	FBE, Multi-layer Epoxy	Polyethylene Tape, Coal Tar	Other coating materials.

[1] 1980 was selected as a year after which there is a high degree of confidence that line pipe manufactured in accordance with the requirements of API-5L is free of manufacturing defects that could fail in service. Pipe manufactured prior to 1980 may also be acceptable. OPS will consider revising this date to an earlier date if supported by the vintage pipe study currently being completed by industry.
[2] Pipe purchased to a technical specification that specified a minimum toughness requirement is considered pipe of known toughness.
[3] Records could include purchasing or other records, actual NDE reports or radiographs are not required.
[4] This post construction girth weld volumetric inspection is not required to be evaluated to new construction acceptance criteria. They should be evaluated for evidence of any flaws that would increase the likelihood of a failure as well as any gross construction defects that limit the load carrying ability of the girth weld.

CRITERIA	PROBABLE ACCEPTANCE	POSSIBLE ACCEPTANCE	REQUIRES SUBSTANTIAL JUSTIFICATION
PRESSURE TESTING			
Test Pressure	Tested to at least 90% SMYS and 125% MAOP.	Tested to 125% MAOP.	
Test Failures	No history of pressure test failures.	Some pressure test failures where it can be documented that they are not indicative of a systemic problem in the pipeline system.	Pressure test failures that are indicative of a systemic problem in the pipeline system.
ENVIRONMENTAL CONSIDERATIONS			
Depth of Cover	Cover meeting the requirements of § 192.327 (a).	Additional protection[5] provided when cover does not meets the requirements of §192.327 (a).	Cover not meeting the requirements of §192.327 (a) without additional protection in areas of earth movement such as industrial and quarry activities or plowing on the ROW.
Local Geology	Located in stable soil.	Actions have been implemented to address known geologic instability issues in waiver location.	Known geologic instability issues in waiver location (e.g. flood, subsidence, landslide, fault line) that have not been mitigated.
OPERATIONAL CONSIDERATIONS			
Leaks and Failures	No history of leaks, failures or systemic problems on similar system pipe that is found in the waiver area.[6]	No reportable history of leaks, failures or systemic problems on similar system pipe that is found in the waiver area in the past 20 years.	Reportable leaks or failures from manufacturing defects that are indicative of a systemic integrity issue in the waiver area.
Service	Dry gas service only with adequate protection to prevent wet gas infiltration.[7] No measurable H_2S.	Wet gas service where actions have been taken to prevent internal corrosion (e.g. internal coating). May include trace quantities of H_2S.	Wet gas service. Gas containing measurable H_2S.

[5] Additional protection may include additional damage prevention measures described under damage prevention in this table.
[6] For this protocol, the inspection area containing the waiver location is defined as an area within 25 miles, a compressor station, or permanent inspection tool launcher or receiver site either side of the waiver location which ever is less.
[7] Dry gas service is defined as less than 7 lbs. of water per MMCF.

CRITERIA	PROBABLE ACCEPTANCE	POSSIBLE ACCEPTANCE	REQUIRES SUBSTANTIAL JUSTIFICATION
Pressure Fluctuations	Light to moderate pressure spectrum.		Aggressive to Very Aggressive pressure spectrum or evidence of past fatigue failures[8].
Cathodic Protection	Requirements of 192 Subpart I have been met for entire life of the pipeline with no evidence of coating damage due to excessive current.	Meets requirements of 192 Subpart I and there is no evidence of external corrosion or only isolated corrosion damage that has been appropriately mitigated.	Evidence of systemic corrosion damage in the inspection area[9].
Safety Related Condition Reports	No SRCR's related to line pipe integrity in the inspection area containing waiver location.	No SRCR's related to line pipe integrity in at waiver location.	SRCR's related to line pipe integrity in at waiver location.
INTEGRITY MANAGEMENT PROGRAM			
Program	Entire waiver location treated as an HCA with additional measures applied in inspection area containing waiver location.	Entire waiver location treated as an HCA.	
ILI Time Frame	Performed within two years of waiver application. If ILI is performed after waiver application, waiver is contingent on completion of the inspection and repairs.	Performed within five years of waiver application. If ILI is performed after waiver application, waiver is contingent on completion of the inspection and repairs.	No ILI.
ILI Type	High Resolution Metal Loss and Slope Deformation Tools.	Low Resolution Metal Loss and Geometry Tools.	Low Resolution MFL on seamless pipe.
Direct Assessment (ECDA and SCCDA[10])	Performed in accordance with Subpart O in the waiver area with no significant anomalies.[11]		Significant anomalies or evidence of injurious SCC.

[8] An aggressive to very aggressive pressure spectrum may be typical of that encountered in bi-directional systems or systems associated with gas storage where large frequent pressure cycles occur.
[9] For this protocol, the inspection area containing the waiver location is defined as an area within 25 miles, a compressor station, or permanent inspection tool launcher or receiver site either side of the waiver location which ever is less.
[10] The SCCDA shall include either Wet Fluorescent or High Contrast (black on white) magnetic particle inspection.

CRITERIA	PROBABLE ACCEPTANCE	POSSIBLE ACCEPTANCE	REQUIRES SUBSTANTIAL JUSTIFICATION
Coating Assessment	Coating in good condition with no evidence of disbondment.		Coating in poor condition, significant holidays, or gross disbondment.
Damage Prevention	Damage prevention program based on best practices endorsed by the Common Ground Alliance.		Areas of industrial activity or deep plowing on the ROW without additional damage prevention measures in place
INSPECTION AND ENFORCEMENT HISTORY			
Inspection Findings	No enforcement actions in the OPS Region under consideration in the last five years.	No outstanding enforcement actions in the inspection area containing the waiver location.	Outstanding compliance actions or history of enforcement actions

[11] Since ILI is required in addition to direct assessment, only a single dig site will be required at the waiver location unless the results of the direct assessment indicate that additional investigation is warranted.

Notification Requirements

Under 49 C.F.R. § 192.611(d) class location change sites have a 24-month remediation time limit that begins with the identification of the site. Accordingly, operators who have candidate sites should submit written notice to OPS of their intent to request a class location waiver as early in the 24-month period as possible. With respect to intrastate pipelines, since state agency approval is required, the operator should submit the notice to both the applicable state agency and OPS. In the notification, the operator must include the following information:

- A list of the proposed waiver sites including their beginning and ending mileposts and a map of the class change location(s), adjacent housing and other structures (within the 1320-foot corridor, or C-FER Circle if potential impact radius is greater than 660 feet (must have actual data, do not prorate)), identification of current and previous class location designation, and the reason for the class change. The operator shall indicate when this condition changed creating the new class location area and will provide verification of those date changes.
- Attributes associated with the inspection area containing the proposed waiver location(s) including:
    - Pipe Vintage
        - Date of installation
        - Pipe manufacturer
    - Diameter, wall thickness, grade and seam type
    - Coating type
    - Depth of Cover
    - Local geology and risks associated with the terrain
    - Maximum Allowable Operating Pressure (MAOP) (revised MAOP, if applicable); historical maximum and minimum operating pressure
    - Hydrostatic test records
    - Girth weld radiography records
    - In-line inspection records (date launched, tool type, vendor or operator evaluated log, dig records, was the tool tolerance accurately reflected in digs)
    - Cathodic Protection records
- Identify the inspection area containing the proposed waiver location(s).
- Limits of HCAs within the inspection area containing the proposed waiver location(s), if applicable.
- Direct Assessment results for the proposed waiver area (ECDA, SCCDA, and coating)
- Any incidents associated with the inspection area containing the proposed waiver location(s) (both reportable and non reportable)
- History of leaks on the pipeline in the inspection area containing the proposed waiver location(s) (both reportable and non reportable)
- List of all repairs on the pipeline within the inspection area containing the proposed waiver location(s).

- On-going damage prevention initiatives on the pipeline within the inspection area containing the proposed waiver location(s) and a discussion of its effectiveness.
- A list of all Safety Related Condition Reports related to line pipe integrity submitted on the inspection area containing the proposed waiver location(s).
- A summary of the integrity threats to which the pipe within the site is susceptible based on Part 192 criteria.
- An in-line inspection schedule and a hydrostatic testing schedule (if a valid in-line inspection and hydrostatic test have not already been conducted). These inspections/tests must be scheduled such that they will be completed, and any actionable anomalies remediated in accordance with Part 192, Subpart O, prior to the end of the 24-month compliance window. The operator shall provide 30 days prior notice of any ILI or direct assessments to be performed within the inspection area containing the waiver location(s). Note: Final approval of the waiver will be based on the results of the hydrostatic test and ILI results and remedial activities.
- The operator must determine and provide certification that the inspections/activities associated with this site will not impact or defer any of the operator's assessments for HCAs under Part 192, Subpart O, particularly those associated with the most significant 50%.
- A summary list of any additional proposed alternative risk control activities for each candidate site, including any sites not located in a HCA (i.e., inspections and assessments, electrical surveys, increased patrolling, leak surveys, public education, etc. above and beyond the current requirements of Part 192). Include the mileposts within which each activity would be conducted (additional mileage upstream and downstream of the waiver area is expected) and the proposed time interval for performing the activities on an ongoing basis. Note that OPS may require that the scope or the interval of any proposed alternative risk control activity be modified or require additional activities before granting a waiver.
- Describe the safety benefit both to the specific waiver request site, and areas outside the waiver location. This should specifically include the number of residences and identified sites at the proposed waiver location(s) and within the inspection area containing the waiver location(s).

Reporting Requirements

Within three months following approval of a class location waiver and annually thereafter, operators will be required to periodically report the following:

- Define the economic benefit to the company. This should address both the cost avoided from not replacing the pipe as well as the added costs of the inspection program (required for the initial report only).
- The results of any ILI or direct assessments performed within the inspection area containing the waiver location(s) during the previous year.
- Any new integrity threats identified within the inspection area containing the waiver location(s) during the previous year.
- Any encroachment in the inspection area including the waiver location(s) including the number of new residences or gathering areas.

- Any incidents associated with the inspection area containing the waiver location(s) that occurred during the previous year. (both reportable and non reportable)
- Any leaks on the pipeline in the inspection area containing the waiver location(s) that occurred during the previous year. (both reportable and non reportable)
- List of all repairs on the pipeline the inspection area containing the waiver location(s) made during the previous year.
- On-going damage prevention initiatives on the pipeline in the inspection area containing the waiver location(s) and a discussion on its success.
- Any mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which the waiver applies.

Supplemental Reporting

To the extent possible, the pipeline company should provide the following information with the first annual report:

- Describe the benefit to the public in terms of energy availability. Availability should address the benefit of avoided disruptions required for pipe replacement and the benefit of maintaining system capacity.