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**DEPARTMENT OF TRANSPORTATION**

**Pipeline and Hazardous Materials Safety Administration**

**49 CFR Parts 191, 192, and 195**

**[Docket No. PHMSA-2010-0026; Amdt. Nos. 191-23; 192-120; 195-100]**

**RIN 2137–AE59**

**Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations**

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

**ACTION:** Final Rule.

**SUMMARY:** PHMSA is amending the pipeline safety regulations to make miscellaneous changes that update and clarify certain regulatory requirements. These amendments address several subject matter areas including the performance of post-construction inspections, leak surveys of Type B onshore gas gathering lines, qualifying plastic pipe joiners, regulation of ethanol, transportation of pipe, filing of offshore pipeline condition reports, and calculation of pressure reductions for hazardous liquid pipeline anomalies.

The changes are addressed on an individual basis and, where appropriate, made applicable to the safety standards for both gas and hazardous liquid pipelines. Editorial changes are also included.

**DATES:** The effective date of these amendments is October 1, 2015. Immediate compliance with these amendments is authorized. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of March 6, 2015.

**FOR FURTHER INFORMATION CONTACT:** Kay McIver, Transportation Specialist, by telephone at 202-366-0113, or by electronic mail at [kay.mciver@dot.gov](mailto:kay.mciver@dot.gov).

**SUPPLEMENTARY INFORMATION:**

I. Background

A. Notice of Proposed Rulemaking

On November 29, 2011, PHMSA published a Notice of Proposed Rulemaking (NPRM) under the docket, PHMSA-2010-0026, (76 FR 73570), notifying the public of the proposed changes to 49 CFR Parts 191, 192, and 195. We allowed an initial 90-day comment period, but based on requests from several pipeline trade associations, the comment period was extended from February 3, 2012, to March 6, 2012, (77 FR 5472). Most of the amendments proposed in the NPRM were intended to provide relief to industry by eliminating, revising, clarifying, or relaxing regulatory requirements.

B. Advisory Committee Meetings

On July 11 and 12, 2012, the Technical Pipeline Safety Standards Committee (commonly referred to as the Gas Pipeline Advisory Committee (GPAC)) and the Technical Hazardous Liquid Pipeline Safety Standards Committee (commonly referred to as the Liquid Pipeline Advisory Committee (LPAC)), met jointly at the Marriott Hotel at Metro Center in Washington, DC. The Pipeline Advisory Committees (PACs) are statutorily mandated advisory committees that advise PHMSA on proposed safety standards, risk assessments and safety policies for natural gas pipelines and hazardous liquid pipelines. The PACs were established under the Federal Advisory Committee Act (Pub. L. 92-463, 5 U.S.C. App. 1-16) and the Federal Pipeline Safety Statutes (49 U.S.C Chap. 601). Each committee consists of 15 members, with membership divided among the Federal and state agencies, the regulated industry and the public. The PACs advise PHMSA on the technical feasibility, practicability and cost-effectiveness of each proposed pipeline safety standard. During the meeting, the PACs considered the NPRM and discussed the various comments and edits proposed by the pipeline industry and the public regarding changes to the regulations.

The PACs recommended PHMSA adopt the following proposals with minor or no changes to the regulatory text:

- Leak Surveys for Type B Gathering Lines;
- Qualifying Plastic Pipe Joiners;
- Regulating the Transportation of Ethanol by Pipeline;
- Transportation of Pipe;
- Threading Copper Pipe;

- Offshore Pipeline Condition Reports;
- Alternative Maximum Allowable Operating Pressure (MAOP) Notifications;
- National Pipeline Mapping System;
- Welders vs. Welding Operators;
- Components Fabricated by Welding; and
- Editorial Amendments.

The PACs recommended PHMSA adopt the following proposals with changes to the regulatory text:

- Responsibility to Conduct Construction Inspections;
- Mill Hydrostatic Tests for Pipe to Operate at Alternative MAOP;
- Calculating Pressure Reductions for Hazardous Liquid Pipeline Integrity Anomalies; and
- Testing Components other than Pipe Installed in Low-Pressure Gas Pipelines.

The PACs recommended that PHMSA not adopt the proposed changes to:

- Limitation of Indirect Costs in State Grants; and
- Odorization of gas.

This Final Rule adopts the recommendations of the PACs. Additional discussion of the amendments and associated comments of the PACs are provided below:

## II. Proposals Addressed in this Final Rule

1. Responsibility to Conduct Construction Inspections.
2. Leak Surveys for Type B Gathering Lines.
3. Qualifying Plastic Pipe Joiners.
4. Mill Hydrostatic Tests for Pipe to Operate at Alternative MAOP.
5. Regulating the Transportation of Ethanol by Pipeline.
6. Limitation of Indirect Costs in State Grants.
7. Transportation of Pipe.
8. Threading Copper Pipe.
9. Offshore Pipeline Condition Reports.
10. Calculating Pressure Reductions for Hazardous Liquid Pipeline Integrity Anomalies.
11. Testing Components other than Pipe Installed in Low-Pressure Gas Pipelines.
12. Alternative MAOP Notifications.
13. National Pipeline Mapping System.
14. Welders vs. Welding Operators.
15. Components Fabricated by Welding.
16. Odorization of Gas.
17. Editorial Amendments.

### III. Commenters to the Rule.

PHMSA received a total of 42 comments on the NPRM, to include:

- 15 from pipeline trade associations.

- 17 from pipeline operators.
- 3 from pipeline manufacturers.
- 3 from states and municipalities.
- 1 from a Federal source (the National Transportation Safety Board (NTSB)).
- 3 from private organizations/citizens.

#### IV. Discussion of Public Comments on Individual Issues

In this section, PHMSA discusses the changes proposed in the NPRM and the comments received in response to the NPRM. Based on an assessment of the proposed changes and the comments received, PHMSA identifies the proposals that are adopted in this Final Rule.

##### **(1) Responsibility to Conduct Construction Inspections § § 192.305 and 195.204.**

**Proposal:** PHMSA proposed to revise § 192.305 to specify that a transmission pipeline or main cannot be inspected by someone who participated in its construction. This proposal was based, in part, on a petition (Docket No. PHMSA-2010-0026) from the National Association of Pipeline Safety Representatives (NAPSR),<sup>1</sup> that suggested that contractors who install a transmission line or main should be prohibited from inspecting their own work for compliance purposes. This petition was also based on the experiences of NAPSR members concerned with the poor quality of construction by unsupervised contractors.

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<sup>1</sup> NAPSR is a non-profit organization of state pipeline safety personnel who serve to promote pipeline safety in the United States and its territories. Its membership includes the staff manager responsible for regulating pipeline safety from each state that is certified to do so or conducts inspections under an agreement with DOT in lieu of certification.

PHMSA agreed with NAPSRS but recognized that the same concerns should apply to non-contractor pipeline personnel and to hazardous liquid lines. Accordingly, PHMSA proposed to revise §§ 192.305 and 195.204 to specify that a transmission pipeline main, or pipeline system, cannot be inspected by someone who participated in its construction.

**Comments:** This topic was the most controversial of all the proposed items. Comments included the following concerns and recommendations:

- The proposed rule will result in significant cost impact to operators;
- The proposal is overly burdensome economically and has the potential to compromise site safety due to additional personnel, congestion, inattention, carelessness and unnecessary overhead expenses;
- The proposed amendment is clearly a significant regulatory action and is inappropriately included in a non-significant rulemaking and should be considered in a separate rulemaking;
- The proposed language does not differentiate between an operator's employee and a contractor's employee;
- PHMSA should clarify the meaning of "person participating in the construction" of a pipeline;
- Inspection and new construction should be an Operator Qualification (OQ) task;
- Prohibiting any "person" involved in the construction of a pipeline could be interpreted to prohibit any other municipal employee from performing inspection; and

- PHMSA should re-define “a person who participated” in the construction of the pipeline.

NAPSR commented that their resolution was intended to preclude operators from allowing contractor personnel to self-inspect their own work and was based on its members’ experience with poor quality of construction by unsupervised contractors.

Members of the Association of Oil Pipelines (AOPL) said they do not agree with the statement that “the proposed rule does not impose any compliance, recordkeeping or other reporting requirement.” AOPL said the proposed change to § 192.305 will result in significant cost to the operators. In addition, AOPL asserted that the proposal is overly burdensome economically and has the potential to compromise site safety due to additional personnel, congestion, inattention, carelessness and unnecessary overhead expense.

The American Gas Association (AGA) noted that PHMSA has failed to provide an analysis to support the significant expansion of the construction inspection revision to all entities and personnel encompassed in the § 192.3 definition of “person.” Another commenter noted that PHMSA did not provide a basis for its conclusion on construction inspection and PHMSA’s proposed rule does not address the same concerns as NAPSR. The Interstate Natural Gas Association of America (INGAA) noted that instead of adopting the proposed amendment, which increases regulatory confusion and adds to the issues already surrounding construction, PHMSA should convene a public hearing or



workshop to develop the fundamental regulatory changes needed to align PHMSA's policy objectives with common pipeline configurations.

**Response:** Consistent with the petition from NAPSR, PHMSA proposed to revise §§ 192.305 and 195.204 to prohibit individuals involved in the construction of a transmission line, main or pipeline system from inspecting his or her own work. These inspections are important because transmission pipelines and mains are generally buried after construction. Subsequent examinations often involve a difficult excavation process. PHMSA believes that allowing individuals to inspect their own work defeats, in part, the measure of safety garnered from such inspections. PHMSA was not intending to require third party inspections or attempting to prohibit any person from a company to inspect the work of another person from the same company.

The PACs did not agree with the proposed language. There was considerable discussion on the use of alternative language proposed by INGAA and the original language from the NAPSR petition.

Following the discussion, the PACs agreed on the revised language for gas and hazardous liquid pipelines. After reviewing the PACs' recommendations and evaluating public comments, PHMSA has adopted language that more clearly identifies the types of individuals who should be excluded from the required inspections, (i.e., the individual who performed the construction task that requires inspection).

In regard to the comments that dealt with costs and the significance of the rule, PHMSA believes that the commenters overstated the impact of the proposal.

**(2) Leak Surveys for Type B Gathering Lines § 192.9.**

**Proposal:** In the NPRM, PHMSA proposed that operators of Type B gathering lines must perform leak surveys in accordance with § 192.706 and fix any leaks discovered.

Operators of Type B gathering lines currently must ensure that any new or substantially changed Type B line complies with the design, installation, construction, and initial testing and inspection requirements for transmission lines and, if of metallic construction, comply with the corrosion control requirements for transmission lines. Operators must also include Type B gathering lines in their damage prevention and public education programs, establish the MAOP of those lines under § 192.619, and comply with the requirements for maintaining and installing line markers that apply to transmission lines.

**Comments:** The Texas Pipeline Association (TPA) suggested that if PHMSA decided to move forward with the proposal to survey Type B lines, then several topics would need to be addressed to assure the reasonableness of the proposed regulation. TPA suggested that:

- PHMSA share any supporting information provided by NAPSRS to show that leaks are the primary hazard for Type B gathering pipelines;

- Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 requires the Secretary of Transportation to review the existing Federal and state regulations for gathering pipelines to determine their sufficiency to ensure the safety of such lines. As such, PHMSA should not move forward with additional regulatory requirements for Type B gathering lines since Congress has mandated a review of the sufficiency of existing regulations;
- The docket contains no supporting evidence to show that the proposed amendment is based on facts and not speculation;
- Excavation damage may pose a greater risk than leaks in Type B gathering lines;
- PHMSA should develop estimates of the cost of compliance for affected operators;
- The economic impact may exceed the threshold for a non-significant regulatory action; and
- If PHMSA implements the change, it must provide at least one year adequate time for affected operators to purchase leak detection equipment, establish leak survey routes, develop recordkeeping systems for these surveys and hire additional personnel following adoption of the new leak survey equipment.

The Iowa Utilities Board (IUB) commented that the proposed amendment appears responsive to NAPS Resolution 2006-3, which called for the reinstatement of leak surveys that were not included when requirements for Type B gathering lines were adopted in Amendment 192-102. The IUB further noted that the proposed amendment includes a second part that was not in the NAPS resolution. The language of the second

part reads: “and fix hazardous leaks that are discovered in accordance with §192.703(c).” “Fix” is hardly usual regulatory language and has no specified definition or usage history in Part 192. The IUB and MichCon DTE Energy suggested that PHMSA use alternate language that removes a nonstandard term and an unnecessarily complicated rule reference by simply saying “and promptly repair hazardous leaks that are discovered.”

The Northeast Gas Association suggested that PHMSA revise its proposal to require operators of Type B regulated gathering lines to apply leak survey methods in accordance with §192.723 which provides the leak survey requirements for low-stress pipelines with a MAOP of less than 20 percent specified minimum yield strength (SMYS).

**Response:** As for the comment that PHMSA should wait until its congressionally mandated review of existing regulations for gas and hazardous liquid gathering lines is complete, the study required by Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act requires PHMSA to study and report to Congress on:

(A) The sufficiency of existing Federal and state laws and regulations to ensure the safety of gas and hazardous liquid gathering lines;

(B) The economic impacts, technical practicability and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulation when compared to the public safety benefits; and

(C) Subject to a risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas and hazardous liquid gathering lines.

The need to include leakage surveys as a compliance activity was identified between the publications of the Supplemental Notice of Proposed Rule Making (SNPRM) titled: “Pipeline Safety: Gas Gathering Line Definition: Alternative Definition for Onshore Lines and Proposed Safety Standards,” published October 3, 2005; 70 FR 57536 [Docket No. RSPA-1998-4868; Notice 5], and the Final Rule of the same title published March 15, 2006; 71 FR 13289 [Docket No. PHMSA-1998-4868]. The inclusion of leakage surveys as a compliance action was not included in the Final Rule because it was beyond the scope of the SNPRM and the agency did not want to further delay the rulemaking. During its annual meeting in September 2006, NAPSRS also passed a resolution [NAPSRS Resolution 2006-3] requesting the regulatory change to Type B lines.

As for the comment that Type B leaks due to excavation damage may pose a greater risk, the annual Type B report data for calendar year 2011 indicated that there were 289 leaks eliminated or repaired by operators of onshore Type B gathering lines, with the leading cause of leaks being external. Excavation damage is and has been recognized as a high risk for Type B gathering lines. This point was elaborated on in the Gas Gathering Line Definition in the SNPRM (October 3, 2005; 70 FR 57536) and Final Rule (March 15, 2006; 71 FR 13289), and served as the basis for the compliance activities for Type B lines (damage prevention programs, placement of line markers, and

public awareness programs). This amendment will add one more recognized risk control activity required on Type B gathering lines.

Regarding the comment that PHMSA should estimate the costs of compliance, PHMSA performed a cost analysis by averaging the daily rate of two leak survey service providers. The average cost of surveying two miles of pipeline per day equaled \$600. The estimated that approximately 3,650 miles of Type B gathering lines will be required to be inspected annually at an average cost of \$300 per mile for an upper bound annual cost of approximately \$1.1 million.

However, leak surveys, while not currently required for Type B gathering lines, are a widespread industry practice because they serve a business purpose in helping to detect leaks, thereby reducing lost gas and liability exposure. Although operators do not submit data on the extent of these surveys, PHMSA believes that approximately half of all Type B gathering line mileage that would otherwise be affected by this proposal is already being inspected. This is based on the fact that this is a widespread industry practice and until 2006, this was an existing regulatory requirement. Therefore, a more realistic estimate of the actual incremental cost is approximately 50% of the upper bound of \$1.1 million, or \$0.55 million per year.

The Northeast Gas Association, in a comment on PHMSA's published NPRM, noted there were operational similarities between Type B gathering lines and gas

distribution lines that operate at similar, lower pressures, and requested PHMSA apply leak survey standards to Type B gathering lines that were more in line with leak survey standards for distribution lines, rather than leak survey standards for transmission lines.

Title 49 CFR § 192.706 requires transmission line leak surveys at intervals not exceeding 15 months, but at least once each calendar year, and more frequently in densely populated areas. NAPSRS believes that Type B gathering lines should be subject to the same requirements, as Type B gathering lines can carry gas that is corrosive, and gas leaks are a significant hazard on those low-stress pipelines. Therefore, requiring leak surveys on Type B gathering lines is an appropriate and necessary risk-management measure.

NAPSRS also noted in their comments that some Type B gathering lines are located under broad paved areas, where electrical surveys that detect pipe damage may be difficult to perform, and leaking gas can migrate under the pavement and accumulate in surrounding structures. NAPSRS recommends that leak detection surveys should be required to ensure the safety of these lines.

As it stands, distribution lines in business districts must be surveyed each calendar year, with the remainder of distribution lines subject to leak survey at frequencies driven by local conditions but at an interval that does not exceed 5 years. Distribution lines, per the regulations, are required to be odorized which provides members of the public with a warning system for the period between surveys. The gas in gathering lines is un-

odorized, so the public does not have any advance warning of line leaks outside of those leak surveys. Leak surveys would serve as the warning bell.

Regarding the concerns raised by commenters about the cost of this proposal, under the current regulations, Type B gathering lines are treated the same as transmission lines for design, installation, construction, and initial testing and inspection. If the line in question is composed of metal, the line must also comply with the same corrosion control requirements as transmission lines. Similar to transmission lines, Type B gathering lines must be included in damage prevention and public education programs, have established MAOPs under § 192.619, and comply with the requirements for installing and maintaining line markers.

Because Type B gathering lines are regulated with many of the same requirements as transmission lines, it would follow that Type B gathering lines and transmission lines have a similar risk profile. Therefore, because transmission lines are subject to annual leak surveys, Type B gathering lines should be subject to the same requirement for safety reasons.

While leak surveys are not currently required for Type B gathering lines, they are a widespread industry practice that help operators detect leaks early and avoid loss of lives, gas and liability exposure. When this voluntary practice becomes a regulation it will provide a standard and consistent level of safety to the American public and ensure the integrity of these lines.



Taking this into consideration, as well as the GPAC's recommendation and the evaluation of public comments, PHMSA has adopted §192.9(d)(7) as proposed with the minor modification of substituting the word "fix" with "repair."

**(3) Qualifying Plastic Pipe Joiners § 192.285(c).**

**Proposal:** Section 192.285 contains requirements for qualifying persons to make joints in plastic pipe. Under § 192.285(c), "[a] person must be re-qualified under an applicable procedure, if during any 12-month period that person: (1) does not make any joints under that procedure; or (2) has three joints or three percent of the joints made, whichever is greater under that procedure that are found unacceptable by testing under § 192.513." In its petition to amend the regulations (2008-03-AC-1), NAPSR noted that the current rule, with its 12-month time period, requires detailed records of each individual joiner's activities and sets the stage for requalification date "creep," where a joiner must requalify at an earlier date every year. NAPSR commented that the existing regulatory language sets a very low standard for joiner requalification and noted that the large number of operators requesting similar waivers demonstrates that a requalification system like the one proposed in its resolution is acceptable and preferred by pipeline operators.

In the NPRM, based on the NAPSR petition, PHMSA proposed to revise § 192.285 to provide greater scheduling flexibility and require requalification of a joiner if any production joint is found unacceptable.

**Comments:** Center Point Energy (CPE) noted that it is overly excessive to disqualify and retrain a joiner if one joint is found unacceptable during a 12-month period. CPE suggested that PHMSA leave § 192.285(c)(2) as written and that quality assurance/quality checks of potentially unacceptable joints be accomplished through §192.513 testing. CPE also queried whether PHMSA has data from a study to show that an individual who makes one unacceptable joint will make more. City Utilities of Springfield, Missouri, suggested that we amend the language to clarify that requalification is necessary only if the joint failure is due to operator error.

Nicor Gas (Nicor), while supporting the proposal to add a three-month grace period in the requalification interval, does not support the proposed revision that would require requalification of the joiner if one joint is found unacceptable by the required pressure testing. Nicor commented that the proposal is unnecessarily restrictive and not validated or supported by documentation from NAPS. Nicor noted that there are field conditions and/or circumstances beyond the joiner's control (rain, snow, blowing dirt, trench cave-ins, equipment malfunctions and material flaws) that would affect the joining process without reflecting a lack of skill or proper training. All these incidents may lead to an unacceptable joint.

TPA also disagrees with the proposal to impose a zero-failure tolerance standard for plastic pipe joiners and commented that perfection in the performance of any task in any industry 100 percent of the time is rarely, if ever, achieved. TPA commented on the contrast of the regulations in plastic joining versus welding of steel pipelines and noted

that the existing regulations for welders do not impose a zero-tolerance standard, even though most steel pipelines operate at higher pressures than plastic pipelines, and would pose a higher safety risk to the public. The zero tolerance proposal for plastic pipe joiners also fails to consider that all plastic pipe is required to be pressure tested before going into service and that this testing provides an additional layer of safety assurance that plastic pipe joints are safe before pipeline operation begins.

AGA suggested that PHMSA analyze data on fusion failures, present the information to the public and then determine how best to address the issue. AGA further commented that the amendment to prohibit the entire crew from further fusion after one joint failure until requalification occurs seems unnecessarily severe, is unsupported by statistical evidence and has the potential to create unexpected adverse consequences.

**Response:** PHMSA reviewed the comments received on the topic including those that raised concerns of, and requested clarification on, the changes surrounding requalification if one joint is found unacceptable. PHMSA understands some of the concerns may have been related to the language used in the preamble and additional clarification may be needed regarding PHMSA's intent. PHMSA does not believe the proposed requirements are as onerous as some of the commenters indicated, nor would there necessarily be a zero tolerance policy in effect as a result of the proposed changes. PHMSA agrees there could be a number of factors including some beyond the joiners control such as weather, equipment malfunctions and material flaws, which could result in an unacceptable joint. However, PHMSA expects some evaluation would be done following any

unacceptable joint, and in some cases evaluation may be necessary on a case-by-case basis. If an unacceptable joint is a result of a factor(s) clearly beyond the joiner's control, PHMSA does not expect those conditions to affect the requalification of the joiner. Likewise, if an individual fusing a joint realizes that it is a bad joint, cuts it out, and fuses another (acceptable) joint immediately following, PHMSA does not expect that the joiner would have to requalify. On the other hand, if an unacceptable joint is related to issues that are within the joiner's control, that joiner would need to be re-qualified. While PHMSA has presented some general expectations, ultimate determination of the adequacy of an acceptable joint, whether or not the joiner would need to be requalify, and what may constitute an adequate qualifying joining test would be up to which ever entity inspects the joint. In most cases, particularly for intrastate systems, it would be up to the individual state.

In response to the comments regarding the burden of this provision, PHMSA notes that the changes may help reduce some of the current burden associated with the paperwork, tracking and record-keeping requirements that were associated with "three joints or three percent of the joints made, whichever is greater" in the current regulatory language. Regarding the comments inquiring about data or other studies surrounding joints, PHMSA is not aware of any studies showing that an individual who makes one unacceptable joint will make more. On the other hand, PHMSA is not aware of any data or studies that can guarantee that an individual who makes one unacceptable joint won't make another unacceptable joint. The potential safety issues surrounding an unacceptable joint those are not addressed through proper evaluation and requalification

seem to outweigh any benefit with continuing the qualification requirements as they currently exist in the regulations. Many of these and other aspects were discussed with the GPAC, the transcripts of which are available in the docket.

Following some discussion, the GPAC unanimously supported PHMSA's proposal that was based on the NAPS R petition. The PACs, industry and the public indicated that the original language in the regulations required numerous letters of interpretation and caused problems in the application of the regulations. The proposed language is also in keeping with some state waivers granted by PHMSA. Accordingly, the Final Rule revises § 192.285 to provide greater scheduling flexibility and require requalification of a joiner if any production joint is found unacceptable.

**(4) Mill Hydrostatic Tests for Pipe to Operate at Alternative Maximum Allowable Operation Pressure § 192.112.**

**Proposal:** Section 192.112 applies to pipe that will operate at the higher stresses allowed under the alternative MAOP permitted under § 192.620 and specifies additional design requirements. In the NPRM, PHMSA proposed to revise § 192.112(e) by eliminating the allowance for combining loading stresses imposed by pipe mill hydrostatic testing equipment for the mill test. Eliminating the allowance to combine equipment loading stresses will have the effect of increasing the internal test pressure for mill hydrostatic tests for new pipe to be operated at an alternative MAOP. This design requirement, combined with pipe mill dimensional checks for expansion, will help assure that all new

pipes to be operated at an alternative MAOP receive an adequate mill test and have adequate strength.

**Comments:** Evraz, a steel and pipe manufacturer, noted that eliminating the allowance for combining loading stresses imposed by pipe mill hydrostatic testing equipment could put mills that use testing processes that apply high end loadings at a competitive disadvantage to mills that do not. The amount of end loading applied depends on the testing process and equipment used. Mills that apply higher end loadings will produce combined stresses in excess of 100 percent SMYS if required to achieve 95 percent of SMYS based on gauge pressure alone. Evraz noted that the more effective way of addressing the potential of low strength line pipe would be to fully institute the changes in the 3<sup>rd</sup> addendum of the 44<sup>th</sup> edition of the American Petroleum Institute's (API), API Specification 5L, "Specification for Line Pipe," (API Spec 5L). TransCanada Corporation suggested that PHMSA consult with pipe manufacturers regarding the potential impacts of consideration of end loading in the calculations of mill hydrostatic tests before adopting changes to the procedure. TransCanada maintained that the increased safety factor was already added in the 2008 Final Rule titled: "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines" (73 FR 62148).

**Response:** Pipe mill hydrostatic testing is a factory proof test used to ensure that new pipe has no structural or manufacturing flaws and adequate strength. Section 192.112 applies to pipe that will operate at the higher stresses allowed under the alternative

MAOP rule. The mill test pressure of a minimum of 95 percent SMYS is being required to ensure that lower strength pipe is not used for alternative MAOP pipelines. The alternative MAOP rule allows pipelines to operate at stresses of up to 80 percent of SMYS, where other pipelines can only operate up to 72 percent SMYS. Pipelines that do not operate in accordance with the alternative MAOP must be mill tested as defined in the appropriate pipe manufacturing standard and the current edition of API Spec 5L incorporated by reference in § 192.7 (b)(7). The 45<sup>th</sup> edition of API Spec 5L was incorporated by reference on January 5, 2015 (80 FR 168). API Spec 5L offers a lower requirement than that of a mill test of 95 percent SMYS in § 192.112(e)(1) for non-alternative MAOP pipelines.

During the 2008 through 2010 construction seasons, PHMSA identified a number of cases where new pipe did not meet regulatory specified strength requirements. Pipe that is 15 percent below the mandated SMYS was found on several new pipeline construction projects. On May 21, 2009, PHMSA issued an advisory bulletin (ADB-09-01) Docket No. PHMSA-2009-0148 -- “Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe”), alerting pipeline operators of issues found with low strength pipe. Eliminating the mill test allowance to combine equipment loading stresses will have the effect of increasing the internal test pressure for mill hydrostatic tests for new pipe to be operated at an alternative MAOP. When combined with pipe mill dimensional checks for expansion, that change will help assure that all new pipes for this service receive an

adequate mill test and have adequate strength. This mill hydrostatic test criteria change will help to eliminate low strength pipe in alternative MAOP pipelines.

During 2009 to 2010, INGAA conducted two studies/white papers titled, “Guidelines for Evaluation and Mitigation of Expanded Pipes” dated June 9, 2010, and “Identification of Pipe with Low and Variable Mechanical Properties in High Strength, Low Alloy Steels” dated September, 2009 (Docket No. PHMSA-2010-0026). The INGAA studies confirm that if the mill hydrostatic pressure test produced a stress of 95 percent or more of SMYS, and diameter dimensions were taken at intervals along the length of each joint in addition to the required end dimension measurements, expansion of the pipe beyond the set tolerances in the pipe specification did not occur. If unacceptable expansion has occurred, those pipe joints can be identified and eliminated.

Since steel and pipe production are worldwide manufacturing processes, it is very difficult to determine that a standard quality assurance process has been fully implemented. Mill hydrostatic tests are the final quality assurance process in the pipe manufacturing chain. They are conducted by the pipe manufacturer and have the full quality assurance review of the pipe manufacturer and pipe purchaser/pipeline operator. This new requirement is based upon an INGAA sponsored industry review of pipe making practices. If pipe is not tested to a higher pressure in the mill then the low strength pipe will create operational concerns in the field. The adoption of this



amendment should expose low strength pipe in operation. Thus, PHMSA has adopted § 192.112(e) as proposed.

#### **(5) Regulating the Transportation of Ethanol by Pipeline § 195.2**

**Proposal:** In the NPRM, PHMSA proposed to modify its definition of “hazardous liquid” to include ethanol. This action was based in part on a policy statement published in the Federal Register on August 10, 2007; 72 FR 45002 (Docket Number: PHMSA-2007-28136) on the transportation of ethanol, ethanol blends, and other biofuels by pipeline. PHMSA noted in the policy statement that the demand for biofuels was projected to increase as a result of several Federal energy policy initiatives, which would result in greater use of pipelines for transporting biofuels. PHMSA also stated that ethanol and other biofuels are substances that “may pose an unreasonable risk to life or property” within the meaning of 49 USC 60101(a)(4)(B), and accordingly, these materials constitute “hazardous liquids for purposes of the pipeline safety laws and regulations.” PHMSA went on to say that the agency was considering a possible modification to § 195.2 to include ethanol and biofuels in the definition of hazardous liquid. PHMSA invited comments on that proposal and on other issues related to the transportation of biofuels by pipeline.

**Comments:** Thomas Lael Services, L.P., suggested that the term “ethanol” and “bio-diesel petroleum” should be added to the definition of “hazardous liquid.” AOPL added that rather than having another Federal agency or a number of state agencies attempt to regulate the safety of pipeline transportation of ethanol, that denatured ethanol be defined

as a “hazardous liquid” under § 195.2, so that ethanol transported via pipeline is regulated consistently with other energy liquids by PHMSA under 49 CFR Part 195.

**Response:** After evaluating the comments on the proposal, PHMSA has adopted the amendment to add the term “ethanol” to the definition of “hazardous liquids” in § 195.2. In this Final Rule PHMSA will not adopt the commenter’s suggestion that we add “bio-diesel petroleum” to the definition because this request is outside of the scope of this rulemaking. However, PHMSA may address this issue in a future rulemaking.

#### **(6) Limitation of Indirect Costs in State Grants § 198.13**

**Proposal:** PHMSA reimburses the states for a portion of the costs accrued in administering their pipeline safety programs and Congress appropriates the funds used to make these reimbursements on a regular basis. The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act) removed a provision that imposed a 20 percent cap on indirect expenses allocated to the pipeline safety program grants. In the NPRM, PHMSA proposed to incorporate the 20 percent limitation on indirect expenses into the regulations governing grants to state pipeline safety programs.

**Comments:** PHMSA received several comments opposed to this proposal. IUB and NAPSRS objected to the proposal to limit the indirect cost rate that can be recovered through a state’s pipeline safety grant to 20 percent. They both stated that the limit is arbitrary and capricious and may prevent the recovery of legitimate costs of state participation in the Federal/state pipeline safety program. IUB said the 20 percent limit is

not mandated by law or by any referenced Federal grant guide material or requirement. IUB also noted that there was no clear rationale as to why PHMSA should impose a requirement by rule that Congress found unnecessary and removed from law when the PIPES Act was passed in 2006. IUB and NAPSRS noted that different states have different methods of allocating costs within their budget and no basis was presented for punishing states that distribute a larger portion of their costs as indirect costs. NAPSRS is concerned that states could artificially inflate indirect costs to receive a larger grant payment.

PACs' members pointed out that the way in which states do their budgeting and accounting varies and some states do have indirect costs that exceed the 20 percent limit. However, because of the 20 percent required cost share, states do not present their costs that are above that threshold. Some state representatives noted that their indirect cost submissions are required to be approved first at the Federal level and are highly scrutinized to ensure no padding is done. In addition to that, to ensure compliance, PHMSA performs frequent audits of the state programs.

**Response:** PHMSA has decided not to adopt the proposal into regulation. However, PHMSA will maintain the 20 percent indirect cost cap through language in our payment agreements with states. As part of its state program, PHMSA has payment agreements with each state. These agreements are binding and cap indirect costs at 20 percent.

**(7) Transportation of Pipe § 192.65**

**Proposal:** Section 192.65 states that if pipe is to be transported by railroad, it will be operated at a hoop stress of 20 percent or more of SMYS, and has a diameter-to-wall-thickness ratio of 70 to one or more; the pipe must be transported in accordance with API RP 5L1. An exception is provided for certain pipe transported before November 12, 1970. That exception allows operators to use pipe stockpiled prior to the effective date of the original pipeline safety regulations, the transportation of which cannot be verified under API standards.

Based on an NTSB investigation and recommendation resulting from an Enbridge pipeline incident that took place on July 4, 2002, near Cohasset, Minnesota, PHMSA proposed to revise the regulation to require that the rail transportation of all pipe be subject to the referenced API standards.

**Comments:** We received several comments, including one from the NTSB in support of the proposal. The Committee on Pipe and Tube Imports (CPTI) Ad Hoc Large Diameter Line Pipe Producers Group agreed that the proposal would not have an adverse impact on operations or the ability to manufacture products. El Paso Pipeline Group (EPPG) commented that if PHMSA promulgates this amendment, it should specify that the use restriction does not apply to any pipe already installed, or to any pipe transported after § 192.65 initially took effect. EPPG commented that the proposed wording may result in misinterpretation and unintended consequences, such as assuming that “use” applies to pipe currently installed rather than to pipe in stock, and that shipping records must be

provided for all pipe exceeding the specified diameter-to-wall thickness ratio. EPPG proposed this rewording of the regulatory language:

“(a) Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe shipped by rail prior to November 12, 1970, unless the operator can show that the transportation was performed in a manner that meets the requirements of API RP 5L1.”

NAPSR agrees that any remaining stock of such pipe is likely to be minimal.

**Response:** Surveys conducted by INGAA failed to find any vintage pipe covered by § 192.65(a)(2). Therefore, PHMSA has no reason to continue the exemption and is removing this exemption from the regulation and adopting the amendment with one minor change. PHMSA is replacing the phrase “operator may not use pipe” with the phrase “operator may not install pipe” to clearly indicate that this amendment does not apply to pipe already installed.

#### **(8) Threading Copper Pipe: § 192.279**

**Proposal:** Section 192.279 specifies when copper pipe may be threaded and refers to Table C1 of American Society of Mechanical Engineers (ASME) Standard ASME/ANSI B16.5. In a letter dated June 11, 2009, the Gas Piping Technology Committee (GPTC) advised PHMSA that Table C1 was deleted in the most recent version of the ASME/ANSI B16.5, which is incorporated into Part 192 by reference. The GPTC stated that the information in Table C1 was taken from a different standard and that ASME/ANSI B36.10M, “Standard for Welded and Seamless Wrought Steel Pipe,”

should be substituted as a more appropriate reference. PHMSA proposed to use “threaded copper pipe if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe as listed in Table 1 of ASME B36.10M, Standard for Welded and Seamless Wrought Steel Pipe.”

**Comments:** We received no public or PAC comments on this proposal.

**Response:** PHMSA is unable to incorporate ASME/ANSI B36.10M, “Standard for Welded and Seamless Wrought Steel Pipe” due to the standards availability requirement described in Section 24 of the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” (Public Law 112-90, January 3, 2012). Section 24 added a new public availability requirement for documents incorporated by reference after January 3, 2013. The law stated that beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an Internet Website.

This section was further amended on August 9, 2013. The current law continues to prohibit the Secretary from issuing a regulation that incorporates by reference any document unless that document is available to the public, free of charge, but removes the Internet website requirements (Public Law 113-30, August 9, 2013). PHMSA will address this proposal in a future rulemaking action.

### **(9) Offshore Pipeline Condition Reports §§ 191.27 and 195.57**

Proposal: In the NPRM, PHMSA proposed to remove §§ 191.27 and 195.57. Sections 191.27 and 195.57 require operators to submit a report to PHMSA within 60 days of completing the underwater inspections of pipelines in the Gulf of Mexico required by §§ 192.612(a), and 195.413(a).

Sections 192.612(a) and 195.413(a) no longer require operators to perform an underwater inspection of all pipelines in the Gulf and its inlets. (*See also* Pub. L. 102-508 (Oct. 24, 1992) (modifying the statutory mandate for underwater inspection, reporting and reburial of pipelines in the Gulf and its inlets). Rather, those regulations call for periodic, risk-based inspections of shallow-water pipelines. The filing of a written report within 60 days of completing all of those inspections is not consistent with such an action. Additionally, sections 192.612(c) and 195.413(c) require operators to file their electronic/telephonic reports with the National Response Center within 24 hours of discovering that a pipeline in those areas is exposed or a hazard to navigation, which is sufficient to meet PHMSA's current information collection needs.

**Comments:** PHMSA received no public comments on this proposal.

**Response:** PHMSA has adopted the proposal to repeal §§ 191.27 and 195.57.

### **(10) Calculating Pressure Reductions for Hazardous Liquid Pipeline**

#### **Integrity Anomalies § 195.452(h)(4)(i)**

**Proposal:** Section 195.452(h)(4)(i) specifies the actions that an operator of a hazardous liquid pipeline must take after discovering an immediate repair condition. One of those actions is a temporary reduction in operating pressure as determined under the formula provided in section 451.6.2.2 (b) of ASME/ANSI B31.4, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.” The particular focus of that pressure reduction formula is corrosion. However, corrosion is only one of the threats that could cause an immediate repair condition under § 195.452(h)(4)(i).

In a July 17, 2007, Final Rule (72 FR 39017), PHMSA sought to modify § 195.452(h)(4)(i) to provide for alternative methods of calculating a pressure reduction for immediate repair conditions caused by threats other than corrosion. The Office of the Federal Register was unable to incorporate that change due to inaccurate amendatory instructions. In the NPRM, PHMSA again proposed to revise § 195.452(h)(4)(i) to make the same change as published in the July 17, 2007, Final Rule, with corrected amendatory instructions.

**Comments:** In response to our proposal, the TransCanada Corporation commented that it acknowledges the limitations of the current language in § 195.452(h)(4)(i) and believes a revision to the language in this section is appropriate. However, since § 195.452(h)(4)(i)(B) provides for the calculation of the remaining strength using methods that include, “but are not limited to,” ASME/ANSI B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines,” (ASME/ANSI B31G) or AGA Pipeline Research Committee, Project PR-3-805, “A Modified Criterion for Evaluating the



Remaining Strength of Corroded Pipe,” (PR-3-805 (RSTRING)), they do not believe a reference to the design requirements of § 195.106 is necessary. TransCanada commented that the ability to use alternative methods for calculating a pressure reduction would be incorporated with only a reference to § 195.452(h)(4)(i)(B). They suggested the following language in lieu of what PHMSA has proposed:

§ 195.452(h)(4)(i): “Immediate repair conditions. An operator’s evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety an operator must provide for immediate repair conditions. To maintain safety an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the criteria in paragraph (h)(4)(i)(B) of this section. If no suitable remaining strength calculation method can be identified, a minimum 20 percent or greater operating pressure reduction must be implemented until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions.”

The AOPL commented that the proposed language requiring the calculation of pressure reductions for detected anomalies should be modified to appropriately reference suitable calculation methods.

API noted that § 195.452(h)(4)(i)(B) already allows the use of PR-3-805 (RSTRENG), modified PR-3-805 (RSTRENG), or a suitable alternative remaining strength calculation method to be used, and therefore already fully covers the calculation of a temporary reduction in operating pressure. The API suggests that the following sentence in the proposed section is redundant: “If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure.”

The LPAC suggested the following language:

§ 195.452(h)(4)(i): “Immediate repair conditions. An operator’s evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formulas referenced in paragraph (h)(4)(i)(B) of this section. If no suitable remaining strength calculation method can be identified, a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two months prior to the date of inspection, must be implemented until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions: [...]”

**Response:** PHMSA believes both commenters were trying to make similar changes. In the Final Rule, PHMSA is adopting LPAC’s suggested language as it best clarifies that an operator must calculate remaining strength or reduce operating pressure until a repair can be completed.

**(11) Testing Components other than Pipe Installed in Low-Pressure Gas Pipelines § § 192.503 and 192.505**

**Proposal:** In the NPRM, PHMSA proposed to amend §§ 192.503 and 192.505 to exempt certain components from the strength test requirement in Subpart J of Part 192. This proposal was based on a petition from the GPTC in a letter dated March 25, 2010. The GPTC argued that the primary purpose of a post-installation strength test is to prove the integrity of the entire pipeline system. The GPTC further noted that the most important parts to check of a single-component replacement are the joints that connect the component to the pipeline, and that these joints are currently exempted from testing for all gas pipelines by paragraph (d) of § 192.503.

**Comments:** PHMSA received many comments in support of this proposal. We also received some comments asking that we expand the list and sources of standards that can be used to establish pressure ratings. One commenter asked that we review all referenced standards and provide exemptions for all standards that establish pressure ratings.

**Response:** PHMSA is adopting the amendment as proposed. The request to expand the list and sources of standards that can be used to establish pressure ratings is out of the scope of this rulemaking, as is the request to review all referenced standards. Therefore, those requests have not been adopted but may be considered in future rulemaking actions.

**(12) Alternative MAOP Notifications § 192.620(c)(1)**

**Proposal:** Section 192.620(c)(1) currently requires a pipeline operator to notify each PHMSA pipeline safety regional office where the pipeline is in service of its election to use an alternative MAOP pressure with respect to a segment at least 180 days before operating at the alternative pressure. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.

PHMSA proposed to require that for new pipelines, an operator would notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operations 180 days prior to start of pipe manufacturing or construction activities. An operator would also notify state pipeline safety authorities when the pipeline is located in

a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.

PHMSA also proposed to revise § 192.620(c)(8) to correct a typographical error related to the reference to § 192.611(a).

The proposal to require 180 day notice for new pipelines was to allow sufficient time for PHMSA to conduct any needed material manufacturing and construction inspections, including checks of new pipe rolling and coating processes, visit the new pipeline field sites during construction, analyze operating history of existing pipelines, and review test records, plans, and procedures.

**Comments:** INGAA suggested that the proposal should apply only prospectively, that the regulation should include an alternative notice period measured from the placement of the pipe purchasing order to the start of pipe manufacturing and that the language needs clarification with regard to new pipe. In its comments to the NPRM, INGAA noted that for new pipeline projects the application and permitting process can extend over months or years before approval to construct is granted. Once this approval is obtained, pipe orders are placed and production dates are established. The interval from the time the pipe is ordered until the start of production is sometimes less than 180 days making it impractical to provide the required notice as the proposed rule is currently worded. To address this INGAA recommends that the wording be changed to 180 days or 10 business days before the operator places a purchasing order for the pipe or the pipe starts being manufactured.

Panhandle Energy (Panhandle) recommended that the wording addressing new pipelines be changed to: “For new pipelines, notify the PHMSA pipeline safety regional office 180 days prior to the start of pipe manufacturing and/or construction activities, if practicable, but no more than 10 business days after the operator places an order for the pipe or executes the pipeline construction contract.”

TPA commented that if the operator wishes to utilize the existing pipe stock that satisfies the MAOP regulation requirement, the 180 day notice to the manufacturer would be impossible, and that the language should be revised to remove “and/or” to provide clear, unambiguous standards.

**Response:** PHMSA evaluated the comments and believes the proposed 180 days notification is too restrictive. Notification to PHMSA of new alternative MAOP pipeline project activities at least 60 days prior to start of pipe manufacturing or construction activities should not delay operator project activities. PHMSA needs this time to schedule personnel for safety inspections at both the pipe and coating mills and at the construction site prior to the start of pipe construction activities. PHMSA will require a 60 day notice by the operator prior to the start of pipe manufacturing or construction activities of new alternative MAOP pipelines.

**(13) National Pipeline Mapping System §§ 191.29, 195.61**

**Proposal:** The National Pipeline Mapping System (NPMS) is a geospatial dataset that contains information about PHMSA-regulated gas transmission pipelines, hazardous liquid pipelines, and hazardous liquid low-stress gathering lines. The NPMS also contains data layers for all liquefied natural gas plants and a partial dataset of PHMSA-regulated breakout tanks.

In the NPRM, PHMSA proposed to codify the statutory requirement for the submission of the NPMS data into Parts 191 and 195. An NPMS submission consists of geospatial data, attribute data and metadata, public contact information, and a transmittal letter.

PHMSA also proposed to require operators to follow the submission guidelines and dates set forth in the July 31, 2008, advisory bulletin (73 FR 44800: Pipeline Safety; National Pipeline Mapping System). Gas transmission operators and liquefied natural gas (LNG) plant operators would make their NPMS submissions on or before March 15, representing their assets as of December 31 of the previous year. Hazardous liquid operators would make their NPMS submissions on or before June 15, representing their assets as of December 31 of the previous year.

**Comments:** Oleska commented that, though they agree that the requirements should be added to Part 191, requiring operators to report to both NPMS and PHMSA is unduly burdensome and is not necessary. The TPA asked that PHMSA revise the language to clarify that this proposal only covers hazardous liquid trunklines and regulated rural hazardous liquid gathering pipelines as defined in the NPMS Operator Standards. TPA and Oleska noted that the operator ID for each operator is the same as it is for PHMSA, and that PHMSA should have the ability to get whatever information it needs directly

from the NPMS without operators having to submit two sets of data. TPA and Oleska suggested that it would be better for PHMSA to get its data from the NPMS, because two sets of data increase the chance of discrepancies, especially if changes are made between annual submissions.

**Response:** In response to TPA’s and Oleksa’s concern about submitting the data twice, operators will continue to make only one NPMS submission following the guidelines in the NPMS Operator Standards Manual on the NPMS website ([www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov)). This Final Rule imposes no additional submission requirements. In response to the concern about the NPMS’s and PHMSA’s capability to process all the gas, LNG plant operator and liquid operator submissions received on or before March 15 and June 15, respectively, PHMSA encourages operators to make their submissions early beginning on January 1 of each year. In the Final Rule, PHMSA is adopting the amendment to the NPMS as proposed.

**(14) Welders vs. Welding Operators §§ 192.225, 192.227, 192.229, 195.214, 195.222**

**Proposal:** The welding provisions in Subpart E of Part 192 and Subpart D of Part 195 allow qualification of welders in accordance with API Standard 1104, “Welding of the ASME Pipelines and Related Facilities,” (API Std 1104), section 6 or ASME Boiler and Pressure Vessel Code., section IX: “Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators,” (ASME BPVC, section IX). In the NPRM, PHMSA proposed to add references to additional qualification standards in API Std 1104, such as sections 12 and 13 for welders and

welding operators of mechanized and automated welding equipment. The addition of these qualification references was intended to follow current industry practice. These standards have specific processes to ensure that qualified personnel are used for welding processes whether they are performed by welders or welding operators.

**Comments:** EPPG commented that the proposed language appears to not allow for the qualification of a welding operator whose welds are regularly being assessed per the criteria in API Std 1104, Appendix A, which is regarded as being equivalent to section 9. EPPG suggested a revision of the proposed language of §192.227(a) to read: “under section 6, ~~or~~ section 9 or Appendix A, as applicable of API Std 1104 (incorporated by reference, *see* §192.7).” [Proposed deletion indicated by ~~strikeout~~; proposed addition in bold].

INGAA recommended that while PHMSA is amending the welding regulations, PHMSA should take the opportunity to formally incorporate by reference Appendix B to API Std 1104 for in-service (also known as “live line”) welding. Oleska suggested that the language of the proposed revision would be clearer if we changed “pipe and components” to read “pipe or components.”

Panhandle commented that the proposed language for § 192.229(c)(1) contains an oversight related to this equivalence. The section says, in part:

A welder or welding operator qualified under § 192.227(a) ---

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding six calendar months the



welder or welding operator has had one weld tested and found acceptable under section 6 or section 9 of API Std 1104 (incorporated by reference, *see* § 192.7).

According to Panhandle, sections 6 and 9 of API Std 1104 relate to workmanship criteria only. The proposed language would appear to exclude qualification of a welding operator whose welds are regularly being assessed per the criteria in API Std 1104, Appendix A which is regarded as being equivalent to ASME BPVC, section IX. It is reasonable to allow qualification for a welding operator whose work has been acceptable under the Appendix A criteria. Panhandle therefore suggested that PHMSA modify the proposed language in the notice to read:

“A welder or welding operator qualified under § 192.227(a) may not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under section 6, section 9 or Appendix A of API Std 1104, as applicable (incorporated by reference, *see* § 192.7).”

**Response:** The Final Rule allows welds to be evaluated to API Std 1104, section 9 or Appendix A, and eliminates the requirement that the weld be first evaluated to section 9, before using Appendix A. Evaluating the welds first according to section 9 incurs unnecessary time and cost without any benefit.

PHMSA re-evaluated its proposal to add additional references to qualification standards in API Std 1104. PHMSA finds that adding API Std 1104, section 13

(“Automatic Welding Without Filler Metal Additions”) is inconsistent with pipeline safety. API Std 1104, section 13 is not used on regulated pipelines and would be a major change in girth welding standards. Also, for practical purposes, there are no commercially used pipeline welding systems in the United States to which API Std 1104, section 13 can be applied. Not adopting API Std 1104, section 13, will prevent an operator from using a potentially less safe welding system without a PHMSA special permit review.

INGAA suggested that PHMSA use the Final Rule as an opportunity to formally incorporate by reference Appendix B to API Std 1104 for in-service (“live line”) welding. Parts 192 and 195 currently require that all welding procedures be qualified to API Std 1104, section 5 or ASME BPVC, section IX, and that all welders be qualified to API Std 1104, section 6 or ASME BPVC, section IX. API Std 1104, Appendix B is only applicable to in-service welds on live or “hot” pipelines, with pressurized product in the pipe. The qualification requirements of Appendix B are optimized for in-service welds, and differ greatly from API Std 1104, sections 5 and 6 and ASME BPVC, section IX. Thus, adding API Std 1104, Appendix B to the Final Rule is a significant change that is outside the scope of this rule. We will consider this change for a future regulatory action.

Based upon further review by PHMSA of Part 192, Appendix C, PHMSA decided that adding welding operators for Appendix C qualification in § 192.227(b) would be inappropriate for the following reasons:

- 1) Qualification of welding operators can be, and is more appropriately performed to API Std 1104, section 12, instead of Appendix C;
- 2) Appendix C is primarily used for lower pressure, smaller diameter distribution lines, which are welded by welders, not welding operators; and
- 3) The language in Appendix C was written for qualification of welders, and may not be appropriate for qualification of welding operators.

We agree with the comments that API 1104, Appendix A should be included as a qualification reference. When we proposed to add the relevant references to welding qualification standards to be consistent with industry practice, we intended to include the Appendix A reference, a widely accepted standard. Appendix A is now cited in the final regulations applicable to welding and welding operators.

#### **(15) Components Fabricated by Welding § 192.153**

**Proposal:** Pressure vessels can be found in meter stations, compressor stations and other pipeline facilities to facilitate the removal of liquids and other materials from the gas stream. These vessels are designed, fabricated and tested in accordance with the requirements of ASME Boiler & Pressure Vessel Code, section VIII Rules for Construction of Pressure Vessels,” as required by § 192.153 and § 192.165(b)(3), and the additional test requirements of § 192.505(b).

In the NPRM, PHMSA proposed that because the standard ASME pressure vessel test in ASME BPVC, section VIII, division 1 is 1.3 times MAOP, an operator must

specify the correct test pressure when placing an order for an ASME vessel to ensure it is designed and tested to the requirements of 49 CFR Part 192. Unless a vessel is specially ordered with a test pressure of 1.5 times MAOP as prescribed by the purchaser, the vessel will be tested in accordance with the standard test factor of 1.3. If the vessel is not tested to 1.5 times the MAOP, it cannot be used in a compressor or meter station, or other Class 3 or Class 4 locations. The failure to meet this requirement can potentially lead to exceeding the design parameters of the vessel during subsequent testing of the pipeline system.

The pressure test requirements in ASME BPVC, section VIII were lowered from a test factor of 1.5 to 1.3 by an earlier edition. PHMSA proposed to add § 192.153 to clearly specify the design and test requirements for pressure vessels in meter stations, compressor stations, and other locations that are tested to Class 3 requirements. Under the proposal, all ASME pressure vessels subject to § 192.153 and § 192.165(b)(3) would be designed and tested at a pressure that is 1.5 times the MAOP, in lieu of the standard ASME BPVC, section VIII test pressure of 1.3 times the MAOP. Additionally, PHMSA proposed to revise § 192.165(b)(3) reference to this requirement.

**Comments:** Kern River, INGAA and Northern Natural Gas maintained that this proposal is not a simple clarification but a change from the previous understanding and practice of both PHMSA and the operators. If the proposed regulation is applied retroactively, this change will place many facilities constructed after the change in the pressure test requirements in ASME BPVC, section VIII, as well as many facilities uprated under special permits, in violation of ASME BPVC, sections I and II. INGAA

noted that these sections of Part 192 and the ASME BPVC revision history make it clear that the proposed rule will require a number of operators to make substantial and costly changes. Northern Natural Gas commented that retesting and replacing of these in-service components would be unnecessary, very expensive, and take several years to complete.

INGAA noted that station piping often includes fabricated sections that are assembled at the construction site. Many of these sections, such as compressor bottles, coolers and inlet scrubbers and separators are tested and certified by their manufacturers. Requiring a second test at the construction site as proposed would depart sharply from common practice, add costs that are not justified by a safety benefit and potentially invalidate the manufacturers' compliance certificates.

Kern River further commented that station piping is commonly tested in several segments and it is not common practice to include and retest ASME code vessels since they are certified by the manufacturers and retesting would require dewatering. INGAA advised PHMSA to adopt an alternate clarification that these components do not require testing beyond the ASME code. If PHMSA adopts the current recommendation, it should clarify that the amendment applies to components placed into service after the amendment's effective date.

**Response:** PHMSA has incorporated by reference ASME BPVC for pressure vessels. The revised ASME BPVC, section VII, division 1 has changed pressure testing standards

from 1.5 times MAOP to 1.3 times MAOP. This proposal is not a change to the current pressure testing requirements found in Part 192, but simply a clarification to ensure a clearer understanding of PHMSA's pressure testing requirements for certain ASME BPVC vessels located in compressor stations, meter stations and other Class 3 or Class 4 locations. The pressure testing requirements for pipelines in the PSR (which by definition includes pressure vessels, meter stations, compressor stations and other facilities used to transport gas as defined in Part 192 and ASME/ANSI B31.8) in Class 3 and 4 areas, as well as those facilities located in Class 1 and Class 2 which are explicitly required by § 192.505(b), requires a pressure test equal to a minimum of 1.5 times the MAOP. The testing requirements of § 192.505(b) have not been revised and state that in a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements. This clarification of code requirements are to ensure that Industry does not incorrectly use the newer ASME BPVC standard for pressure testing even though that was never the requirement. This clarification will not lead to additional cost measures, and therefore, PHMSA is adopting this amendment as proposed.

**(16) Odorization of Gas Transmission Lateral Lines §192.625**

**Proposal:** Section 192.625 contains requirements for operators to odorize combustible gas in a transmission line in Class 3 or Class 4 locations “so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.” Certain exceptions are recognized by regulation, including for a lateral line, “which transports gas to a distribution center, [if] at least 50 percent of the

length of that line is in a Class 1 or Class 2 location.” This section does not specify a clear method for calculating the length of a lateral line, and that has led to inconsistencies in applying the odorization requirement. In the NPRM, PHMSA proposed to amend § 192.625(b)(3) to state that the length of a lateral line, for purposes of calculating whether at least 50 percent of the line is in a Class 1 or Class 2 location, be measured between the distribution center and the first upstream connection to the transmission line.

**Comments:** Texas Oil and Gas Association commented, and API supported this comment, that PHMSA’s attempt to better define which natural gas transmission lateral pipelines are subject to the odorization requirement may create the unintended consequence of adversely impacting industrial facility (refinery) operations and product quality in addition to increasing emissions. TransCanada Corporation noted that the proposed amendment’s apparent distinction between lateral and transmission lines appears to lack logic, as it allows parts of a line originally considered to be a “lateral” line to change classification due to introduction of a branch. TransCanada further noted that the industry is not aware of, nor has PHMSA presented in the preamble, statistical evidence that this understanding of lateral has caused safety issues resulting from operators applying this definition to exempt certain lines from odorization with commensurate safety benefits. TransCanada submits that the definition of “lateral” most commonly used by the industry more than adequately serves the interest of public safety. It also noted that “laterals are not distinct classification of lines; rather, ‘laterals’ are described according to their function (e.g., transmission, distribution or gathering).”

INGAA had similar comments and suggested that PHMSA convene a public hearing or workshop to develop the fundamental regulatory changes needed to align its policy objectives with common pipeline configurations. The natural gas industry considers lateral lines to be any lines that branch off other lines. Section 192.625 does not specify a clear method to calculate the length of a lateral line, and that has led to inconsistency in applying the odorization requirement. Even with the proposed language, there is confusion on the calculation. There is no evidence, of record or otherwise, suggesting that the industry's understanding of "lateral" has caused any safety issues.

The American Chemical Council (ACC) commented that the use of gas odorants at certain facilities could affect some chemical manufacturing processes and the quality of some chemicals. While there are well-established safety benefits of odorants in natural gas transmission that are fully consistent with the ACC member company interests in enhanced natural gas production and use, the ACC is concerned that the potential requirement to odorize lateral lines that carry natural gas may affect some industrial facilities. Further, the proposal could force chemical manufacturers to remove the odorant before processing, leading to a substantial potential increase in the effective cost of natural gas and in the cost of production.

TPA commented that this change could also result in odorization equipment, including odorant storage tanks, being located in close proximity to populated areas, increasing the likelihood of false reports and odor complaints from nearby residents.



According to TPA, some products manufactured with natural gas can be tainted by sulfur based odorant making the product worthless.

**Response:** This controversial topic was discussed at length at the advisory committee meeting. GPAC members found it difficult to agree on how to calculate the 50 percent length of a lateral line between the distribution center and the first upstream connection to the transmission line. Committee members were also concerned with the costs and benefits of this proposal. GPAC voted unanimously for PHMSA not to adopt this proposal. Although PHMSA believes that proper odorization is important, this proposal requires further analysis. Therefore, PHMSA will re-evaluate the proposal and may consider the revision in a future rulemaking action.

#### **(17) Editorial Amendments**

##### **A: Editorial amendments proposed in the NPRM:**

In the NPRM, PHMSA proposed several editorial amendments to the regulations.

1) In § 195.571, we proposed to revise the reference to NACE SP0169 to specify compliance with one or more of the applicable criteria contained in paragraphs 6.2.2, 6.2.3, 6.2.4, 6.2.5 and 6.3.

2) In § 195.2, we proposed to amend the definition of “Alarm” to correct an error in the codification of the new control room management regulations (74 FR 63310).

3) In §§ 192.925(b) and (b)(2), we proposed to replace “indirect examination” with “indirect inspection” to maintain consistency with § 192.925(a) and the applicable NACE standard.

4) In § 195.428(c), we proposed to replace “sections 5.1.2” with “section 7.1.2” to correctly reference the overfill protection requirements for aboveground breakout tanks in the API Std 2510.

5) In section 192.3 we proposed to add the definition of “Welder” and “Welding Operator.”

6) In § 195.2, we proposed to revise the definitions of “alarm” and “hazardous liquid.”

None of these editorial amendments received any comment and, as such, we are adopting them all as proposed.

#### B. Editorial amendments not proposed in the NPRM

Several administrative regulatory changes summarized in the following paragraphs are included in this Final Rule.

#### Hazardous Liquid Construction Notifications 195.64 (c)(1)(i)

PHMSA discovered an error in the hazardous liquid regulations covering operator notifications of planned construction, and gave notice of its intention to correct the regulatory language (*see* March 21, 2012; 77 FR 16472, Advisory Bulletin ADB-2012-04). Section 195.64(c)(1)(iii) requires notification for construction of a new

pipeline facility but does not specify a minimum dollar threshold for the construction project. Section 195.64(c)(1)(i) also requires notification for construction of a new pipeline facility, but only for those projects with a cost of ten million dollars (\$10,000,000) or more. PHMSA does not wish to be notified about hazardous liquid pipeline facility construction with a cost of less than ten million dollars, so § 195.64(c)(1)(iii) is being deleted.

### **Reporting and Notification Methods**

The NPRM proposed to remove the requirement to file offshore pipeline condition reports currently found in §§ 191.27 and 195.57. This Final Rule completes the removal and changes §§ 191.7 and 195.58 by removing the reference to offshore pipeline condition reports.

Sections 191.25 and 195.56 include the method for submitting safety-related condition reports. Since the receipt and processing of these reports is extremely time sensitive, the regulations currently require submittal by facsimile and do not provide an option for electronically mailing the report to PHMSA. These amendments are non-substantive and allow operators easier reporting methods. In this Final Rule, these regulations are revised to allow submittal of reports by electronic mail.

The remaining changes apply to the submittal methods for integrity management and operator qualification program notifications. Under changes made in this Final Rule, these notifications may now be submitted by either electronic mail or regular mail. For

integrity management, changes are made in §§ 192.949 and 195.452. For operator qualification programs, changes are made in §§ 192.805 and 195.505.

### Regulatory Analyses and Notices

#### Executive Order 12866, Executive Order 13563, and DOT Regulatory Policies and Procedures

This Final Rule is a non-significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735) and, therefore, was not reviewed by the Office of Management and Budget. This Final Rule is not significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034).

Executive Orders 12866 and 13563 require agencies to regulate in the “most cost-effective manner,” to make a “reasoned determination that the benefits of the intended regulation justify its costs,” and to develop regulations that “impose the least burden on society.” PHMSA amended miscellaneous provisions to clarify and eliminate unduly burdensome requirements. PHMSA also responded to requests from industry and state pipeline safety representatives to revise its regulations. PHMSA anticipates that a majority of the amendments contained in this Final Rule will have economic benefits to the regulated community by increasing the clarity of its regulations and reducing compliance costs.

For example, the changes related to NPMS and ethanol are simply a regulatory codification of current requirements. The elimination of the exception in §192.65 related to the transportation of pipe should have minimal impact because the amount of pipe that would be eligible for the exception is very small. The elimination of the offshore pipeline condition report will eliminate a reporting requirement that is no longer necessary.

Several provisions of the Final Rule are specifically designed to eliminate confusion and potentially lower costs for regulated entities. For example, the final addition of § 192.153(e) is designed to prevent regulated entities from purchasing pressure vessels that do not comply with § 192.505(b), but that do comply with ASME BPVC, section VII, as required by § 192.165(b)(3). The changes with respect to qualifying plastic pipe joiners will prevent re-qualification date “creep” and provide operators greater re-qualification flexibility and overall cost savings.

Annual Compliance costs associated with this rulemaking are estimated to be \$0.55 million, all of which are associated with requirement of leak Surveys for Type B gathering lines. PHMSA estimates approximately 3,650 miles of Type B gathering lines will be required to be inspected annually. PHMSA estimates that the average cost of inspection is \$300 per mile, bringing the upper bound limit of the total annual expenditure to approximately \$1.1 million. A more realistic estimate of the actual incremental cost is approximately 50% of the upper bound of \$.55 million.

By performing leak surveys annually, operators are more likely to detect leaks early, thereby avoiding costlier future repairs and reducing the amount of gas lost. There are also practical, operational benefits to conducting leak surveys, in the form of greater knowledge of the state of the pipeline, including potential third-party encroachments, soil erosion, or intrusion by vegetation.

The lead cause of these leaks is external corrosion. Leak surveys are particularly important for low pressure gas gathering lines because these lines tend to leak rather than rupture and because their gas is non-odorized, making leaks more difficult to detect. In addition to the direct operational benefits, annual leak surveys will also reduce the environmental harm caused by lost gas (i.e., the greenhouse gas potential of methane released into the atmosphere). Operator leak reporting also gives PHMSA valuable information that can be used in trending analysis for the determination of problem materials or poor operating practices. These important benefits cannot be readily quantified, but PHMSA believes that they are substantial.

In addition, eliminating these leak helps to ensure that leaked gas does not collect and lead a catastrophic explosion or other incident. Although fortunately there have been no serious incidents involving Type B gathering lines in the past several years, increased leak surveys would reduce the potential of a future incident. At an incremental cost of \$0.55 million per year, requiring annual leak surveys would be a cost-effective safety intervention if it prevents even a single fatal incident over a 16 year period.

A more thorough discussion of the subjects and the associated costs and benefits can be found in the Regulatory Impact Analysis, a copy of which has been placed in the Docket, PHMSA-2010-0026.

#### Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities.

#### Description of the reasons that action by PHMSA was taken.

PHMSA, pipeline operators and others have identified certain errors, inconsistencies, and deficiencies in the pipeline safety regulations concerning the following subjects: (1) performance of post-construction inspections; (2) leak surveys of Type B onshore gas gathering lines; (3) the requirements for qualifying plastic pipe joiners; (4) the transportation of ethanol by pipeline; (5) the transportation of pipe; (6) the filing of offshore pipeline condition reports and (7) the calculation of pressure reductions for hazardous pipeline anomalies. PHMSA is addressing these issues in this Final Rule.

#### Succinct statement of the objectives of, and legal basis, for the Final Rule.

Under the pipeline safety laws, 49 U.S.C. 60101 *et seq.*, the Secretary of Transportation must prescribe minimum safety standards for pipeline transportation and for pipeline facilities. The Secretary has delegated the authority of 49 CFR 1.53(a) to the PHMSA Administrator. The Final Rule would make changes in the regulations consistent with the protection of persons and property, while changing unduly burdensome or confusing requirements.

Description of small entities to which the Final Rule will apply.

In general, the Final Rule will apply to pipeline operators, some of which may qualify as a small business as defined in Section 601(3) of the Regulatory Flexibility Act. Some pipelines are operated by jurisdictions with a population of less than 50,000 people, and thus qualify as small governmental jurisdictions.

Some portions of the rule apply to manufacturers of pipeline components, as well as the contractors constructing or repairing a pipeline. Many of these may qualify as a small business entity.

Description of the projected reporting, recordkeeping, and other compliance requirements of the Final Rule, including an estimate of the classes of small entities that will be subject to the rule, and the type of professional skills necessary for preparation of the report or record.



The Final Rule does not directly impose any reporting or recordkeeping requirements. However, the rule creates an obligation to perform leak surveys of Type B gathering lines. This sort of survey is currently required of transmission lines. Professional technicians will be needed to comply with this requirement, and the time required for compliance will vary greatly with each system, depending on the system's size.

The remainder of the Final Rule does not impose any significant compliance, recordkeeping, or reporting requirements. However, it affects the timing and substance of one type of report that must be created and maintained under existing regulations. The Final Rule stipulates that operators notify PHMSA field offices 60 days prior to pipe manufacturing or construction activities on new alternative MAOP pipelines. The current regulations require operators to notify PHMSA 180 days in advance of operating a pipeline at a higher alternative MAOP. Because operators must currently provide PHMSA with a 180 day notice prior to operating at the alternative MAOP the Final Rule does not impose any additional reporting requirements.

Identification, to the extent practicable, of all relevant Federal rules that may duplicate, overlap, or conflict with the Final Rule.

PHMSA is unaware of any duplicative, overlapping, or conflicting Federal rules.

Description of any significant alternatives to the Final Rule that accomplish the stated objectives of applicable statutes and that minimize any significant economic impact of the Final Rule on small entities, including alternatives considered.

PHMSA is unaware of any alternatives which would produce smaller economic impacts on small entities while at the same time meeting the objectives of the relevant statutes. Several provisions of the Final Rule are specifically designed to eliminate confusion and potentially lower costs for regulated entities. For example, the addition of 49 CFR 192.153(e) is designed to prevent regulated entities from purchasing pressure vessels that do not comply with § 192.505(b), but that do comply with ASME BPVC section VII, as required by § 192.165(b)(3). PHMSA believes that this Final Rule impacts a substantial number of small entities but that this impact will be negligible. The one requirement that may have a significant cost impact on small businesses is leak surveys for Type B gas gathering lines. PHMSA estimates that requiring leakage surveys on Type B gas gathering lines will necessitate an annual expenditure of approximately 0.55 million dollars. The costs are based on surveying two miles of pipeline per day at an approximate daily cost of \$300 per mile and PHMSA's estimation that 50 percent of the mileage affected by this proposal already complies with the surveying. The daily costs are an average day rate provided by two providers of leak survey services.

The Small Business Administration's North American Industry Classification System Code for gas transmission pipeline operators defines a small business as those operators that have annual revenue of less than 25.5 million dollars. It is PHMSA's

opinion that very few gas gathering operators have revenues less than 25.5 million dollars per year. No other types of small entities, such as manufacturers, will see a significant cost impact. Therefore, this amendment will not affect a substantial number of small businesses. Based on the facts available about the expected impact of this rulemaking, I certify, under Section 605 of the Regulatory Flexibility Act (5 U.S.C. 605) that this Final Rule will not have a significant economic impact on a substantial number of small entities.

#### Executive Order 13175

PHMSA has analyzed this Final Rule according to the principles and criteria in Executive Order 13175, “Consultation and Coordination with Indian Tribal Governments.” Because this Final Rule does not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

#### Paperwork Reduction Act

This Final Rule imposes no new requirements for recordkeeping and reporting.

#### Unfunded Mandates Reform Act of 1995

This Final Rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It would not result in costs of \$100 million, adjusted for

inflation, or more in any one year to either state, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the Final Rule.

#### National Environmental Policy Act

The National Environmental Policy Act (42 U.S.C. 4321 – 4375) requires that Federal agencies analyze final actions to determine whether those actions will have a significant impact on the human environment. The Council on Environmental Quality regulations requires Federal agencies to conduct an environmental review considering (1) the need for the final action, (2) alternatives to the final action, (3) probable environmental impacts of the final action and alternatives, and (4) the agencies and persons consulted during the consideration process. 40 CFR 1508.9(b).

## 1. Purpose and Need

PHMSA's mission is to protect people and the environment from the risks of hazardous materials transportation. The purpose of this rulemaking change is to improve compliance, provide clarification, address conflicting language and promote improved pipeline integrity and safety. In addition the purpose is to address small gaps in the current regulations and mitigate some of the negative externalities that can result from industry market failures.

The need for this action stems from statutory requirements described in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Public Law 112-90), safety recommendations from the NTSB, and petitions from industry groups. In addition, due to shortfalls and unenforceability of industry standards, there arises a need for government to set minimum safety levels in pipeline regulations.

PHMSA is making amendments and editorial changes to the regulations that includes modifying the requirements for: the performance of post-construction inspections, the conducting of leak surveys of Type B onshore gas gathering lines, qualifying plastic pipe joiners, the regulation of ethanol, the transportation of pipe, the filing of offshore pipeline condition reports, and the calculation of pressure reductions for hazardous liquid pipeline anomalies.

## 2. Alternatives

In developing the Final Rule, PHMSA considered three alternatives:

- (1) No action.
- (2) Adopting all proposed amendments.
- (3) Adopting all proposed amendments except for leak surveys for Type Gas gathering lines.

Alternative 1:

PHMSA has an obligation to ensure the safe and effective transportation of hazardous liquids and gases by pipeline. The changes in this Final Rule serve that purpose by clarifying the regulations and eliminating unduly burdensome requirements. A failure to undertake these actions would allow for the continued imposition of unnecessary compliance costs without increasing public safety. Accordingly, PHMSA rejected the no action alternative.

Alternative 2:

PHMSA's Selected Action is a set of amendments and editorial changes to the Federal Pipeline Safety Regulations (49 CFR parts 191, 192, and 195). These revisions would eliminate inconsistencies and respond to several petitions for rulemaking and recommendations from our stakeholders, thereby facilitating the safe and effective transportation of hazardous liquids and gases by pipeline. The changes in this Final Rule will serve that purpose by clarifying certain regulatory requirements.

### Alternative 3:

As discussed above under alternative 2, and in the published NPRM, PHMSA proposed to make certain amendments, corrections and editorial changes to the regulations. These revisions eliminate inconsistencies and respond to several petitions for rulemaking and recommendations from our stakeholders, thereby facilitating the safe and effective transportation of hazardous liquids and gases by pipeline. The proposal related to leak survey for Type B gas gathering lines. PHMSA established a new method for determining whether a gas pipeline is an “onshore gathering line” in 2006. PHMSA also imposed new safety standards for “regulated onshore gathering lines,” which divided regulated onshore gathering lines into two risk-based categories. Type A gathering lines are metallic lines with a MAOP of 20 percent or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 psig, in a Class 2, 3, or 4 location. These lines are subject to all of the requirements in Part 192 that apply to transmission lines, except for the regulation that requires the accommodation of in-line inspection tools in the design and construction of certain new and replaced pipelines (49 CFR 192.150) and the integrity management requirements of Part 192, Subpart O. Operators of Type A gathering lines are also permitted to use an alternative process for demonstrating compliance with the requirements of Part 192, Subpart N, Qualification of Pipeline Personnel.

Type B gathering lines includes metallic lines with a MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with a MAOP of 125 psig or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4

location. These lines are subject to less stringent requirements than Type A gathering lines. Specifically, any new or substantially changed Type B line must comply with the design, installation, construction, and initial testing and inspection requirements for transmission lines and, if of metallic construction, the corrosion control requirements for transmission lines. Operators must also include Type B gathering lines in their damage prevention and public education programs, establish the MAOP of those lines under § 192.619, and comply with the requirements for maintaining and installing line markers that apply to transmission lines. It is important that dependable leak detection surveys are used to identify leakage so that appropriate repairs can be initiated to our nation's pipeline system. Prompt repair can help reduce the consequences of incidents to the public, environment and property. Performing field leak surveys is a preventative and proactive safety measure. Operator leak reporting also gives PHMSA valuable information that can be used in trending analysis for the determination of problematic materials or poor operating practices. Over time, unchecked leakage can potentially impact safety in addition to the fact that gas leaks have the risk of accidental ignition causing a fire or explosion.

Prior to the 2006 Final Rule, operators had to perform leak surveys of non-rural gas gathering lines. Also, some Type B gathering lines are located under broad paved areas where electrical surveys (another means of detecting pipe damage) may be difficult to perform and leaking gas could migrate under the pavement and accumulate in surrounding structures. PHMSA believes that leak surveys are an effective means of



ensuring the integrity of low-stress pipelines. Accordingly, PHMSA rejected this alternative.

### 3. Analysis of Environmental Impacts

The Nation's pipelines are located throughout the United States in a variety of diverse environments—from offshore locations, to highly populated urban sites, to unpopulated rural areas. The pipeline infrastructure is a network of over 2.5 million miles of pipeline that move millions of gallons of hazardous liquids and over 55 billion cubic feet of natural gas daily. The biggest source of energy is petroleum, including oil and natural gas. Together, these commodities supply 65 percent of the energy in the United States.

The physical environment potentially affected by the Final Rule includes airspace, water resources (e.g., oceans, streams, lakes), cultural and historical resources (e.g., properties listed on the National Register of Historic Places), biological and ecological resources (e.g., coastal zones, wetlands, plant and animal species and their habitat, forests, grasslands, offshore marine ecosystems) and special ecological resources (e.g., threatened and endangered plant and animal species and their habitat, national and state parklands, biological reserves, wild and scenic rivers) that exist directly adjacent to and within the vicinity of pipelines.

Because the pipelines subject to the Final Rule contain hazardous materials, resources within the physically affected environment, as well as public health and safety,

may be affected by gas pipeline incidents such as spills and leaks. Incidents on pipelines can result in fires and explosions, resulting in damage to the local environment. In addition, since pipelines often contain gas streams laden with condensates and natural gas liquids, failures also result in spills of these liquids, which can cause environmental harm. Depending on the size of a spill or gas leak and the nature of the impact zone, the environmental impacts could vary from property and environmental damage to injuries or, on rare occasions, fatalities.

A majority of the amendments in this Final Rule are not substantive in nature and would have little or no impact on the human environment. It is likely that on a national scale, the cumulative environmental damage from pipelines is reduced, or at a minimum, unchanged. Requiring leakage surveys on Type B gathering lines will have positive environmental impacts. The Environmental Protection Agency (EPA) data indicate that methane contributed to nine percent of the reported greenhouse gas emissions in Calendar Year 2011 ([www.epa.gov/methane/](http://www.epa.gov/methane/)). Operators reported 289 leaks repaired on regulated Type B gathering lines in 2011. It is expected that with formalized leak survey programs in place, emissions will be further reduced, in addition to enhanced safety from leak repairs. Although beneficial, this would not be a large-scale impact on the environment.

For these reasons, PHMSA has concluded that neither of the alternatives discussed above would result in any significant impacts on the environment.

#### 4. Consultations

Various industry associations and state regulatory agencies, such as the American Gas Association, the American Petroleum Associations and NAPSAR, were consulted in the development of this rulemaking.

#### 5. Finding of No Significant Impact

PHMSA has determined that the selected alternative would not have a significant impact on the human environment.

#### Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement published in the Federal Register on April 11, 2000, (70 FR 19477).

#### Executive Order 13132

PHMSA has analyzed this Final Rule according to Executive Order 13132 ("Federalism"). The Final Rule does not have a substantial direct effect on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. This Final Rule does not impose substantial direct compliance costs on state and local governments. This Final Rule does not preempt state law for intrastate pipelines. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

## Executive Order 13211

This Final Rule is not a "significant energy action" under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this Final Rule as a significant energy action.

### **List of Subjects**

#### 49 CFR Part 191

Pipeline Safety, Reporting, and recordkeeping requirements.

#### 49 CFR Part 192

Fire prevention, Incorporation by reference, Pipeline safety, Security measures

#### 49 CFR Part 195

Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, 49 CFR Chapter I is amended as follows:

PART 191 – TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE;  
ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED  
CONDITION REPORTS

1. The authority citation for Part 191 is revised to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 49 CFR 1.97.

2. In § 191.7 paragraphs (a) and (b) are revised and paragraph (e) is added to read as follows:

**§ 191.7 Report submission requirements**

(a) General. Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at <http://portal.phmsa.dot.gov/pipeline> unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.

(b) Exceptions: An operator is not required to submit a safety-related condition report (§191.25) electronically.

\* \* \* \* \*

(e) National Pipeline Mapping System (NPMS). An operator must provide the NPMS data to the address identified in the NPMS Operator Standards manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

3. In § 191.25 paragraph (a) is revised to read as follows:

**§ 191.25 Filing safety-related condition reports**

(a) Each report of a safety-related condition under §191.23(a) must be filed (received by OPS within five working days, not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to [InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov) or by facsimile at (202) 366–7128.

\* \* \* \* \*

**§ 191.27 [Removed]**

4. Section 191.27 is removed.

5. Section 191.29 is added to read as follows:

**§ 191.29 National Pipeline Mapping System**

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

(2) The name of and address for the operator.

(3) The name and contact information of a pipeline company employee, to be displayed on a public website, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

PART 192 –TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE:  
MINIMUM FEDERAL SAFETY STANDARDS

6. The authority citation for Part 192 is revised to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116 and 60118, 60137; and 49 CFR 1.97.

7. In § 192.3, definitions for “Welder” and “Welding operator” are added in alphabetical order to read as follows:

**§ 192.3 Definitions.**

\* \* \* \* \*

Welder means a person who performs manual or semi-automatic welding.

Welding operator means a person who operates machine or automatic welding equipment.

8. In § 192.9, paragraph (d)(7) is added to read as follows:

**§ 192.9 What requirements apply to gathering lines?**

\* \* \* \* \*

(d) \* \* \*

(7) Conduct leakage surveys in accordance with § 192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with § 192.703(c).

\* \* \* \* \*

9. In § 192.65, paragraph (a) is revised to read as follows:

**§ 192.65 Transportation of pipe.**

(a) Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, *see* § 192.7).

\* \* \* \* \*

10. In the table in § 192.112, paragraph (e) is revised to read as follows:

**§ 192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.**

\* \* \* \* \*

To address this design issue:	The pipeline segment must meet these additional requirements:
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* * *	* * * *
(e) Mill hydrostatic test	<p>(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds.</p> <p>(2) Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.</p> <p>(3) Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by “ANSI/API Spec 5L” (incorporated by reference, <i>see</i> § 192.7).</p>
* * *	* * * *

11. In § 192.153, a new paragraph (e) is added to read as follows:

**§ 192.153 Components fabricated by welding.**

\* \* \* \* \*

(e) A component having a design pressure established in accordance with paragraph (a) or paragraph (b) of this section and subject to the strength testing requirements of § 192.505(b) must be tested to at least 1.5 times the MAOP.

12. In §192.165, paragraph (b)(3) is revised to read as follows:

**§ 192.165 Compressor stations: Liquid removal.**

\* \* \* \* \*

(b) \* \* \*

(3) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference , *see* § 192.7) and the additional requirements of § 192.153(e) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

13. In § 192.225, paragraph (a) is revised to read as follows:

**§ 192.225 Welding procedures.**

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7) or section IX ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* § 192.7), to produce welds which meet the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the referenced welding standard(s).

\* \* \* \* \*

14. Section 192.227 is revised to read as follows:

**§ 192.227 Qualification of welders and welding operators.**

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* § 192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in § 192.7 may weld but may not re-qualify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

15. Section 192.229 is revised to read as follows:

**§ 192.229 Limitations on welders and welding operators.**

(a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process.

(c) A welder or welding operator qualified under § 192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7½ months. A welder or welding operator qualified under an earlier edition of a standard listed in § 192.7 of this part may weld, but may not re-qualify under that earlier edition; and,

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or re-qualifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder or welding operator qualified under § 192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under § 192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder or welding operator has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

16. In § 192.241, paragraph (c) is revised to read as follows:

**§ 192.241 Inspection and test of welds.**

\* \* \* \* \*

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, *see* §192.7). Appendix A of API Std 1104 may not be used to accept cracks.

17. In § 192.243, paragraph (e) is revised to read as follows:

**§ 192.243 Nondestructive testing.**

\* \* \* \* \*

(e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

\* \* \* \* \*

18. In § 192.285, paragraph (c) is revised to read as follows:

**§ 192.285 Plastic pipe: Qualifying persons to make joints.**

\* \* \* \* \*

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under § 192.513.

\* \* \* \* \*

19. Section 192.305 is revised to read as follows:

**§ 192.305 Inspection: General.**

Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

20. In § 192.503, a new paragraph (e) is added to read as follows:

**§ 192.503 General requirements.**

\* \* \* \* \*

(e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in § 192.143.

**§ 192.505 [Amended]**

21. In § 192.505, paragraph (d) is removed and paragraph (e) is redesignated as paragraph (d).

22. In § 192.620, paragraph (c)(1) and the first sentence of paragraph (c)(8) are revised to read as follows:

**§ 192.620 Alternative maximum operating pressure for certain steel pipelines.**

\* \* \* \* \*

(c) \* \* \*

(1) For pipelines already in service, notify the PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify the state pipeline safety authority

when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.

\* \* \* \* \*

(8) A Class 1 and Class 2 location can be upgraded one class due to class changes per § 192.611(a).

\* \* \* \* \*

23. In § 192.805 paragraph (i) is revised to read as follows:

**§ 192.805 Qualification program.**

\* \* \* \* \*

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to [InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov), or by mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2<sup>nd</sup> Floor, E22-321, New Jersey Avenue, S.E. Washington, DC 20590.

24. In § 192.925, the introductory text of paragraph (b) and the introductory text of paragraph (b)(2) are revised to read as follows:

**§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**

\* \* \* \* \*



(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage and to address the threat as required by §192.917(e)(1).

\* \* \* \* \*

(2) *Indirect inspection.* In addition to the requirements in ASME/ANSI B31.8S, section 6.4 and in NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include—

\* \* \* \* \*

25. Section 192.949 is revised to read as follows:

**§ 192.949 How does an operator notify PHMSA?**

An operator must provide any notification required by this subpart by—

(a) Sending the notification by electronic mail to

[InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov); or

(b) Sending the notification by mail to ATTN: Information Resources Manager,

DOT/PHMSA/OPS, East Building, 2<sup>nd</sup> Floor, E22-321, 1200 New Jersey Ave,  
SE, Washington, DC 20590.

PART 195 – TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

26. The authority citation for Part 195 is revised to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60116, 60118, 60132, 60137,  
and 49 CFR 1.97.

27. In § 195.2, the definitions of “alarm” and “hazardous liquid” are revised and definitions for “welder” and “welder operator” are added in appropriate alphabetical order to read as follows:

**§ 195.2 Definitions.**

\* \* \* \* \*

*Alarm* means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

\* \* \* \* \*

*Hazardous liquid* means petroleum, petroleum products, anhydrous ammonia, or ethanol.

\* \* \* \* \*

*Welder* means a person who performs manual or semi-automatic welding.

*Welding operator* means a person who operates machine or automatic welding equipment.

28. In § 195.56 paragraph (a) is revised to read as follows:

**§ 195.56 Filing safety-related condition reports.**

(a) Each report of a safety-related condition under § 195.55(a) must be filed (received by OPS) within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to [InformationResourcesManager@dot.gov](mailto:InformationResourcesManager@dot.gov), or by facsimile at (202) 366-7128.

\* \* \* \* \*

**§ 195.57 [Removed]**

29. Section 195.57 is removed.

30. In § 195.58, paragraphs (a) and (b) are revised and a new paragraph (e) is added to read as follows:

**§ 195.58 Report submission requirements.**

(a) General. Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to PHMSA at <http://opsweb.phmsa.dot.gov> unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.

(b) Exceptions: An operator is not required to submit a safety-related condition report (§ 195.56) electronically.

\* \* \* \* \*

(e) National Pipeline Mapping System (NPMS). An operator must provide NPMS data to the address identified in the NPMS Operator Standards Manual available

at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

31. Section 195.61 is added to read as follows:

**§ 195.61 National Pipeline Mapping System.**

(a) Each operator of a hazardous liquid pipeline facility must provide the following geospatial data to PHMSA for that facility:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

(2) The name of and address for the operator.

(3) The name and contact information of a pipeline company employee, to be displayed on a public website, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) This information must be submitted each year, on or before June 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must refer to the information provided in the NPMS Operator Standards manual available at [www.npms.phmsa.dot.gov](http://www.npms.phmsa.dot.gov) or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

**§ 195.64 [Removed]**

32. In § 195.64, paragraph (c)(1)(iii) is removed.

33. Section 195.204 is revised to read as follows:

**§ 195.204 Inspection – general.**

Inspection must be provided to ensure that the installation of pipe or pipeline systems is in accordance with the requirements of this subpart. Any operator personnel used to perform the inspection must be trained and qualified in the phase of construction to be inspected. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

34. In § 195.214, paragraph (a) is revised to read as follows:

**§ 195.214 Welding procedures.**

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* §195.3), or section IX of ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* §195.3). The quality of the test welds used to qualify welding procedures must be determined by destructive testing.

\* \* \* \* \*

35. In § 195.222 the heading, paragraph (a), the introductory text of paragraph (b), and paragraph (b)(2) are revised to read as follows:

**§ 195.222 Welders and welding operators: Qualification of welders and welding operators.**

(a) Each welder or welding operator must be qualified in accordance with section 6, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* § 195.3), or section IX of ASME Boiler and Pressure Vessel Code (BPVC), (incorporated by reference, *see* § 195.3), except that a welder or welding operator qualified under an earlier edition than an edition listed in § 195.3, may weld but may not re-qualify under that earlier edition.

(b) No welder or welding operator may weld with a welding process unless, within the preceding 6 calendar months, the welder or welding operator has—

\* \* \* \* \*

(2) Had one weld tested and found acceptable under section 9 or Appendix A of API Std 1104 (incorporated by reference, *see* § 195.3).

36. In § 195.228, paragraph (b) is revised to read as follows:

**§ 195.228 Welds and welding inspection: Standards of acceptability.**

\* \* \* \* \*

(b) The acceptability of a weld is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, *see* § 195.3). Appendix A of API Std 1104 may not be used to accept cracks.

37. In § 195.234, paragraph (d) is revised to read as follows:

**§ 195.234 Welds: Nondestructive testing.**

\* \* \* \* \*

(d) During construction, at least 10 percent of the girth welds made by each welder and welding operator during each welding day must be nondestructively tested over the entire circumference of the weld.

\* \* \* \* \*

38. In § 195.307 paragraphs (c) and (d) are revised to read as follows:

**§ 195.307 Pressure testing aboveground breakout tanks.**

\* \* \* \* \*

(c) For aboveground breakout tanks built to API Std 650 (incorporated by reference, *see* § 195.3) and first placed in service after October 2, 2000, testing must be in accordance with sections 7.3.5 and 7.3.6 of API Standard 650 (incorporated by reference, *see* § 195.3).

(d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated tanks built to API Std 650 or its predecessor Standard 12 C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 12.3 of API Standard 653 (incorporated by reference, *see* § 195.3).

\* \* \* \* \*

39. In § 195.428, paragraph (c) is revised to read as follows:

**§ 195.428 Overpressure safety devices and overfill protection systems.**

\* \* \* \* \*

(c) Aboveground breakout tanks that are constructed or significantly altered according to API Std 2510 (incorporated by reference, *see* § 195.3) after October 2, 2000, must have an overfill protection system installed according to API Std 2510, section 7.1.2. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API RP 2350 (incorporated by reference, *see* § 195.3). However, an operator need not comply with any part of API RP 2350 for a particular breakout tank if the operator describes in the manual required by § 195.402 why compliance with that part is not necessary for safety of the tank.

\* \* \* \* \*

40. In § 195.452, paragraph (h)(4)(i) introductory text and paragraph (m) are revised to read as follows:

**§ 195.452 Pipeline integrity management in high consequence areas.**

\* \* \* \* \*

(h) \* \* \*

(4) \* \* \*

(i) *Immediate repair conditions.* An operator’s evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the



temporary reduction in operating pressure using the formulas referenced in paragraph (h)(4)(i)(B) of this section. If no suitable remaining strength calculation method can be identified, an operator must implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two months prior to the date of inspection, until the anomaly is repaired. An operator must treat the following conditions as immediate repair conditions:

\* \* \* \*

(m) How does an operator notify PHMSA? An operator must provide any notification required by this section by:

(1) Sending the notification by electronic mail to

InformationResourcesManager@dot.gov; or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2<sup>nd</sup> Floor, E22-321, 1200 New Jersey Ave, SE, Washington, DC 20590.

41. In § 195.505 paragraph (i) is revised to read as follows:

**§ 195.505 Qualification program.**

\* \* \* \*

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to

InformationResourcesManager@dot.gov, or by mail to ATTN: Information Resources

Manager DOT/PHMSA/OPS, East Building, 2<sup>nd</sup> Floor, E22-321, New Jersey Avenue,  
S.E. Washington, DC 20590.

42. Section 195.571 is revised to read as follows:

**§195.571 What criteria must I use to determine the adequacy of cathodic protection?**

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained paragraphs 6.2.2, 6.2.3, 6.2.4, 6.2.5 and 6.3 in NACE SP 0169 (incorporated by reference, *see* § 195.3).

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Timothy P. Butters,  
Acting Administrator

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