DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 190, 191, 192, 195, and 199

[Docket No. PHMSA–2013–0163; Amdt. Nos. 190–19; 191–25; 192–123; 195–101; 199–27]

RIN 2137–AE94

Pipeline Safety: Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes

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

ACTION: Final rule.

SUMMARY: PHMSA is amending the pipeline safety regulations to address requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act), and to update and clarify certain regulatory requirements. Among other provisions, PHMSA is adding a specific time frame for telephonic or electronic notifications of accidents and incidents and adding provisions for cost recovery for design reviews of certain new projects, for the renewal of expiring special permits, and setting out the process for requesting protection of confidential commercial information. PHMSA is also amending the drug and alcohol testing requirements, and incorporating consensus standards by reference for in-line inspection (ILI) and Stress Corrosion Cracking Direct Assessment (SCCDA).

DATES: This final rule is effective March 24, 2017. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of March 24, 2017.

ADDRESSES: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Ave. SE., Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Tewabe Asebe by telephone at 202–366–5523, by email at *Tewabe.Asebe@dot.gov,* or by mail at U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Ave. SE., Washington, DC 20590.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Executive Summary

A. Purpose of the Regulatory Action and Summary of the Major Provisions of the Regulatory Action in Question

The purpose of this rulemaking action is to strengthen the Federal pipeline safety regulations and to address sections 9 and 13 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act). Public Law 112–90. The amendment associated with section 9 of the 2011 Act limits the timeframe within which the operator must electronically or telephonically report notice of an accident or incident to within one hour of confirmed discovery of the event. PHMSA expects that quicker accident and incident reporting will lead to a safety benefit to the public, the environment, and limit property damage. The amendment associated with section 13 of the 2011 Act allows PHMSA to recover its costs for design review work PHMSA conducts on behalf of the operators, which will allow PHMSA to use its limited resources in protecting public safety. PHMSA is also providing a renewal procedure for expiring special permits, and is making other minor and administrative changes. This final rule does not include the Operator Qualification (OQ) requirements proposed under subpart N for natural gas pipelines and subpart G for hazardous liquid pipelines; however, PHMSA is proceeding with amendments to control room staff training requirements. PHMSA is delaying final action on the OQ proposals until a later date and fully expects to consider all the comments received and the recommendations of the Pipeline Advisory Committees related to those specific issues in a subsequent final rule published in the near future.

The specific amendments codified by this final rule are listed in detail below:

- Specifying an operator's accident and incident reporting time to not later than one hour after confirmed discovery and requiring revision or confirmation of initial notification within 48 hours of the confirmed discovery of the accident or incident;
- Setting up a cost recovery fee structure for design review of new gas and hazardous liquid pipelines with either overall design and construction costs totaling at least $2,500,000,000 or that contain new and novel technologies;
- Addressing the National Transportation Safety Board's (NTSB) recommendation to clarify training requirements for control room personnel;
- Providing a renewal procedure for expiring special permits;
- Excluding farm taps from the requirements of the Distribution Integrity Management Program (DIMP) requirements while proposing safety requirements for the farm taps;
- Requiring pipeline operators to report to PHMSA a change in product (*e.g.,* from liquid to gas, from crude oil to highly volatile liquids (HVL)) or a permanent reversal of flow that lasts more than 30 days;
- Providing methods for assessment tool selection by incorporating consensus standards by reference in part 195 for stress corrosion cracking direct assessment (SCCDA) that were not developed when the Integrity Management (IM) regulations were issued;
- Requiring electronic reporting of drug and alcohol testing results in part 199;
- Modifying the criteria used to make decisions about conducting post-accident drug and alcohol tests and requiring operators to keep for at least 3 years a record of the reason why post-accident drug and alcohol tests were not conducted;
- Including the procedure to request protection for confidential commercial information submitted to PHMSA;
- Adding reference to appendix B of API 1104 related to in-service welding in parts 192 and 195; and

• Amending minor editorial corrections.

B. Costs and Benefits

PHMSA has estimated annual compliance costs at $0.6 million less savings to be realized from the removal of farm taps from the Distribution Integrity Management Program requirements. PHMSA could not quantify annual benefits as readily due to data limitations. However, the improvements to and the clarification of regulations, including those for post-incident investigations along with other provisions, are designed to reduce pipeline incidents and the associated consequences, including the potential to prevent a future high-consequence event, such as those that have occurred on gas transmission and hazardous liquid pipelines in the past.

II. Background

A. Notice of Proposed Rulemaking

On July 10, 2015, PHMSA published a notice of proposed rulemaking (NPRM) to address requirements in the 2011 Act pertaining to accident and incident reporting (section 9) and cost recovery (section 13); to address certain National Transportation Safety Board (NTSB) recommendations made in response to the pipeline incidents in San Bruno CA,[1] and Marshall, MI;[2] and to update and clarify certain regulatory requirements. 80 FR 39916. Among other provisions, PHMSA proposed to add a specific time frame for telephonic or electronic notifications of accidents and incidents and to add provisions for cost recovery for design reviews of certain new projects, to add provisions for the renewal of expiring special permits, and to include the procedure for submitters of information to request PHMSA treat the information as confidential. Also, PHMSA proposed changes to the operator qualification (OQ) requirements and drug and alcohol testing requirements and proposed to incorporate consensus standards by reference for inline inspection (ILI) and Stress Corrosion Cracking Direct Assessment (SCCDA).

B. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the National Transportation Safety Board Recommendations

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law by President Barack Obama on January 3, 2012. The 2011 Act was enacted in part to enhance safety and protect the environment during the transportation of products by pipeline. H. Rept. 112–297. As discussed above, this rulemaking addresses two provisions from the 2011 Act:

• Section 9 requires PHMSA to specify a time limit for telephonic or electronic reporting of pipeline accidents and incidents

• Section 13, which is codified at 49 U.S.C. 60117(n), allows PHMSA to prescribe a fee structure and assessment methodology to recover costs associated with design and construction reviews

This rule also addresses certain National Transportation Safety Board (NTSB) recommendations arising out of the September 9, 2010, San Bruno, CA, pipeline rupture of a natural gas line that killed eight people, and the July 25, 2010, pipeline rupture in Marshall, MI, that resulted in the release of an estimated 843,444 gallons of crude oil in a wetland. The specific NTSB recommendations addressed in this rulemaking action are:

- P–11–12 on drug and alcohol testing of employees whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident
- P–12–3 on assessment tools incorporation by reference in part 195
- P–12–7 on team training of control center staff
- P–12–8 on extending operator qualification training requirements for all hazardous liquid and gas transmission control center staff involved in pipeline operational decisions

C. Summary of Each Topic Under Consideration

Accident and Incident Notification

Section 9 of the 2011 Act directs PHMSA to require pipeline operators to provide notification at the earliest practicable moment following confirmed discovery of an accident or incident, not to exceed 1 hour following the time of such confirmed discovery. PHMSA is amending the Federal pipeline safety regulations to require operators to provide telephonic or electronic notification of an accident or incident at the earliest practicable moment, including the amount of product loss, following confirmed discovery.

Cost Recovery for Design Reviews

On cost recovery for design reviews, section 13 of the 2011 Act allows PHMSA to prescribe a fee structure and assessment methodology to recover costs associated with any project with design review and construction costs totaling at least $2,500,000,000 and for new or novel technologies or design, as determined by the Secretary. PHMSA is amending the Federal pipeline safety regulations to prescribe a fee structure and assessment methodology for recovering costs associated with design reviews of new gas and hazardous liquid pipelines with either overall design and construction costs totaling at least $2,500,000,000 or that contain new and novel technologies.

NTSB Recommendations on Control Room Center Staff

PHMSA is addressing the NTSB recommendation to extend operator qualification requirements to control center staff involved in pipeline operational decisions (P–12–8) and to require team training for control center staff involved in pipeline operations similar to those used in other transportation modes (P–12–7).

Special Permit Renewal

On special permit renewal, PHMSA is amending § 190.341 of the Federal pipeline safety regulations to add procedures for renewing a special permit.

Farm Taps

On farm taps, PHMSA is amending the Federal pipeline safety regulations in 49 CFR part 192 to add a new section, § 192.740, to cover regulators and overpressure protection equipment for an individual service line that originates from a transmission, gathering, or production pipeline (*i.e.,* a farm tap), and to revise § 192.1003 to exclude farm taps from the requirements of the Distribution Integrity Management Program (DIMP).

Reversal of Flow or Change in Product

On reversal of flow or change in product, PHMSA is expanding the list of events in §§ 191.22 and 195.64 that require electronic notification to include the reversal of flow of product or change in product in a mainline pipeline. PHMSA is requiring operators to notify PHMSA electronically no later than 60 days before there is a reversal of the flow of product through a pipeline or when there is a change in the product flowing through a pipeline. In addition, PHMSA is amending §§ 192.14 and 195.5 to reflect the 60-day notification and to require operators to notify PHMSA when over 10 miles of pipeline is replaced.

[1] *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.*

[2] *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf.*

Pipeline Assessment Tools

On pipeline assessment tools, PHMSA is incorporating by reference the following consensus standards into 49 CFR part 195: API STD 1163, ''In-Line Inspection Systems Qualification'' (April 2013); NACE SP0102–2010 ''Standard Practice, Inline Inspection of Pipelines'' (revised March 13, 2010); NACE SP0204–2008 ''Standard Practice, Stress Corrosion Cracking (SCC) Direct Assessment Methodology'' (reaffirmed September 18, 2008); and ANSI/ASNT ILI–PQ–2005, ''In-line Inspection Personnel Qualification and Certification'' (reapproved October 11, 2010). Also, PHMSA is allowing pipeline operators to conduct assessments using tethered or remote control tools not explicitly discussed in NACE SP0102–2010, provided the operators comply with applicable sections of NACE SP0102–2010.

Incorporation of these consensus standards will assure better consistency, accuracy and quality in pipeline assessments conducted using ILI and SCCDA.

Standards for ILI

When the part 195 IM requirements were issued, there were no consensus industry standards that addressed ILI. Since then the following standards have been published:

1. In 2002, NACE International published the first consensus industry standard that specifically addressed ILI (NACE Recommended Practice RP0102, ''Inline Inspection of Pipelines''). NACE International revised this document in 2010 and republished it as a Standard Practice, SP0102. PHMSA expects that the consistency, accuracy, and quality of pipeline ILI will be improved by incorporating the NACE International 2010 standard into the regulations. PHMSA asked the Standards Developing Organizations to develop this and the other standards and PHMSA is now adopting them to bring consistency throughout the industry. These standards provide tables to improve tool selection. PHMSA is providing hazardous liquids pipeline operators choices of tools to assess their pipelines and; therefore, PHMSA does not believe that these tool selections incur additional costs to the pipeline operators. The NACE International standard applies to ''free swimming'' inspection tools that are carried down the pipeline by the transported fluid. It does not apply to tethered or remotely controlled ILI tools. While the usage of tethered or remotely controlled ILI tools is less prevalent than the usage of free swimming tools, some pipeline IM assessments have been conducted using these tools. PHMSA believes many of the provisions in the NACE International standard can be applied to tethered or remotely controlled ILI tools and; therefore, PHMSA is allowing the use of these tools provided they generally comply with applicable sections of the NACE standard. The NACE standards were reviewed by PHMSA experts, and they agree with the provisions in the standards. Many operators are already following those guidelines. Our inspection guides will provide further instructions when this final rule is implemented.

2. In 2005, the ASNT published ANSI/ASNT ILI–PQ, ''In-line Inspection Personnel Qualification and Certification.'' The ASNT standard provides for qualification and certification requirements that are not addressed in part 195. In 2010 ASNT published ANSI/ASNT ILI–PQ with editorial changes. The incorporation of this standard into the Federal pipeline safety regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry. This and the other standards are being used by many operators but not all. This rule will ensure that all operators use these standards. Overall cost will not change, because these consensus standards will help operators eliminate problems before they arise. SCCDA is a technique allowed for gas transmission pipelines but is not specifically addressed in § 195.452 although it is also applicable to hazardous liquid pipelines. This rulemaking action will allow HL operators to use the SCCDA technique and ASNT is one of them. The ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

- Requirements for written procedures.
- Personnel qualification levels.
- Education, training, and experience requirements.
- Training programs.
- Examinations (testing of personnel).
- Personnel certification and recertification.
- Personnel technical performance evaluations.

3. In 2005, API published API STD 1163, ''In-Line Inspection Systems Qualification Standard.'' PHMSA proposed to incorporate the 2005 API 1163 because at the time the notice of the rulemaking action was developed, the latest version of API 1163 was under development. PHMSA has evaluated the revisions made to the latest version of API 1163 and determined that the changes are not significant. Therefore, PHMSA is adopting API STD 2013 into part 195.

This Standard serves as an umbrella document that is to be used with and complements the NACE International and ASNT standards that are incorporated by reference in API STD 1163. The API standard is more comprehensive than the requirements currently in part 195. The incorporation of this standard into the Federal pipeline safety regulations will promote a higher level of safety by establishing a consistent methodology to qualify the equipment, people, processes, and software utilized by the ILI industry. The API standard addresses, in detail, each of the following aspects of ILI inspections:

- Systems qualification process.
- Personnel qualification.
- ILI system selection.
- Qualification of performance specifications.
- System operational validation.
- System results qualification.
- Reporting requirements.
- Quality management system.

Stress Corrosion Cracking (SCC) Direct Assessment

4. NACE SP0204–2008 ''Stress Corrosion Cracking Direct Assessment.'' SCC is a degradation mechanism in which steel pipe develops closely spaced tight cracks through the combined action of corrosion and tensile stress (circumferential, residual, or applied). These cracks can grow or coalesce to affect the integrity of the pipeline. SCC is one of several threats that can impact pipeline integrity. IM regulations in part 195 require that pipeline operators assess covered pipe segments periodically to detect degradation from threats that their analyses have indicated could affect the segment. Not all covered segments are subject to an SCC threat, but for those that are, SCCDA is an assessment technique that can be used to address this threat.

Part 195 presently includes no requirements applicable to the use of SCCDA. Experience has shown that pipelines can go through SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE Standard Practice SP0204–2008 addresses near-neutral SCC. In addition, the NACE International recommended practice provides technical guidelines and process requirements that are both more comprehensive and rigorous for conducting SCCDA than are provided by § 192.929 or ASME/ANSI B31.8S.

The NACE standard provides additional guidance as follows:

- The factors that are important in the formation of SCC on a pipeline and what data should be collected;
- Additional factors, such as existing corrosion, which could cause SCC to form;
- Comprehensive data collection guidelines, including the relative importance of each type of data;
- Requirements to conduct close interval surveys of cathodic protection or other aboveground surveys to supplement the data collected during pre-assessment;
- Ranking factors to consider for selecting excavation locations for both near-neutral and high pH SCC;
- Requirements on conducting direct examinations, including procedures for collecting environmental data, preparing the pipe surface for examination, and conducting Magnetic Particle Inspection (MPI) examinations of the pipe; and
- Post assessment analysis of results to determine SCCDA effectiveness and assure continual improvement.

In general, NACE SP0204–2008 provides thorough and comprehensive guidelines for conducting SCCDA and is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S. PHMSA believes that requiring the use of NACE SP0204–2008 will enhance the quality and consistency of SCCDA conducted under IM requirements.

SCC has also been the subject of research and development (R&D) programs that have been funded in whole or in part by PHMSA in recent years. PHMSA reviewed the results of several R&D programs concerning SCC as part of its consideration of whether it was appropriate to incorporate the NACE standard into the regulations. Among the reports PHMSA reviewed was ''Development of Guidelines for Identification of SCC Sites and Estimation of Re-inspection Intervals for SCC Direct Assessment,'' published by Integrity Corrosion Consulting Ltd. in May 2010.[3] This report evaluated the results of numerous studies conducted since the 1960s regarding SCC. The report used the conclusions from the studies to identify a group of 109 guidelines that pipeline operators could use to help identify sites where SCC might occur and determine appropriate re-inspection intervals when SCC is found. The guidelines address both high-pH and near-neutral-pH conditions. This report noted that the information used in developing the NACE standard consisted primarily of empirical data gathered from operators examining pipeline field conditions and failures. In contrast, the studies examined by Integrity Corrosion Consulting were mechanistic studies, and their results serve to complement the information operators have gained through field experience. PHMSA's review of the guidelines in this report identified a number of areas not addressed in detail in the NACE standard. Accordingly, PHMSA has included additional factors in § 195.588 that an operator must consider if the operator uses direct assessment to assess SCC.

PHMSA acknowledges that the NACE standard may not address all aspects of SCC management, but PHMSA considers it better to incorporate additional structured guidance that is available now rather than await future standards. There is continual improvement in technology to detect and address various SCC threats. Three different standards organizations are currently working to improve standards on SCC: ASME B31.8, NACE 204 and API 1160. PHMSA participates on these technical committees. As more knowledge is gained on other types of SCC, such as sulfide assisted SCC and when newer standards get published, PHMSA will consider adopting them.

PHMSA is revising § 195.588, which specifies requirements for the use of external corrosion direct assessment on hazardous liquid pipelines, to include reference to NACE SP0204–2008 for the conduct of SCCDA. The rule will not require that SCCDA assessments be conducted, but it will require that the NACE standard be followed if an operator elects to perform such assessments. PHMSA has included additional factors that an operator must consider to address these if the operator uses direct pipeline to assess SCC.

Post-Accident Drug and Alcohol Testing

On electronic reporting of drug and alcohol testing results, PHMSA is requiring operators electronic reporting for anti-drug testing results required in § 199.119 and alcohol testing results required in § 199.229. PHMSA is modifying these regulations to specify that it will provide notice to operators in the PHMSA Portal.[4]

On post-accident drug and alcohol testing, PHMSA is modifying §§ 199.105 and 199.225 by requiring drug testing of employees after an accident and to allow exemption from drug testing only when there is sufficient information that establishes the employee(s) had no role in the accident. Therefore, PHMSA is amending the post-accident drug testing regulation to require documentation of the decision and to keep the documentation for at least three years.

Information Made Available to the Public and Request for Protection of Confidential Commercial Information

On information made available to the public and request for confidential treatment, PHMSA is including the procedure for requesting confidential treatment of confidential commercial information submitted to PHMSA.

In-Service Welding

On in-service welding, PHMSA is revising §§ 192.225, 192.227, 195.214, and 195.222 to add reference to API 1104, Appendix B.

III. Advisory Committees Meeting

On June 2, 2016, the Gas Pipeline Advisory Committee (GPAC)[5] and the Liquid Pipeline Advisory Committee (LPAC)[6] met jointly in Arlington, Virginia. The committees are statutorily mandated advisory committees that advise PHMSA on proposed gas pipeline or hazardous liquid pipeline safety standards and risk management principles. Both committees were established in accordance with the Federal Advisory Committee Act, 5 U.S.C. App., as amended, and 49 U.S.C. 60115. Each committee consists of 15 members, with membership evenly divided among the Federal and state governments, regulated industry, and general public. The committees advise PHMSA on the technical feasibility, reasonableness, practicability, and cost-effectiveness of each proposed pipeline safety standard.

During the meeting, the committees considered the NPRM that was proposed to: Address (1) section 9 of the 2011 Act that would require operators to electronically or telephonically report notice of an accident and incident not later than one hour after the confirmed discovery; (2) address section 13 of the 2011 Act that would allow PHMSA to recover its costs for design review work PHMSA would conduct on behalf of the operators, which would allow PHMSA to use its limited resources in protecting the public safety; (3) expand the existing Operator Qualification (OQ) scope to cover new construction and certain other currently uncovered tasks; (4) provide a renewal procedure for expiring special permits; (5) exclude

[3] *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=199.*

[4] *https://portal.phmsa.dot.gov/.*

[5] Officially designated as the Technical Pipeline Safety Standards Committee.

[6] Officially designated as the Technical Hazardous Liquid Pipeline Safety Standards Committee.

farm taps from the DIMP requirements and to amend part 192 to add a new section that prescribes inspection activities for pressure regulators and over-pressurization protection equipment on service lines that originate from transmission, gathering, or production pipelines; (6) incorporate by reference into 49 CFR part 195: API STD 1163, ''In-Line Inspection Systems Qualification Standard'' (August 2005); NACE Standard Practice SP0102–2010 ''Inline Inspection of Pipelines'' NACE SP0204–2008 ''Stress Corrosion Cracking Direct Assessment;'' and ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification'' (2010); (7) modify §§ 199.105 and 199.225 by requiring drug testing of employees after an accident and allowing exemption from drug testing only when there is sufficient information that establishes the employee(s) had no role in the accident, and requiring documentation of the decision not to perform drug testing and to keep the documentation for at least three years; (8) and include the procedure for requesting confidential treatment of information submitted to PHMSA and PHMSA's decision regarding the request.

After discussion, both Committees separately voted unanimously to recommend PHMSA implement the NPRM with certain changes. Specifically, the Committees recommended as follows:

A. Accident and Incident Notification Reporting

Some of the Gas Pipeline Advisory Committee members were concerned about the accuracy of reporting gas leak within one hour of confirmed discovery of the leak. After discussion the issue, the committee agreed to recommend removing the one-hour amount of product lost reporting requirement from where it was proposed in § 191.5(b)(5) and moving the requirement to § 191.5(c).

Also, both committees discussed the definition for ''confirmed discovery'' and separately recommended revising the definition as follows:

Confirmed Discovery: when it can be reasonably determined, based on information available to the operator at the time, that a reportable event has occurred, even if only based on a preliminary evaluation.

Responses to the Advisory Committees' Recommendations

The committees' recommendation also addresses the public comments and, therefore, PHMSA accepts the recommended changes.

B. Cost Recovery of Design Review

Both committees discussed the proposal and agreed to recommend revising the definition for ''new and novel technologies,'' as follows:

New and novel technologies means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into Parts 192, 193, and 195 are not ''new or novel technologies.''

Responses to the Advisory Committees' Recommendations

The committees' recommendation also addresses the public comments and, therefore, PHMSA accepts the recommended changes.

Also, both committees recommended revising the proposed § 190.405 by removing the phrases ''permitting activities, purchasing, and right of way acquisition.'' This recommendation also addresses the public comments and, therefore, PHMSA accepts the recommended changes.

C. Operator Qualification Requirements

During the meeting, the committees discussed provisions related to the operator qualification requirements proposed in the NPRM. PHMSA is delaying final action on the OQ proposals under subpart N for natural gas pipelines and subpart G for hazardous liquid pipelines until a later date and fully expects to consider all the comments received and the recommendations of the Pipeline Advisory Committees related to those specific issues in a subsequent final rule.

D. Special Permit Renewal

Both committees recommended revising § 190.341(d)(1) by replacing the word ''application'' with the phrase ''application or renewal,'' revising § 190.341(f) to limit aerial photography of pipeline segments where special permits affect public safety such as a class location special permit that allows a less stringent design factor in a populated area and allow operators to submit a summary of inline inspection survey results with permit renewals, and revising § 190.341(e) to clarify that special permit renewals must be submitted 180 days prior to the grant expiration.

Responses to the Advisory Committees' Recommendations

These committees' recommendations also address the public comments and, therefore, PHMSA accepts the recommended changes.

E. Farm Tap

The Gas Pipeline Technical Committee recommended revising § 192.740 to make the following changes: In (a) change ''originates from'' to ''directly connected to,'' and in (b) to add the phrase ''(except rupture discs) after the phrase ''relief device.''

Also, the Committee recommended revising § 192.1003(b) to make the following change: Replace the phrase ''. . . a service line that originates directly from a transmission'' with ''. . . an individual service line directly connected to a transmission.''

Responses to the Advisory Committee's Recommendations

The committee's recommendations also address the public comments and, therefore, PHMSA accepts the recommended changes.

F. Pipeline Assessment Tools

The Liquid Pipeline Advisory Committee recommended adopting the section as published in the NPRM except with the latest API STD 1163, ''In-Line Inspection Systems Qualification Standard'' (April 2013) version.

Also, a member of the advisory committee asked whether an operator has the option to run the right tools in assessing for in-line inspection and stress corrosion cracking direct assessment.

Responses to the Advisory Committee's Recommendations

The committee's recommendations also address the public comments and, therefore, PHMSA accepts the recommended changes.

With regard to the comment on right tool selection, the very reason PHMSA is incorporating these consensus industry standards into the Federal pipeline safety regulations is to guide operators to use the right tools. Operators can select the right pipeline assessment tools from the incorporated industry standards. However, if operators decide to choose assessment tools that are not incorporated by reference, the operators must justify, with data, why the selected assessment tools are better suited for their pipelines than the incorporated industry standards. In selecting assessment tools, operators should analyze the goal and objectives of the inspection and match relevant facts known about the pipeline and expected anomalies with the capabilities and performance of an assessment tool. The selected assessment tool should have accuracy and detection capabilities, detection sensitivity, and classification capability. In addition, the sizing accuracy should be sufficient enough to enable prioritization, the location accuracy should enable locating anomalies, and the requirements for defect assessment must be adequate for the expected defect assessment algorithm.

G. On Post-Accident Drug and Alcohol Testing

Both committees recommended removing existing language at the end of § 199.105(b)(1) that states ''. . .or because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use.''

In addition, some advisory committee members requested for compliance period to address union agreement for the drug testing reporting.

Responses to the Advisory Committee's Recommendations

The committees' recommendations address the public comments. PHMSA accepts the recommended deletion for § 199.105(b). PHMSA is not requiring new recordkeeping in this rule. The only requirement is to keep records of decisions not to administer post-accident employee drug tests for at least 3 years.

H. Information Made Available to the Public and Request for Confidential Treatment

Both committees recommended to make editorial changes, including the title of the section, to reflect the agency's goal in providing a procedure for confidential commercial information submitted to PHMSA.

Responses to the Advisory Committees' Recommendations

The committees' recommendations also address the public comments and, therefore, PHMSA accepts the recommended changes.

IV. Summary and Response to Comments

PHMSA received 35 comments on the proposed rule from the National Transportation Safety Board, Pipeline Safety Trust, pipeline trade associations, the Distribution Contractors Association, the ASME B31Q Qualification of Pipeline Personnel Technical Committee, the American Medical Review Officers and the Pipeline Testing Consortium, pipeline operators, pipeline safety consultants, and citizens.

General Comments

Most of the pipeline operators' comments were in support of and similar to their trade associations; therefore, pipeline operators' comments similar to their associations are not summarized again in the specific comments. However, comments that were not addressed by the trade associations are summarized.

A. Accident and Incident Notification

1. PHMSA's Proposal

PHMSA proposed to amend the Federal pipeline safety regulations to require operators to provide telephonic or electronic notification of an accident or incident at the earliest practicable moment, including the amount of product loss, following confirmed discovery. PHMSA proposed to define ''confirmed discovery'' as: *Confirmed discovery* means there is sufficient information to determine that a reportable event may have occurred even if an evaluation has not been completed.

2. Summary of Public Comment

Definitions (§§ 191.3 and 195.2)

PHMSA received comments from trade organizations, safety groups, government entities, and others stating the proposed definition for ''confirmed discovery'' is confusing because it suggests that the operator has sufficient ''confirmed'' information that an event has occurred but also contains the phrase ''may have occurred.'' They believe ''sufficient confirmed information'' is an indication that a reportable or actual event has occurred, and the confirmed information should provide enough evidence of that event. Therefore, they urged PHMSA to revise the definition to remove ''may have'' and read ''. . . a reportable event has occurred.''

Paiute Pipeline Company and Southwest Gas Corporation proposed adding a new term ''provisional discovery'' to mean that the operator has ''sufficient information to determine that an incident has likely occurred even if an evaluation has not been completed.'' They stated that this proposed change would address confusion with the proposed.

The American Medical Review Officers and the Pipeline Testing Consortium commented that the definition for confirmed discovery is an incident/accident notification rather than a confirmation, since it is based only on ''sufficient information to determine that a reportable event may have occurred.'' They recommend that this term be replaced with ''accident notification,'' and later allowing the operator to ''confirm the notification,'' rather than ''confirm the confirmed discovery.'' They also note that the terms incident, accident, and reportable event are used throughout the proposed changes, and they recommended using the single term ''accident'' in all of PHMSA's rules. The GPAC and the LPAC both recommended that PHMSA revise the definition of confirmed discovery as ''Confirmed Discovery: When it can be reasonably determined, based on information available to the operator at the time, that a reportable event has occurred, even if only based on a preliminary evaluation.''

Immediate Notice of Certain Incidents/Accidents (§§ 191.5 and 195.52)

The NTSB and the Pipeline Safety Trust disagree with the proposed requirement to file a second NRC report within 48 hours to confirm initial incident or accident information, irrespective of whether there are changes to that information. They stated that allowing operators 48 hours to file a follow-up report with more accurate information encourages operators to provide incomplete information initially and, instead, rely on the 48-hour second notification requirement to report more accurate incident data. They were concerned that this would delay receipt of information by the NTSB or other responding agencies that is needed to decide whether to mobilize a response.

In addition, the NTSB suggested that the second notification requirement would be significantly improved if PHMSA established a follow-up reporting requirement that would be triggered only ''when the pipeline operator has confirmed that previously reported information has significantly changed,'' and that PHMSA should include guidance on what constitutes a ''significant change,'' emphasizing the number of injuries and fatalities, evacuation zone changes, release amount, environmental impact, and infrastructure and equipment damage. They also suggested PHMSA should establish a cutoff time starting with the time of the first notification, since the benefit of extending the reporting period beyond a 12-hour timeframe is negligible for NRC notifications and changes in response to decisions by notified organizations.

The American Public Gas Association (APGA), the American Gas Association (AGA), and some pipeline operators commented operators cannot provide meaningful estimates of gas loss within one hour and recommended that the estimates should be included in the proposed 48-hour update to the one-hour notification. In addition, the AGA commented that the product loss requirement should be quantified at a loss of three million cubic feet or more. The Interstate Natural Gas Association of America (INGAA) and some pipeline operators suggested modifying the proposed language to include the ''initial estimate of amount of product loss, to the extent practicable.'' In addition, INGAA commented that PHMSA should not make the 48 hours reporting change effective until the NRC has the means to accept supplemental reports, that PHMSA should modify the definition of a ''reportable incident'' to only include significant events that include a sudden loss of pressure resulting in a large amount of gas released or a potential fatality or injury necessitating an in-patient hospitalization and only apply the one-hour timing to these significant events, and that PHMSA should extend the permissible timing for events requiring operators to report only on account of property damage estimates and minor leaks.

The American Petroleum Institute and the Association of Oil Pipe Lines (API–AOPL) and some operators commented that for the 48-hour notification, PHMSA should clarify that an operator may revise the initial estimate made to the NRC to reflect a zero sum regarding the amount of product released and the number of fatalities and/or injuries in connection with an incident in the event that a notification is made in error.

API–AOPL and some pipeline operators commented that calculating whether an incident is below the $50,000 threshold will be difficult within the one-hour time limit and that the cost threshold for notification should be eliminated. Magellan Midstream Partners commented that the $50,000 threshold should be removed, or as a reporting criterion it should be increased to $250,000 and a threshold volume of 100 barrels of released product. In addition, Magellan commented that PHMSA should consider expanding the reporting criteria to include the evacuation of residential or commercial properties and the closure of a transportation corridor such as a ship channel, railroad, state or federal highway, or city and county roads. If a threshold is retained at $50,000, Magellan recommended it should apply only to the cost of third party property damage, and not the expenses and cost of repairs to operator property.

Energy Transfer Partners suggested that the title for §§ 191.5 and 195.52 be retitled using a more accurate descriptive word such as ''prompt'' or ''timely'' in place of ''immediate.''

The GPAC proposed that PHMSA move the provision proposed in § 191.5(b)(5) addressing the amount of product lost to paragraph § 191.5(c).

3. PHMSA Response

With regards to the definitions, including the Advisory Committees' recommended definitions, the term ''confirmed discovery'' is in the 2011 Act and cannot be replaced by alternative terms. In addition, the terms ''incident'' and ''accident'' are in the 2011 Act, and replacing ''incident'' by ''accident'' throughout the Federal pipeline safety regulations would be out of the scope of this rulemaking action.

PHMSA proposed ''may have occurred'' in the definition of ''confirmed discovery'' to abide by the Congressional mandate requiring operators to alert the NRC to accidents and incidents despite not having a complete assessment. The purpose of the notification is to alert local, state, and federal agencies with notification at the earliest practicable moment so that emergency personnel or investigators can be dispatched quickly to mitigate the consequences of such an event. Without this requirement, each operator may have a different methodology in its procedures when responding to an accident or incident that could potentially take hours or days before an operator has completed its evaluation and determined that an accident or incident had in fact occurred. If an operator were allowed to wait for a definitive confirmation, based upon the procedures it has in place to identify and report accidents and incidents, even if the operator has sufficient evidence through its employees or the public, the intent of the Congressional mandate would be defeated. To address the public comments and the Advisory Committees recommendations, PHMSA has revised the definition of ''confirmed discovery.''

With regard to the immediate and secondary notifications, section 9(b)(3) of the 2011 Act directs PHMSA to require owners and operators of pipelines to revise their initial telephonic or electronic notice to the Secretary and the NRC with an estimate of the amount of the product released, an estimate of the number of fatalities and injuries, if any, and any other information determined appropriate by the Secretary within 48 hours of the accident or incident, to the extent practicable. Therefore, PHMSA proposed these requirements based on the 2011 Act.

With regard to operators updating their reporting to the NRC, PHMSA has no authority to require the NRC to update operators' initial reports without generating a new report. Section 9(c) of the 2011 Act directs the NRC to update the initial report without generating a new report. PHMSA contacted the NRC to find out how the mandate could be met, and the NRC informed PHMSA that it would require a substantial amount of funding for the Center to have this capability; however, the 2011 Act does not allocate funding for this mandate.

With regard to changing the reporting thresholds for both gas and hazardous liquid pipelines, the NPRM did not address them and they are out of scope of this rulemaking action.

B. Cost Recovery for Design Reviews

1. PHMSA's Proposal

PHMSA proposed to amend the Federal pipeline safety regulations to prescribe a fee structure and assessment methodology for recovering costs associated with design reviews of new gas and hazardous liquid pipelines with design and construction costs totaling at least $2,500,000,000 or that contain new and novel technologies.

2. Summary of Public Comment

On Proposed Definition of ''New and Novel Technologies'' (§ 190.3)

Many industry groups including API–AOPL commented that definition of ''new and novel'' is overly broad and a narrower definition should be provided in the final rule. The AGA and some pipeline operators commented that they are concerned that an operator would undergo an extensive documentation and submittal process and enter into a Master Agreement for cost recovery regardless of the scope and size of impact of the new or novel technology, and recommended specifying that the new and novel technology would be defined as requiring a special permit per 49 U.S.C. 60118(c).

INGAA and some pipeline operators also commented that the definition of ''new or novel technologies or design'' exceeds the intent of Congress' authorization because Congress only intended to authorize cost recovery for facility design reviews only and did not intend to authorize cost recovery for any potential review or inspection, including events occurring after design and construction are complete, such as the development of operational procedures or routine enforcement audits. These commenters note that conducting pipeline inspections or reviewing operational procedures should not be included in the cost recovery methodology.

Both Advisory Committees recommended revising the definition of new and novel technologies to mean ''any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not 'new or novel technologies.'''

On Applicability (§ 190.403)

API–AOPL and Kinder Morgan requested clarification from PHMSA whether the $2,500,000,000 threshold only applies to regulated assets in a master project that contains both assets regulated by the Department of Transportation and non-Department of Transportation regulated assets within the total investment. In addition, they stated that the proposed monetary threshold should only include design, material, and construction costs, and that operator overhead costs (*e.g.,* engineering, legal, right-of-way acquisition work) should be excluded from calculating the proposed threshold. Also, they requested that PHMSA modify the language proposed in § 190.403(c) to reference the appropriate section of the pipeline safety regulations for each review or inspection activity PHMSA performs as part of any safety design review.

Energy Transfer Partners asked if PHMSA intends for operators to make notification of all projects meeting the requirements, and commented that PHMSA should develop a process outside of a rulemaking whereby new and novel technologies can be expeditiously evaluated and broadly approved for use. Energy Transfer Partners also commented that it is not clear whether a single notification or multiple notifications are required. In addition, Energy Transfer Partners asked what PHMSA means by ''To the maximum extent practicable.''

The Gas Processors Association (GPA) and FlexSteel commented that the proposed rule does not clarify whether identical new technology is reviewed once or multiple times, even if different operators would be able to use the technology at different times. They asked when technology and/or design are no longer considered ''new and novel.'' The GPA and FlexSteel requested that the provisions for ''new and novel technology or design,'' including the definition and applicable cost recovery sections, be deleted from the final rulemaking.

Spectra Energy Partners commented that PHMSA should include additional language that would make it clear that technologies that are addressed in consensus standards and incorporated by reference are not ''new or novel technologies.'' They also stated that the inclusion of ''operational procedures'' in the definition goes beyond the authority granted PHMSA in the Act, and requested it be removed and provided revision to the proposed language.

On Notifications (§ 190.405)

INGAA and Kinder Morgan commented that PHMSA should revise its proposal to commence design review when the operator submits notice of its proposal because many of the proposed trigger events occur too early in the construction process for a company to commit firmly to a project. Commenters stated that many of the documents PHMSA is asking an operator to submit for a design review are not actually available 120 days prior to the proposed event, and that some of the listed documents predate receipt of a Federal Energy Regulatory Commission or other authorizing certificate. Commenters suggested that a notification date following a more certain trigger, such as the date that a Federal Energy Regulatory Commission certificate is received, would allow for timely review while ensuring that the document repository is adequately populated.

Alyeska asked PHMSA to add language that provides an alternative to the 120-day period for unique situations and circumstances.

TransCanada commented that the proposed requirements are inconsistent with the current, more general requirement (§§ 191.22(c)(1)(i) and 195.64(c)(1)(i)) to notify PHMSA at least 60 days ''before the event occurs'' including construction, and that PHMSA should compare the proposed notification requirements to the current requirements as well as revisit or rescind the September 12, 2014, Advisory Bulletin concerning construction notifications to ensure consistency and clarity regarding both the triggering event for notification and the notification period.

Spectra Energy and Texas Pipeline Association Partners commented that PHMSA's proposed definition of ''commencement of construction'' is overly broad, creating conflicts and making compliance impracticable.

Both Advisory Committees recommended deleting the phrase ''permitting activities, purchasing, and right of way acquisition'' from this section.

On Master Agreement (§ 190.407)

Energy Transfer Partners commented that there seems to be a presupposition that PHMSA will review the project, and that PHMSA and the applicant will enter into a master agreement. This section should be conditional and only require such an agreement in cases where PHMSA decides to conduct a review and the project meets a criterion for cost recovery under § 190.403. This section should also provide for the operator to have audit rights covering invoices and supporting documentation.

On the Sample Master Cost Recovery Agreement

The AGA and some pipeline operators commented that the Master Agreement process should be reciprocal in nature, and PHMSA should be required to provide timely feedback and responses through contractual deadlines applicable to the agency with clearly defined expectations for both participants in the agreement. API–AOPL commented that alternatives should be available to an operator that objects to the timeframe proposed by PHMSA to complete the safety design review; and whether the sample master agreement is meant to be authoritative or is open to comment and suggested revisions from the industry.

INGAA commented that PHMSA needs to revise its proposed cost recovery methodology by setting up a set fee schedule to put all regulated parties on notice of the projected costs and time involved in the review to help inform an operator's decision to use new technology and, therefore, seek agency design review and approval.

INGAA commented that PHMSA should consider a firm end point for design cost reimbursement when the pipeline is in-service. INGAA went on to say that PHMSA should revise its Master Cost Recovery Agreement in paragraph A(1) by stating that the review period commences when the operator submits notice of its proposal and that the agency should include examples of the type of other costs included under this section. INGAA also states that PHMSA should revise the termination date referenced in paragraph E(10) of the sample Master Cost Recovery Agreement to state ''the earlier of the termination of the review or the date the project is in-service.'' INGAA commented that the regulated community must be able to determine the range of costs and time involved prior to committing to a project. INGAA went on to say, at a minimum, operators must be aware of the maximum potential costs charged for a design review. Without this critical information, the operator cannot determine whether the costs and time for review make it feasible to continue with the project. If PHMSA moves forward with this proposal without modification, it would dissuade operators from using advances in design and technology.

The GPA commented that the terms and conditions of the proposed Master Cost Recovery Agreement do not relate to activities related to the reach and validation of new or novel technology or design. The GPA commented that it does not believe it was PHMSA's intent, but requests that the language for the Master Cost Recovery Agreement be amended to clarify that any cost recovery will be limited to the actual cost of the project review, including only the personnel directly involved in the review. The GPA commented that the Agreement also lacks any deadlines or obligations for PHMSA to meet and therefore, any agreement that requires a payment to be made for services should include parameters to ensure the review is timely. The GPA states that this will ensure the proposal moves through the process in a prescribed time period as long as the operator delivers the materials and responses necessary for PHMSA to move forward.

TransCanada commented that the Master Agreement does not state under what circumstances the agreement would end; the list of required provisions is a ''minimum'' list, and PHMSA should clarify what other provisions would be included in the future for specific projects and whether operators would be able to negotiate the inclusion or exclusion of any provisions, and asked how a Master Agreement would be implemented for projects with long development cycles.

On Fee Structure (§ 190.409)

The AGA and some pipeline operators commented that in order for operators to properly plan and budget for the design review, there should be a defined maximum for cost recovery of each design review that is subject to modification by mutual agreement.

Energy Transfer Partners commented that the described fee structure needs to be clear, complete and agreed upon between PHMSA and the operator from the outset. As written, it is not clear that the fee structure cannot be unilaterally modified during the period of the review.

On Billing and Payment (§ 190.411)

Energy Transfer Partners commented that the operator must have the right to not only verify the calculations, but also audit the bases for the calculations—time and activity reports, expense receipts, et cetera—in much the same way the operator monitors and approves time, material and expense reimbursements to its own employees and contractors.

3. PHMSA Response

With regard to comments on definition of ''new and novel'' being overly broad, PHMSA has revised the definition by adding ''for new construction.'' The revised definition reads as: ''*New and novel technologies* means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not 'new or novel technologies.' '' This new definition also ensures that technologies are not reviewed multiple times.

Procedure reviews of the design, materials used, testing, inspections of materials and construction, and start-up operational procedures are all a part of PHMSA's Code inspections for new construction. PHMSA believes that the new definition addresses the comments received. With regard to comments on whether the Master Cost Recovery Agreement process is reciprocal, PHMSA has included facility costs that are part of the normal tariff rate recovery process.

Regarding comments that conducting pipeline inspections or reviewing operational procedures should not be included in the cost recovery methodology, PHMSA agrees for existing pipelines. However, conducting pipeline inspections or reviewing operational procedures are a main function of PHMSA inspections for new pipeline facilities. In most cases, pipelines of this cost magnitude ($2.5 billion) are in new geographical areas with new operational personnel. The time needed to conduct these inspections normally takes much more time and dedication of PHMSA inspection staff and, therefore, need to be included in the cost recovery methodology.

With regard to comments from the Advisory Committees and other stakeholders regarding trigger events occurring too early in the construction process for a company to commit firmly to a project, PHMSA agrees that some of the proposed requirements need not be included and has modified § 190.405 to exclude permitting activities, material purchasing, and the right of way acquisition from the notification requirement.

With regard to the Master Cost Recovery Agreement not relating to activities related to the reach and validation of new or novel technology or design, the Master Cost Recovery Agreement detailed in § 190.407 was provided as a sample and would be tailored to specific requests to recover PHMSA costs of personnel involved in the review of the new or novel technology.

Also, the Advisory Committees recommendations agree with PHMSA's responses to the public comments.

C. Operator Qualification Requirements and NTSB Recommendations Related to Control Room Staff Training

1. PHMSA's Proposal

PHMSA proposed to amend the Federal pipeline safety regulations in 49 CFR parts 192 and 195 relative to operator qualification requirements, to cover new construction, add clarification for covered tasks, clarify training and documentation requirements, and add program effectiveness requirements for operators to gauge the effectiveness of the OQ programs. The amendments to the OQ regulation also extend OQ requirements to operators of Type A gathering lines in Class 2 locations and Type B onshore gas gathering lines.

The amendments also address the NTSB recommendations to extend operator qualification requirements to control center staff involved in pipeline operational decisions (P–12–8) and requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes (P–12–7).

2. Public Comments and PHMSA's Response on Scope and Definitions (§§ 192.801 and 195.501, and §§ 192.803 and 195.503), Qualification Program (§§ 192.805 and 195.505), Program Effectiveness (§§ 192.807 and 195.507), and Recordkeeping (§§ 192.809 and 195.509)

PHMSA received several comments on the new scope of operator qualifications (OQ), its definitions, operator qualification programs, program effectiveness, and OQ recordkeeping. However, during the rulemaking process, a decision was reached to not move forward with revised OQ requirements in order to further evaluate the costs and benefits of this issue. This decision had no bearing on the proposed regulations regarding control room team training requirements; the comments received on that issue, as well as PHMSA's response, are discussed below.

Therefore, PHMSA is delaying final action on the provisions regarding (1) OQ scope and definitions as they were proposed at §§ 192.801 and 192.803 under subpart N for the natural gas pipeline regulations and at §§ 195.501 and 195.503 for subpart G for the hazardous liquid pipeline regulations, respectively; (2) qualification programs as they were proposed at §§ 192.805 and 195.505 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively; (3) OQ program effectiveness as they were proposed at §§ 192.807 and 195.507 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively; and (4) OQ recordkeeping as they were proposed at §§ 192.809 and 195.509 for the natural gas pipeline regulations and the hazardous liquid pipeline regulations, respectively.

PHMSA notes that revised OQ requirements will be published in a subsequent final rule in the near future, and it will consider and discuss, at length, all of the comments received for each of the topic areas listed above along with the recommendations of the Pipeline Advisory Committees, in that final rulemaking.

3. Summary of Public Comment on Control Room Management (§§ 192.631 and 195.446)

The NTSB commented that it accepts PHMSA's plan to codify the training guidance previously issued as an advisory bulletin and, therefore, agrees with the proposed changes related to operator qualifications.

The AGA requested that PHMSA allow 12 months before the final rule becoming effective, and that in § 192.631(h)(6) the operator should be allowed to determine who should be involved in the team training exercises and suggested edits to the proposed regulatory language accordingly. With regards to the proposed roles and responsibilities in § 192.631(b)(5), it requested PHMSA clearly define what is meant by 'direct' and 'supersede' in context of interacting with a controller and provided suggested edits to the proposed language.

API–AOPL requested that currently qualified workers should not be affected by this rule and, therefore, the workers should be re-qualified at the next, regular requalification scheduled interval.

Enterprise suggested that the proposed rule be modified to read as, ''the roles and responsibilities of others that could provide operational direction or guidance when a controller is performing a specific action that falls under an operator's OQ program.'' In addition, Enterprise suggested a new subparagraph (h)(7) be included in §§ 192.631 and 195.446 to include an approval process to address when a controller's decision is to be superseded.

The GPA commented that there is disconnect between the stated intent in the preamble and the actual language of the proposed rule and that the language used to describe the intent and purpose of the change differs in a meaningful way. The GPA commented that the ''roles and responsibilities'' are already defined by the current provision of subpart (b) of the respective Code; therefore, establishing a strict list of those who can override a controller could potentially paralyze a controller in an abnormal, or emergency, situation, which no operator or agency wants. The proposed new training requirement for those potentially interacting with controllers is overly broad, which potentially results in extensive unintended consequences. In addition, a bullet states PHMSA is proposing to ''modify operator qualification requirements including addressing a NTSB recommendation to clarify OQ requirements for control rooms . . .'' However, there is no reference found in the OQ section of the proposed rules; therefore, PHMSA should issue a statement in the final rule that the changes made to control room management will not have an impact on an operator's future OQ program.

Magellan commented that OQ requirements should focus on those that directly perform the duties of the control room operator because there is no discernible benefit or advantage of expanding OQ requirements to include others who do not directly perform the duties of the Control Room Operator. Also, the roles and responsible of others who have the authority to direct or supersede specific technical actions needs to be limited to direct line supervisor and management personnel—as proposed in § 195.446(b)(5), the roles, responsibilities, and qualifications of ''others'' is overly broad.

Midwest Energy Association commented that it supports the use of team training for control room training but the requirement should not be placed in the OQ section and should instead be located in the control room management § 192.631.

Northeast Gas Association commented that it does not agree with the scope for team training for control room emergency situations, and recommends that the operator should have the authority to determine which personnel types should be involved during team training. Also, PHMSA should confirm that team training is only required for personnel who interact with control center staff on an operational basis as opposed to personnel who interact with controllers on non-operational matters.

Paiute Pipeline Company and Southwest Gas Corporation commented that the proposed rulemaking under § 192.631(h)(6) is inconsistent with the NTSB safety recommendation P–12–7—the recommendation is specific and limited to control center staff during emergency conditions. Therefore, PHMSA should provide justification substantiating the need for the proposed changes in § 192.631(b)(5). Paiute Pipeline Company also asked PHMSA to clarify as to the meaning of ''specific technical actions of controllers.''

Thomas Lael Services supports the changes and commented that at the end of §§ 192.631(h)(6) and 195.446(h)(6), it would be more clear if PHMSA inserts a clarification sentence. It recommends the following, ''This training shall be included in the scope required by Subpart N in of this part'' for § 192.631(h)(6), with a corresponding change to § 195.446(h)(6) that references subpart G rather than subpart N.

TransCanada commented that for operators to conduct control room team training and exercises to include controllers ''and other individuals who would reasonably be expected to interact with controllers'' goes beyond the NTSB's July 25, 2012, recommendation to PHMSA; the phrase ''reasonably be expected to interact with controllers'' is vague and ambiguous and, therefore, that training should be limited to ''control center personnel,'' including those with the authority to direct or supersede the specific technical actions of a controller.

Vectren Energy Delivery of Indiana and Ohio commented that additional clarification is necessary for control room team training because it may involve numerous ''soft skills.''

Mr. Warren Miller commented that training as related to covered tasks should be required for initial evaluation/qualification, when a covered task has changed substantially, when someone has contributed to an accident, or no longer qualifies due to operator qualification issues. PHMSA should clarify the required training for contractor individuals performing covered tasks on an operator's pipeline facilities. In addition, training should be required for all evaluators to ensure that evaluations are performed on each individual measures (the required KSAs) for each covered task consistently. The training and criteria for evaluators should include tracking and measuring an evaluator's performance to ensure criteria and established training is effective. In addition, specific language should be added to ensure that an evaluator will only evaluate a single individual. Criteria should be added to establish guidelines on what past experience and training each evaluator has on the specific task or field to indicate the evaluator can evaluate an individual. In addition, PHMSA should require an audit program to ensure evaluators for both operator and contract personnel are performing the evaluations as required.

4. PHMSA Response on Control Room Management (§§ 192.631 and 195.446)

As to whether the operator should be allowed to determine who should be involved in the team training exercises and suggested edits to the proposed regulatory language accordingly, it remains the responsibility of the operator to define the training and qualification requirements for personnel performing covered tasks on their pipeline facility. This includes the requirement for operators to define personnel involved in team training exercises.

As to the comment that currently qualified workers should not be required to requalify solely as a result of promulgation of the proposed rule, the control room management establishes the need for certain procedures and operating practices that would need to be incorporated into an operator's qualification program. If the prior qualification includes and meets all applicable requirements of the control room management plan and associated activities, the individual in question does not need to requalify. The rule does not specify that individuals performing covered tasks would need to be requalified solely as a result of this rulemaking action.

As to the suggestion that the terms ''direct'' and ''supersede'' in §§ 192.631(b)(5) and 192.446(b)(5) of the proposed rule be clearly defined, and to comments that these sections be ''modified,'' if field operations employee and supporting engineers who provide information or general advice to a controller are considered ''directing'' a controller on a specific action as suggested by the commenters, then these individuals are directing and superseding the controller's authority. In addition, while the control room management regulations call out certain specific individuals such as controllers, supervisors, and field personnel, understanding of the requirements of control room management and appropriate training is essential for other individuals that interact with controllers, particularly those that may affect the ability of a controller to safely monitor and control the pipeline during normal, abnormal, and emergency situations. Other individuals to which team training might pertain likely vary by operator and control room depending on specific procedures and roles in the control room, but they could include individuals such as technical advisors, engineers, leak detection analysts, and on-call support. These individuals are typically already trained in their specific job function and have some awareness of the roles and responsibilities of controllers. In many cases, they are also included in discussions or meetings that involve control room personnel. However, these individuals may not always get together to be trained on how to work together as a team. Therefore, to provide for a controller's prompt and appropriate response to operating conditions, an operator must define the roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

As to the suggestion that a new subparagraph (h)(7) be included in §§ 192.631 and 195.446 to include an approval process to address when a Controller's decision is to be superseded, because this was not proposed, it is out of the scope of the final rule.

As to the comment that PHMSA should issue a statement in the final rule that the changes made to control room management will not have an impact on an operator's future OQ program, additional requirements have been added to the control room management regulation to address the NTSB recommendation, including training. The OQ requirements prescribe the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility, and include training.

As to the comment that OQ requirements should focus on those that directly perform the duties of the control room operator because there is no discernible benefit or advantage of expanding OQ requirements to include others who do not directly perform the duties of the control room operator, issues identified from Marshall (for hazardous liquid) and to an extent San Bruno (for gas) in the NTSB report seem to disagree. Also, the OQ requirements prescribe the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. It remains the responsibility of the operator to identify covered tasks.

As to the comment that the requirement should not be placed in the OQ section and should instead be located in the control room management § 192.631, team training is under § 192.631. It remains the responsibility of the operator to define the training and qualification requirements for personnel performing covered tasks on its pipeline facility. It is up to the operator as to how it documents the processes/procedures and records associated with this requirement.

As to the comment that the operator should have the authority to determine which personnel types should be involved during team training, it remains the responsibility of the operator to define the training and qualification requirements for personnel performing covered tasks on their pipeline facility. Team training might vary by operator and control room depending on specific procedures and roles in the control room.

As to the comment that team training is only required for personnel who interact with control center staff on an operational basis as opposed to personnel who interact with controllers on non-operational matters, while this may be true for some situations, some scenarios where non-operational type personnel/matters may need to be included. However, it is up to the operator to define who exactly is included and with ultimate determination of adequacy up to the inspector.

As to the comment that the proposed rulemaking under § 192.631(h)(6) is inconsistent with the NTSB safety recommendation P–12–7 because the recommendation is specific and limited to control center staff during emergency conditions and, therefore, PHMSA should provide justification substantiating the need for the proposed changes in § 192.631(b)(5) and clarify as to the meaning of ''specific technical actions of controllers,'' the NTSB recommendation is not specific to emergency conditions only. The recommendation as written is more generic to pipeline operations in general.

As to the comment that at the end of §§ 192.631(h)(6) and 195.446(h)(6) PHMSA should insert a clarification sentence referencing Subpart N in part 192 and Subpart G in part 195, it remains the responsibility of the operator to define the training and qualification requirements for personnel performing covered tasks on their pipeline facility, to include those performing control rooms related covered tasks. All operators are required to implement the OQ regulations per subpart N in part 192 and subpart G in part 195.

Regarding comments on control room team training and exercises to include controllers, PHMSA disagrees that this section is ambiguous and goes beyond the NTSB recommendation. For example, leak detection analysts that were raised as an issue in the NTSB report on Marshall might not be considered control center personnel by a number of operators.

As to the comment that additional clarification is necessary for control room team training because it may involve numerous ''soft skills,'' PHMSA will provide guidance in a separate document.

As to the comment that training as related to covered tasks should be required for initial evaluation/qualification, when a covered task has changed substantially, when someone has contributed to an accident, or no longer qualified due to operator qualification issues, it remains the responsibility of the operator to define the training and qualification requirements for personnel performing covered tasks on their pipeline facility.

As to the comment that PHMSA should clarify the required training for contractor individuals performing covered tasks on an operator's pipeline facilities, contractors face different OQ requirements. It is correct to say that contractors working for multiple pipeline operators may face multiple, and sometimes conflicting, requirements. This is why it is essential for each pipeline operator to have and effectively implement his/her own unique OQ program. Operator qualification programs must be specific to a pipeline operator and the covered tasks performed on the operator's facilities, taking into consideration the operator's methods of construction, operation, maintenance, and emergency response along with its unique tasks, equipment, and technologies utilized.

In addition, the Advisory Committees recommended editorial changes to §§ 192.631(h)(6) and 195.446(h)(6). PHMSA accepts the editorial changes and made the recommended changes accordingly.

D. Special Permit Renewal

1. PHMSA's Proposal

PHMSA proposed to amend § 190.341 of the Federal pipeline safety regulations to add procedures for renewing a special permit.

2. Summary of Public Comment

The Pipeline Safety Trust clarified that any renewal applications will be treated the same as current initial applications in that they will be public, published on the PHMSA Web site, and subject to NEPA, and therefore suggested revising § 190.341(d)(1) by replacing the word ''application'' with ''application or renewal.''

The AGA commented that the proposed language in § 190.341(e) is ambiguous and unclear as to its purpose and asked PHMSA to revise it.

INGAA and Spectra Energy Partners commented that PHMSA should reexamine the extent of the documentation it requires as part of the renewal process and should collect summaries of reports and high-level maps rather than more extensive records.

Energy Transfer Partners objected to the addition of the phrase ''for a period of time from the date granted'' in § 190.341(d)(2). They also objected to the proposed renewal process itself, described in § 190.341(f), as overly burdensome, duplicative and unnecessarily repetitive in the amount and nature of the material required, and noted that requiring additional aerial photography rather than depicting the requested boundaries and features on the operator's GIS background is not necessary.

FlexSteel commented that to be subject to the expiration or revocation without unjust reasons or adding additional stipulations after a special permit is approved jeopardizes the feasibility of the situation, or solution being sought by the operator. They requested that PHMSA should only review the special permit to confirm satisfactory performance by permitting continued pipeline operation and questioned why the request for renewal should be incumbent on the operator and require resubmittal of the information from the original request.

The requested information should be limited to class location and high consequence area information in tabular format; the ILI requirement should be changed to the most recent information; data integration drawings should not be required as part of the special permit renewal request; and aerial photography data would not provide any meaningful information and be deleted from the requirement.

Both Advisory Committees recommended PHMSA clarify that special permit renewals must be submitted 180 days prior to the grant expiration, limit aerial photography of pipeline segments where special permits affect public safety such as a class location special permit that allows a less stringent design factor in a populated area and allow operators to submit a summary of inline inspection survey results with permit renewals, and amend the language in in § 190.341(d)(1) by replacing the word ''application'' with the phrase ''application or renewal.''

3. PHMSA Response

PHMSA agrees that renewal applications should be treated the same as current initial applications in that they will be public, published on the PHMSA Web site, subject to NEPA, and published for comments on the **Federal Register**. Therefore, PHMSA revised the amendatory language in § 190.341(d)(1) by replacing the word ''application'' with ''application or renewal.''

With regard to PHMSA reexamining the extent of the documentation it requires as part of the renewal process, § 190.341(c) already has documentation requirements for special permit requests. PHMSA is requiring identical documentation for special permit renewal requests, too. PHMSA performs extensive technical analysis on special permit applications and typically conditions a grant of a special permit on the performance of alternative measures that would provide an equal or greater level of safety. PHMSA asks for summary information for operational, maintenance, and integrity conditions in the special permit.

With regard to aerial photography data requirement, PHMSA agrees with commenters and will require aerial photography of pipeline segments where special permits affect public safety, such as a class location special permit that allows a less stringent design factor in a populated area.

With regard to the comment that PHMSA should only review the special permit to confirm satisfactory performance by permitting continued pipeline operation, PHMSA's special permit renewals are a process to ensure the special permit conditions are being implemented and that the conditions continue to be suitable for pipeline safety, environmental protection, and in the public safety interest. Therefore, a requirement for renewal of special permits is necessary.

PHMSA made the following changes to the proposed amendatory language in response to the comments: In § 190.341(e)(1) no submittal date was provided. Therefore, the section is revised to make it clear that a special permit renewal must be submitted 180 days prior to the grant expiration. Also, in § 190.341(f)(1)(v)(F), the proposed language required ILI survey results. That language is revised to allow only a summary of the most recent ILI survey results to be submitted with the permit renewal.

Regarding the expiration requirement, the renewal process in § 190.341(f)(2) allows PHMSA to request additional operational, integrity or environmental information as needed to evaluate the special permit renewal. Also, PHMSA has the right to determine the period of time from the date granted to require renewal of the special permit to assure safety, environmental protection, and public interest. The safety needs for permit renewal time intervals will vary based upon the permit type, whether material, design factor, construction or operational.

The Advisory Committees agreed with PHMSA's responses to the public comments.

E. Farm Taps

1. PHMSA's Proposal

PHMSA proposed to amends the Federal pipeline safety regulations in 49 CFR part 192 to add a new § 192.740 to cover regulators and overpressure protection equipment for an individual service line that originates from a transmission, gathering, or production pipeline (*i.e.,* a farm tap), and to revise § 192.1003 to exclude farm taps from the requirements of the Distribution Integrity Management Program (DIMP).

2. Summary of Public Comment

The AGA cautioned PHMSA that the agency's current position that ''threats to typical farm taps are limited, and most are already addressed within part 192'' could be a slippery slope allowing for various assets within distribution systems to be exempt from DIMP simply because the risks are perceived as relatively low. The AGA commented that while this new proposed requirement may be appropriate for service lines not included in DIMP, it would be a redundant and cumbersome requirement for services lines whose risks are addressed holistically through integrity management.

Similarly, INGAA commented that distribution operators will likely want to treat farm taps as part of their distribution system, and that operators that exclusively operate transmission pipelines will see no value in creating a distribution program just for the farm tap. Therefore, operators should have the option of treating a farm tap as either distribution or transmission as long as the necessary safety and reporting requirements are met.

Operators NiSource, Inc., Northern Natural Gas Company, Southwest Gas Corporation, and TransCanada all agreed that PHMSA should allow an operator the option of keeping farm taps as part of its DIMP.

CenterPoint Energy requested that PHMSA allow operators to establish their own inspection intervals or operating procedures based on the risks associated with particular types or classes of farm taps; they note that § 192.740 is basically § 192.739 and, therefore, § 192.740 should include either the exemption or at the very least language including the limitation that an operator need only verify that a rupture disc with the correct range is installed at the location.

DTE Gas Company commented that there still are threats and risks associated with farm tap service line piping between the farm tap regulator assembly and the customer, and that PHMSA should consider limiting the exception proposed in § 192.1003(b) to the components of the farm tap regulator and valve assembly between the transmission, gathering, or production line and the service line pipe.

The GPA commented that as drafted, § 192.740(a) could be interpreted to exempt additional lines from the requirements of the section. The GPA also requested PHMSA clarify whether the proposal in § 192.1003(b) applies to a service line that directly connects with an upstream production, gathering, or transmission pipeline. In addition, PHMSA should provide a five-year interval for inspection of farm taps.

Kinder Morgan suggested that a farm tap be defined as ''a pipeline that maintains the same designation as the pipeline from which it originates (transmission, storage, gathering or production) and connects to a customer owned service line.'' They also requested that transmission gathering, or production pipeline operators should not be responsible for odorization unless it is currently provided as a service to the owner of the farm tap., and that the maintenance of any odorization along with pressure regulation, overpressure protection, or other facilities should be a ''grandfathered'' function and not a new requirement as part of the proposed rule.

MidAmerican Energy Company commented that the added inspection requirements for ''farm taps'' are significantly more than what is currently required for inspection by DIMP, and that, as proposed by AGA, PHMSA should continue to allow those operators that want to address these services through DIMP or PHMSA should allow a 60-month inspection cycle due to the low risk potential. In addition, PHMSA should give consideration to removing or modifying the 60 psig requirement for pressure of services off of transmission mains for commercial/industrial customers.

Texas Pipeline Association commented that it supports a revision to § 192.1003 that states farm taps directly connected to upstream production, gathering, or transmission pipelines would be excluded from the DIMP requirements. Also, it supports the proposal in § 192.740 to require the inspection and testing of regulators and other over pressure protection equipment.

Vectren Energy Delivery of Indiana and Ohio commented that in order to comply with the proposed rule, retrofits of farm taps would be required because the current standard for a High Pressure Service does not call for a block valve upstream of the pressure relief valve. The test and inspection of the set point of the device is not possible without removing the device or modifying the fabricated assembly. They also comment that the definition of a farm tap is not clear and that current risk models in DIMP result in additional accelerated actions for farm taps when elevated risk scores are noted. Therefore, PHMSA should allow farm taps to remain within DIMP and not mandate a prescribed inspection, or adjust the language in the proposed rulemaking to allow the operator the choice to leave them in DIMP or remove them from the DIMP and follow a mandated inspection frequency.

The GPAC recommended that PHMSA amend the language defining farm taps to service lines ''directly connected to'' production, gathering, or transmission pipelines in both §§ 192.740 and 192.1003(b). The committee also requested that rupture disks be exempted from relief devices required to be inspected.

3. PHMSA Response

NAPSR originally requested the exclusion to exclude farm taps from the DIMP requirements, which PHMSA agrees with. Farm taps are single pipelines that deliver gas to a farmer or other landowner mostly in Class 1 locations, excluding them from the

DIMP requirements. However, these lines are still subject to inspection requirements for pressure regulating/limiting devices, relief devices, and automatic shutoff devices, which would provide adequate safety protection. Therefore, PHMSA is excluding farm taps from the DIMP requirements.

Regarding comments asking that farm taps be regulated at the operators' choice—under DIMP or as proposed, uniform compliance requirements for farm taps are necessary to be enforceable. In addition, some comments requested that operators have the option of treating a farm tap as either distribution or transmission; however, farm taps are distribution service lines, and operators do not have the option to treat distribution service lines as transmission lines. However, this rule decreases the compliance burden for operators by excluding farm taps from the DIMP requirements. As to the inspection requirements for the farm tap safety devices, these safety devices are not new requirements for the safe operation. Therefore, these devices need to be inspected and maintained to ensure safe operation.

With regard to comments for operators to establish their own inspection intervals, compliance cannot be effective if operators can choose their own inspection intervals because the requirements would be unenforceable. Inspection requirements are prescriptive regulations and are not intended to be risk-based or operator established inspection intervals. In addition, extending the inspection interval is not in the interest of safety, and PHMSA is keeping the interval as proposed at three years.

Regarding comments that this section could be interpreted exempt additional lines from the requirements of the section, PHMSA revised the section to read ''any service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.'' In addition, PHMSA has revised § 192.1003(b) to reflect the comment.

Regarding comments that the definition of a farm tap is not clear, PHMSA did not propose a definition for a farm tap. A farm tap is a distribution service line. Regarding comments on grandfathering of odorization and other responsibilities, there is no grandfathering possible for something that has always been required, including requirements for odorizing distribution service lines.

Regarding comment that that rupture disks be exempted from relief devices required to be inspected, PHMSA agrees with the commenter and rupture disks are exempt from the § 192.740(b) requirement.

The Gas Advisory Committee agreed with PHMSA's responses to the public comments.

F. Reversal of Flow or Change in Product

1. PHMSA's Proposal

PHMSA proposed to expand the list of events in §§ 191.22 and 195.64 that require electronic notification to include the reversal of flow of product or change in product in a mainline pipeline. This notification is not required for pipeline systems already designed for bi-directional flow, or when the reversal is not expected to last for 30 days or less. The proposal would require operators to notify PHMSA electronically no later than 60 days before there is a reversal of the flow of product through a pipeline and also when there is a change in the product flowing through a pipeline. Examples include, but may not be limited to, changing a transported product from liquid to gas, from crude oil to HVL, and vice versa. In addition, a modification is amended to §§ 192.14 and 195.5 to reflect the 60-day notification and requiring operators to notify PHMSA when over 10 miles of pipeline is replaced because the replacement would be a major modification with safety impacts.

2. Summary of Public Comment

API–AOPL requested a 30-day notice period in the final rule or flexibility for unforeseen events that necessitate extended or immediate reversals or product conversions. API–AOPL stated that PHMSA should clarify if an operator is required to report the reversal or product conversion 60 days prior to the event or 60 days prior to when the reversal or conversion work begins. API–AOPL also requested that PHMSA clarify whether or not the agency intended that operators may commence preparations for a reversal or conversion prior to making the proposed report to the agency. In addition, they requested the notification be required only prior to physical changes being made to the system, where business confidentiality agreements restrict the knowledge of such changes.

INGAA commented that the proposed notification requirement should apply only to permanent flow reversals where an operator must change or modify its compressor facilities and related piping to accommodate a flow reversal, in which the pipeline needs the Federal Energy Regulatory Commission certificate authorization under the Natural Gas Act. For non-Federal Energy Regulatory Commission regulated pipelines, INGAA notes PHMSA would need to create another notification trigger. For non-bi-directional pipelines, the 60-day notification should be waived for an emergency or under unforeseeable circumstances.

Alyeska noted that PHMSA proposed the addition of ''replacement'' to § 195.64(c)(1)(ii), such that the regulation would require the 60-day notification for ''construction of 10 or more miles of a new or replacement pipeline.'' PHMSA's guidance and advisory bulletin ADB–2014–03 interprets the current § 195.64(c)(1)(ii) as including replacement of 10 or more contiguous miles of line pipe in an existing pipeline, and Alyeska requested PHMSA add ''contiguous'' to the new proposed § 195.64(c)(1)(ii) to reflect PHMSA's interpretation, so that multiple projects resulting in replacement of shorter pipeline segments that collectively add up to 10 or more miles are not considered subject to this rule.

DTE Gas Company commented that the word ''product'' should not apply to gas pipelines as this term is normally associated with hazardous liquid lines in § 191.22(iv). They also requested PHMSA consider excepting the notification requirement for pipelines operating in bi-directional flow modes in conjunction with storage field injection and withdrawal cycles.

Enterprise commented that PHMSA should revise the notification requirement for ''reversal of flow or change in product'' to 30 days and provide an exception from the notification requirement for lines that have previously carried other commodities or that will not require significant modification to change product service. They also requested PHMSA include additional flexibility in the regulation to provide for emergency conditions that require reversals or product conversions where advance notice is not possible.

The GPA suggested that a provision should be added to permit reporting in cases of unplanned or unanticipated reversals.

Kinder Morgan commented that there are numerous instances where the new reporting criteria cannot be reasonably met for natural gas pipeline system, since the pipeline operating conditions are based upon varying customer demand and may change quickly due to such factors as weather changes, other pipeline outages or emergencies, and even changes in daily customer demand requirements. They requested that changes in flow direction related to seasonal or customer demands and that last more than 30 days should be excluded from this reporting requirement. These flow direction changes have been routinely performed for many gas pipeline systems for a number of years and are a normal operating practice; due to the number of new sources of natural gas, pipeline operators that have the capability of reversing their flow direction must have the flexibility to meet these varying demands as they arise and would not be reasonably able to meet a 60-day reporting requirement.

TransCanada requested that PHMSA re-examine the September 18, 2014, Advisory Bulletin and associated Guidance to Operators Regarding Flow Reversals, Product Changes and Conversion to Service to identify which requirements should be incorporated into the regulations then retire the September 18, 2014, Advisory Bulletin and Guidance.

3. PHMSA Response

With regard to PHMSA allowing a 30-day notice period, for operators to reverse the flow of most existing pipelines requires many months of planning, facility modifications, pipeline pressure testing, and other repairs. Operators also have to go through the process of getting new tariffs through a rate case process, which takes a time interval that is longer than the 60 days. Therefore, PHMSA is keeping the 60-day notice period.

With regard to PHMSA clarifying if an operator is required to report the reversal or product conversion 60 days prior to the event or 60 days prior to when the reversal or conversion work begins and business confidentiality agreements restrict the knowledge of such changes, the new paragraph requires 60 days prior to the reversal event, and § 190.23(c)(1)(i) already requires notification when costs are $10 million or over. With regard to notification requirement applying only to permanent flow reversals where the pipeline needs the FERC certificate authorization and for non-bi-directional pipelines for emergency or under unforeseeable circumstances, the flow reversal notification is for flow reversals over 30 days, unless an emergency event exists.

With regard to multiple projects resulting in replacement of shorter pipeline segments that collectively add up to 10 or more miles, a pipeline with many segments and compressor stations that are being modified for flow reversal would be considered the same reversal project.

Changes in flow direction that are related to seasonal or customer demands and last more than 30 days are not applicable to existing bi-directional pipelines. This requirement is applicable for existing one direction pipelines that are modified for bi-directional or reverse flow.

With regard to PHMSA's Advisory Bulletin and associated Guidance to Operators Regarding Flow Reversals, Product Changes and Conversion to Service dated September 18, 2014, the advisory bulletin is based upon 49 CFR parts 192 and 195 and lessons-learned/findings from inspections of operator facilities for construction, operations, maintenance, and integrity management and, therefore, is still applicable.

The Advisory Committees agreed with PHMSA's responses to the public comments.

G. Pipeline Assessment Tools

1. PHMSA's Proposal

Section 195.452 of the pipeline safety regulations specifies requirements for assuring the integrity of pipeline segments where a hazardous liquid release could affect a high consequence area (referred to in this rule as ''covered segments''). Among other requirements, the regulations require that operators of covered segments conduct assessments, which consist of direct or indirect inspection of the pipelines, to detect evidence of degradation. Section 195.452(d) requires operators to conduct a baseline assessment of all covered segments. Section 195.452(j) requires that operators conduct assessments periodically thereafter.

This rulemaking action incorporates by reference the following consensus standards into 49 CFR part 195: API STD 1163, ''In-Line Inspection Systems Qualification Standard'' (April 2013); NACE Standard Practice SP0102–2010 ''Inline Inspection of Pipelines'' NACE SP0204–2008 ''Stress Corrosion Cracking Direct Assessment;'' and ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification'' (2010). Also, PHMSA allows pipeline operators to conduct assessments using tethered or remote control tools not explicitly discussed in NACE SP0102–2010, provided the operators comply with applicable sections of NACE SP0102–2010.

2. Summary of Public Comment

The NTSB agreed that incorporating by reference the industry consensus standards listed in Section VII of the NPRM will improve operator pipeline assessment consistency, accuracy, and quality. Requiring a written SCCDA plan to include the pre-assessment as outlined in the NACE standard practice RP0204 would provide owner/operators with valuable information and allow them to thoroughly assess vulnerabilities to stress corrosion cracking. Furthermore, the proposed requirement that the piping assessment plan contain a ''data gathering and integration'' element addressing the four, listed factors will further improve the SCCDA process. Also, the NTSB agreed that the NACE standard practice for conducting SCCDA combined with the written plan requirements are more comprehensive and rigorous than the current regulatory requirements.

The AGA supports the incorporation of NACE SP0204–2008: Stress Corrosion Cracking (SCC) Direct Assessment Methodology by reference in pipeline safety regulations, but not with the additional proposed requirements to NACE SP0204–2008. The AGA contends that NACE SP0102–2010 does not provide detailed procedures that are applicable in all situations on all pipelines and instead provides general recommendations. And that the ANSI/ASNT ILI–PQ–2010 should not be incorporated by reference in part 195 because it is not common practice for company personnel who may review data provided by vendors to comply with the qualifications outlined by this standard. The AGA does not support the proposed regulatory language in § 195.591 because it removes the ability for operating personnel to use their engineering judgment when outlining the company's strategy for ILI.

API–AOPL requested PHMSA to clarify any instances where the requirements outlined in SP0204–2008 are intended to serve as industry guidance. PHMSA's proposed incorporation of SP0204–2008 is a significant extension of the intent underlying the SCCDA data collection process. Therefore, PHMSA should clarify the inclusion of SP0204–2008, Table 2 in the data gathering process. They also requested PHMSA provide a technical justification for the proposed minimum number of excavations, as well as justification for incorporating API STD 1163 (2005) when that standard has been updated recently. The proposal defining non-significant SCC in accordance with NACE SP0204–2008 is out of date and creates ambiguity both in terms of interpretation and enforcement; therefore, PHMSA should use the Canadian Energy Pipeline Association's (CEPA's) severity criteria, as it provides clear guidance on appropriate actions to address SCC based on levels of SCC severity. For ILI tool standards proposed in § 195.452, PHMSA should issue additional clarifying guidance reemphasizing the need to determine the appropriate assessment technology based on an evaluation of the segment specific risks associated with each portion of the line.

Chevron Pipe Line Company commented that each proposed standard for incorporation by reference is supported by an array of associated material that is taken into consideration based on the many factors involved when assessing pipeline conditions, and therefore, PHMSA should provide adequate time beyond the comment deadline and before the final rule is issued for industry and regulatory stakeholders to adequately assess the proposal for feasibility.

Energy Transfer Partners commented that in § 195.452, regarding the capabilities of ILI tools, the operator should be able to choose tools that are appropriate for the threats identified or to obtain the data required, and it is understood that the operator needs to be able to justify such decisions. Energy Transfer Partners also commented that the mitigation requirements proposed in § 195.588(c)(4)(ii) appear to be mandated with no technical basis and are contrary to much of the expert technical opinion on such testing. The stress level achieved during the ''spike'' portion of the hydrostatic test should be an engineered pressure defined by the operator to achieve some stated goal. The operator should be able to set that goal, and the corresponding pressure, to balance the various factors involved, including post-test operating pressure, retest interval and potential activation of otherwise stable anomalies. The duration of the ''spike'' portion of the test should likewise be engineered based upon similar factors. There is technical literature and technical opinion that, particularly at the very high pressures proposed by PHMSA, holding those pressures much beyond 5 minutes, and certainly beyond 10, provides no additional benefit. They comment that PHMSA has presented no basis or justification for a 30-minute hold, and that PHMSA has not presented a technical justification for the requirement of a subpart E hydrostatic test to be conducted as a continuation of the ''spike'' portion of the test. Properly engineered pressure testing can be an effective mitigation tool for stress corrosion cracking. However, a ''one size fits all'' mandated approach to such testing is not appropriate and is not the most effective way of achieving effective mitigation and overall improvement in assurance of integrity. The pipeline operator should be responsible for determining the required testing parameters based upon the specifics of the line being tested and the established goal of the testing.

Enterprise commented that with respect to the proposed ILI tools in § 195.452(c) and (j), PHMSA should revise the proposal to clarify that a crack tool is not required for every ILI assessment or reassessment and clarify that operators need only consider the recommendations of the ILI consensus standards proposed to be incorporated by reference. They also commented that PHMSA should modify the proposed language similar to existing natural gas integrity management requirements in § 192.921(a)(1). In addition, they requested § 195.591 be clarified to state that operators need only ''consider'' the recommendations in the proposed incorporation by reference standards, and that PHMSA should incorporate the most current version of API 1163 (2010), or risk inconsistency and/or conflict with NACE RP0102 because the 2005 API 1163 standard cross-references an older (2002) version of NACE RP0102, but PHMSA's proposed incorporation risks requiring actions that are inconsistent with the 2010 NACE version of that standard which is proposed to be incorporated by the regulation.

Northeast Gas Association commented that it is concerned about additional requirements above and beyond NACE SP0204–2008 that are being proposed, such as PHMSA's proposal in § 195.588(c)(1) to require gathering and evaluating data related to stress corrosion cracking at all sites an operator excavates during the conduct of its pipeline operations both within and outside covered segments.

Thomas Lael Services provided suggested editorial comments for ILI of pipelines in proposed § 195.591 and provided additional comments and new proposals into part 192.

The LPAC recommended adopting the newer, April 2013 version of the API STD 1163, ''In-Line Inspection Systems Qualification Standard.''

3. PHMSA Response

The additional requirements were generated by PHMSA subject matter experts based on their lessons learned from the integrity management program, and expert presentations of public workshops on stress corrosion cracking, risk, and new construction. PHMSA is incorporating API STD 1163 (April 2013); NACE Standard Practice SP0102–2010, NACE SP0204–2008, and ANSI/ASNT ILI–PQ–2010 into the regulations to provide clearer guidance for conducting integrity assessments with ILI. These standards complement each other, and they will promote a higher level of safety by establishing a consistent methodology to qualify the equipment, people, processes, and software utilized by the ILI industry.

PHMSA is incorporating NACE SP0204–2008 into part 195 because it provides comprehensive, up-to-date guidelines on conducting SCCDA. It is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S, and PHMSA has concluded the quality and consistency of SCCDA conducted under integrity management requirements would be improved by requiring the use of NACE SP0204–2008. The NACE standard provides additional guidance on: The factors that are important in the formation of stress corrosion cracking on a pipeline and what data should be collected; additional factors, such as existing corrosion, which could cause stress corrosion cracking to form; comprehensive data collection guidelines including the relative importance of each type of data; requirements to conduct close interval surveys of cathodic protection or other above-ground surveys to supplement the data collected during pre-assessment; ranking factors to consider for selecting excavation locations for both near neutral and high pH stress corrosion cracking; requirements on conducting direct examinations including procedures for collecting environmental data, preparing the pipe surface for examination, and conducting Magnetic Particle Inspection (MPI) examinations of the pipe; and post assessment analysis of results to determine SCCDA effectiveness and to assure continual improvement.

PHMSA proposed to incorporate the 2005 API 1163 because at the time the notice of the rulemaking action was developed, the latest version of API 1163 was under development. PHMSA has evaluated the revisions made to the latest version of API 1163 and determined that the changes are not significant. Therefore, PHMSA is adopting API STD 2013 into part 195. However, adopting the Canadian Energy Pipeline Association's severity criteria is out of the scope of this rulemaking action.

PHMSA provides adequate time for industry and regulatory stakeholders to adequately assess the proposal for feasibility. The agency goes through a long process of analyzing all comments, discussing summary of comments at the Advisory Committee meetings that are open to the public and getting their recommendations and having internal review with PHMSA subject matter experts before issuing the final rule. PHMSA believes this process gives operators enough time to review the proposals.

With regard to inspection tools selections, operators always have option of using their alternative to these standards as long as the alternative tools meet equivalency or exceed the provisions in these standards.

If a pipeline includes legacy pipe or was constructed using legacy construction techniques, or the pipeline has experienced a reportable in-service accident since its most recent successful ''spike'' hydrostatic pressure test, due to an original manufacturing-related defect, a construction, installation, or fabrication-related defect, or a crack or crack-like defect, a spike pressure test would be required. Further, ongoing research and industry response to other PHMSA rulemaking actions is beginning to indicate that SCCDA is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to stress corrosion cracking defects, as ILI or hydrostatic pressure testing at test pressures that exceed those test pressures (*i.e.,* ''spike'' hydrostatic pressure test). Therefore, a ''spike'' hydrostatic pressure test is well suited to address stress corrosion cracking and other cracking or crack-like defects.

With regard to a crack tool not being required for every ILI assessment or reassessment and that operators need only consider the recommendations of the ILI consensus standards proposed to be incorporated by reference, operators always have the option to use their alternative to these standards as long as the alternative tools meet equivalency or exceed the provisions in these standards. These standards are incorporated in part 195 after lessons learned from past integrity management requirement in place for years; recent high profile incidents in Marshall, MI, San Bruno, CA, and Mayflower, AR, and recommendations from the NTSB to address crack like defects, stress corrosion cracking and seam corrosion issues, have indicated that current integrity management requirements do not address all anomalies in the pipeline. Further, PHMSA is revising § 195.452(c)(1)(i)(A) to clarify the fact that operators should select the appropriate tool type to address the specific threats relative to their pipeline segments.

The LPAC agreed with PHMSA's responses to the public comments.

H. Post-Accident Drug and Alcohol Testing

1. PHMSA's Proposal

PHMSA is modifying §§ 199.105 and 199.225 by allowing exemption from post-accident drug and alcohol testing only when there is sufficient information that establishes the employee(s) had no role in the accident.

PHMSA's regulations required the documentation of decisions not to administer a post-accident alcohol test but the requirement to document decisions not to administer a post-accident drug test was only implied in the regulation, and the implied requirement is generally followed. PHMSA is amending the post-accident drug testing regulation to require documentation of the decision and to keep the documentation for at least three years.

2. Summary of Public Comment

The NTSB commented that it believes the proposed change is responsive to its recommendation.

The APGA commented that this requirement could be misinterpreted to require the operator to document actions of every utility employee after a reportable incident occurs. PHMSA uses the terms ''surviving covered employee'' and ''whose performance of a covered function'' to clarify that this proposed requirement only requires the operator to consider testing those employees who performed covered functions at the location of the incident either when the incident occurred or for some time period immediately prior to the incident; however, it does not require documentation for employees working elsewhere on the system. The APGA commented that it supports the proposed electronic submittal requirement for each annual management information system for the operator's drug and alcohol testing program.

API–AOPL commented that the proposed rule for post-accident drug and alcohol testing does not discuss whether PHMSA has a specific process in mind for those operators requesting an exemption from the proposed test-reporting requirement and that PHMSA should clarify further on the process envisioned by the agency. Additionally, they requested PHMSA articulate whether it intends to create one standardized form to be used by all industry operators to document the decision to not administer a post-accident test, or whether individual operators will be required to generate their own forms.

Enterprise commented that PHMSA should revise the post-accident drug and alcohol testing proposal to state affirmatively which employees must be tested under the regulations, and that PHMSA should generate a standard form to be used for decisions not to test, to avoid inconsistency both in application and reporting.

The American Medical Review Officers and the Pipeline Testing Consortium recommended that in §§ 199.105(b) and 199.225(a)(1) PHMSA use the same phrase ''contributed to the accident'' in the second sentence as was used in the first rather than the employee's ''role in the cause . . . of the accident.'' They also requested PHMSA remove the word ''severity'' in both sections because severity of any accident will vary, but does not affect whether a test is conducted. In addition, the discretion that an employer has in determining not to conduct a post-accident test ''because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use'' has been part of this section for years, but that makes it no less problematic. There are no scientifically acceptable criteria by which the employer could accurately make this decision; therefore, this option should be deleted from the employer's testing decision. Section 199.105(b)(2) requires documentation only on ''why the test was not promptly administered,'' but does not cover decisions made that eliminate some employees from testing all together. In contrast, § 199.117(a)(5) only covers recordkeeping for ''decisions not to administer . . . the drug test,'' but does not cover why the employer could not accomplish the testing within 32 hours; therefore, each paragraph should add its missing part. This recommendation applies also to the alcohol section of the proposed rule, where § 199.227(a)(2(i) and (b)(4) have the same issue. The proposed definition for ''covered task'' in §§ 192.803 and 195.503 runs the risk of being confused with ''covered function'' in § 199.3; therefore, the term ''covered task,'' and its definition should be used in part 199 in lieu of ''covered function.'' In addition, they provided comments to other sections of part 199 that were not proposed in this rulemaking action.

Thomas Lael Services commented that the documentation that describes why the decision not to test an individual relative to a reportable accident/incident should be kept for as long as the complete event records is kept.

The Advisory Committees recommended deleting language from § 199.105(b), ''. . . or because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use.''

3. PHMSA Response

Contrary to several commenters, this rulemaking does not establish new requirements for post-accident drug and alcohol testing. Those requirements currently exist in 49 CFR part 199. This rulemaking would modify the conditions under which an operator may decide not to test covered employees and establish a recordkeeping requirement for these decisions. Operators have been required to decide whether to post-accident test covered employees since part 199 was promulgated. Each accident is unique. PHMSA can neither state affirmatively which employees must be tested nor create a template for making the decision about post-accident testing.

An individual could ''contribute'' to an accident by causing it or by making the consequences more severe. The overall severity of the accident is irrelevant to the post-accident testing decision. The relevant question for severity is whether an employee's performance of a covered function affected the severity of the accident.

In PHMSA's proposed § 199.105(b)(2), operators would cease attempts to administer a drug test 32 hours after the accident. PHMSA concurs that ''or because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use'' should be removed from PHMSA's proposed 199.105(b)(1) and, therefore, the statement is removed.

The new post-accident recordkeeping requirements merely specify the type of records and length of retention. Details about what must be in the records are contained in other sections of the regulations. The post-accident testing sections of the regulations clarify the contents of the records on decisions not to administer post-accident tests.

Covered task is defined in parts 192 and 195. ''Covered function'' is defined in part 199 and has a meaning different from ''covered task.'' PHMSA used the term ''covered function'' appropriately in the NPRM.

Since PHMSA has not established record retention criteria for accidents, the drug and alcohol testing regulations must establish the retention period for decisions not to administer post-accident tests.

The Advisory Committees agreed with PHMSA's responses to the public comments.

I. Information Made Available to the Public and Request for Protection of Confidential Commercial Information

1. PHMSA's Proposal

When information is submitted to PHMSA during a rulemaking proceeding, as part of an application for a special permit, or for any other reason, PHMSA may make that information publicly available. PHMSA does not currently set out in the pipeline safety regulations the steps for requesting protection of confidential commercial information. PHMSA has set out such a procedure in its hazardous materials safety regulations. Therefore, to inform the public of how to request protection of confidential business information submitted to the Office of Pipeline Safety and to provide information regarding PHMSA's decision, PHMSA is including the procedure in the pipeline regulations. If PHMSA were to receive a request for information marked as confidential or identifies a need to make the information publicly available, PHMSA will conduct a review of the information under the standards set forth in the Freedom of Information Act (FOIA), 5 U.S.C. 552.

2. Summary of Public Comment

The Pipeline Safety Trust asked that PHMSA include in § 190.343(b) the criteria by which PHMSA will make the decision about whether the information requested to be confidential will be removed from public availability and make clear whether that decision is an appealable administrative order.

The American Gas Association (AGA) commented that it supported a clear path for operators to request confidentiality for submitted information, but indicated concern about PHMSA using its own judgment on when to keep that information confidential. AGA also suggested that operators should have an opportunity to classify their information related to special permits and thus their system as Sensitive Security Information.

The American Petroleum Institute (API) and the Association of Oil Pipe Lines (AOPL) commented that they did not oppose the proposal, but requested that certain clarifications be made including who would be responsible for making determinations concerning requests for confidentiality, confirmation that information will be treated as confidential if the requirements in proposed § 190.343(a) are followed and that the information would be disclosed only after a determination is made in accordance with § 190.343(3)(b). API and AOPL also requested that at minimum, operators are granted five business days from the date of receipt of a written notice before the information is publicly disclosed to object, and requested an opportunity for appeal within the agency (*e.g.,* to the Administrator or Chief Counsel).

Energy Transfer Partners commented that some materials required to be submitted to PHMSA may contain confidential information regarding the operator's markets, plans, anticipated customers, suppliers, vendors, contractors, etc. and commented that the proposed language was not particularly reassuring that confidentiality would be maintained. Energy Transfer Partners also commented that PHMSA should include the operator in the decision-making process regarding whether to disclose such information.

Enterprise Products Partners LP commented that industry has long relied on FOIA exemptions, established rules for treatment of confidential business information and judicially recognized privileges and that the rule should clarify that all such protections are retained. In addition, Enterprise Products Partners requested that PHMSA clarify that it will not post information submitted as confidential business information, FOIA exempt or privileged on its public Web site without prior notice to the submitter, allow a submitter ''at least 5 business days to substantiate a request for disclosure of information submitted as CBI, FOIA exempt or privileged, and include an expedited appeal process.''

FlexSteel commented that it strongly objects to the proposal, stating that confidential information is information that is intended to be private or secret and may be covered by patents or patents pending. FlexSteel stated that often the type of supporting documentation filed with certain project requests contain patented and confidential technological information because it is unique in nature. FlexSteel requested that proposed provision § 190.343 be removed.

Gas Processors Association (GPA) commented that it strongly objects to the proposal in § 190.343. GPA stated that pipelines are considered critical infrastructure and that virtually every aspect of their operations could be deemed sensitive. GPA requested that the proposed language in § 190.343 be removed from the final adopted rule so that it can be strengthened to provide the greatest amount of protections possible for sensitive information.

Northeast Gas Association stated that it supports the AGA's recommendation that PHMSA provide operators the option of utilizing the Protected Critical Infrastructure Information protection protocol under the Critical Infrastructure Information Act of 2002 for voluntarily submitted sensitive data.

Texas Pipeline Association (TPA) commented that more robust mechanisms for protection from disclosure than what is contained in the proposal are needed to protect Sensitive Security Information or Protected Critical Infrastructure Information. TPA recommended that the proposal in § 190.343 be removed from any final rule adoption and that procedures for protection of sensitive and confidential information be developed in a separate rulemaking.

3. PHMSA Response

With this new section, PHMSA is informing submitters of steps to follow if they wish to request protection for confidential commercial information submitted to PHMSA. This section also includes a provision regarding PHMSA's decision. After reviewing the comments received to the proposal, PHMSA has made some revisions to the title and regulatory text in § 190.343(a) and (b) for clarification.

In addition to concerns about the protection of confidential business information, several commenters raised concerns about submitting information that is sensitive for security reasons. PHMSA's intent with § 190.343 was to set out the steps for requesting protection of confidential commercial information. Therefore, in the final rule, PHMSA is revising the title of § 190.343 and regulatory text in subparagraph (a) to clarify that this section applies to the protection of confidential commercial information.

PHMSA's review and determinations regarding protection of security information involve a different process that is not the subject of this rulemaking. Prior to disclosure of information, PHMSA reviews the records to determine whether information is protected for security reasons and applies all applicable FOIA exemptions and Federal laws. The Department of Transportation and Department of Homeland Security (DHS) have procedures in place to protect information that is determined to be Sensitive Security Information (SSI). PHMSA's Office of Pipeline Safety Emergency Support and Security Division consults with Departmental and DHS/TSA security offices as necessary.

The steps set forth in § 190.343(a) serve to notify PHMSA that a submitter believes information to be confidential commercial information and ensures that PHMSA will protect the information as confidential commercial information until it conducts a release determination. Generally, such a decision will occur when PHMSA receives a FOIA request for the information and completes an analysis under FOIA, following the procedures in the Department's FOIA regulations in 49 CFR part 7. In an instance where there is not a FOIA request, but PHMSA identifies a need to make particular information available to the public to support its mission to protect people and the environment from the risks of gas, liquefied natural gas, and hazardous liquids or carbon dioxide transportation by pipeline, PHMSA will use the criteria set out in FOIA to analyze whether the information is protected by one or more of the FOIA exemptions.

Therefore, to address comments, PHMSA revised the regulatory text in § 190.343(b) to clarify that PHMSA will use the criteria set forth in FOIA if a release determination is necessary. This includes complying with the Department's FOIA regulations in 49 CFR 7.29 that require consultation with the submitter of information designated as confidential commercial information and written notification to the submitter of an intended disclosure of the information.

The procedures in § 190.343 require that at the time of submission, the submitter provide PHMSA with an explanation of why the information is confidential. Therefore, this section gives submitters an opportunity both at the time the information is submitted to PHMSA to provide an explanation of why the information is confidential commercial information and during the consultation process that PHMSA initiates if it has received a FOIA request or determined that there is a need to make the information publicly available.

In response to comments, we are also clarifying in the final rule that if after reviewing the submitter's request and explanations submitted after the consultation, PHMSA decides to disclose the information over the submitter's objections, PHMSA will provide written notification to the submitter at least five business days prior to the intended disclosure date.

As PHMSA is following a similar process to that under the Departmental FOIA regulations providing for submitter consultation and notification, PHMSA is not adding an appeal process for submitters of information. If a decision is made that the information is protected as confidential commercial information, a FOIA requester who has asked for the records has appeal rights under FOIA.

The Advisory Committees' recommendations also address the public comments received by PHMSA.

J. In-Service Welding

1. PHMSA's Proposal

PHMSA is revising 49 CFR 192.225, 192.227, 195.214, and 195.222 to add reference to API 1104, Appendix B.

2. Summary of Public Comment

The AGA supports PHMSA's proposal to incorporate API 1104 Appendix B as an acceptable section for the development of welding procedures and welder qualification. It does not believe that this change creates a new requirement to only use API 1104 Appendix B to qualify in service welding procedures or in service welders and, therefore, requests that PHMSA should provide clarification in the preamble language of the final rule by stating this incorporation does not create a new requirement.

Northeast Gas Association commented that it supports PHMSA's proposal to incorporate API 11 04 Appendix B as an acceptable section for the development of welding procedures and welder qualification, as long as this change provides another option along with the existing options in the regulations.

3. PHMSA Response

In the past, PHMSA has encouraged pipeline operators to develop and use welding procedures that address improvements in pipeline safety and many operators have developed in service welding procedures. Welding procedures developed to API 1104 Appendix B consider the risks associated with hydrogen in the weld metal, type of welding electrode, sleeve/fitting and carrier pipe materials, accelerated cooling, and stresses across the fillet welds. Parts 192 and 195 do not include the addition of API 1104 Appendix B as an acceptable section for the development of welding procedures and welder qualification. To allow in-service welding, PHMSA is adopting Appendix B of API 1104 into parts 192 and 195. Therefore, PHMSA is not creating new requirement but only including Appendix B into already adopted API 1104 to qualify in service welding procedures or in service welders to perform in-service welding operators must follow Appendix B of API 1104. In addition, currently, PHMSA does not allow in service welding and, therefore, there are no existing options in the regulations for in service welding.

The Advisory Committees agreed with PHMSA's responses to the public comments.

K. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDOs). In general, SDOs update and revise their published standards every 3 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995, Public Law 104–113, directs Federal agencies to use voluntary consensus standards in lieu of government-written standards whenever possible. Voluntary consensus standards are standards developed or adopted by voluntary bodies that develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, Office of Management and Budget (OMB) issued OMB Circular A–119 to implement section 12(d) of Public Law 104–113 relative to the utilization of consensus technical standards by Federal agencies. This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in Public Law 104–113.

In accordance with the preceding provisions, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporate by reference materials in 49 CFR parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 states, ''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 Web site.'' 49 U.S.C. 60102(p). On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace ''1 year'' with ''3 years'' and remove the phrases ''guidance or'' and, ''on an Internet Web site.'' This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows, ''Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue 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.''

Further, the Office of the Federal Register issued a November 7, 2014, rulemaking that revised 1 CFR 51.5 to require that agencies detail in the preamble of a rulemaking the ways the materials it incorporates by reference are reasonably available to interested parties, or how the agency worked to make those materials reasonably available to interested parties. 79 FR 66278. In relation to this rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been incorporation by reference. The SDOs agreed to make viewable copies of the incorporated standards available to the public at no cost. Pipeline operators interested in purchasing these standards can contact the standards organization. The contact information is provided in this rulemaking action, *see* § 195.3.

V. Regulatory Analyses and Notices

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

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

Executive Order 12866, as supplemented by Executive Order 13563, 76 FR 3821, requires agencies regulate in the most cost-effective manner, make a reasoned determination that the benefits of the intended regulation justify its costs, and develop regulations that impose the least burden on society. In this rule, PHMSA is amending the pipeline safety regulations to:

- Add a specific time frame for telephonic or electronic notifications of accidents and incidents;
- Establish PHMSA's cost recovery procedures for new projects that cost over $2,500,000,000 or use new and novel technologies;
- Address the NTSB's recommendations to clarify training requirements for control room team members;
- Add provisions for the renewal of expiring special permits;
- Exclude farm taps from the requirements of the DIMP requirements while adding safety requirements for the farm taps;
- Require pipeline operators to report to PHMSA for permanent reversal of flow that lasts more than 30 days or to a change in product;
- Provide methods for assessment tools by incorporating consensus standards by reference in part 195 for ILI and SCCDA (also addresses part of NTSB recommendation);
- Require electronic reporting of drug and alcohol testing results in part 199;
- Modify the criteria used to make decisions about conducting post-accident drug and alcohol tests and require operators to keep for at least three years a record of the reason why post-accident drug and alcohol test was not conducted (also addresses NTSB recommendation);
- Include the procedure for requesting protection of confidential commercial information submitted to PHMSA.
- Add reference to Appendix B of API 1104 related to in-service welding in Parts 192 and 195; and
- Make minor editorial corrections.

The regulatory impact analysis found, in summary, that annual compliance costs would be approximately $0.6 million, less savings to be realized from the removal of farm taps from the Distribution Integrity Management Program (DIMP) requirements.

Annual benefits could not be quantified as readily due to data limitations and the very minor nature of many of the changes. PHMSA expects that the improvements and clarifications made to the regulations, including those for post-incident investigations along with other provisions, will reduce pipeline incidents and the associated consequences, including the potential to prevent a future high-consequence event, such as those that have occurred on gas transmission and hazardous liquid pipelines in the past.

Regulatory Flexibility Act

The Regulatory Flexibility Act requires an agency to review regulations to assess their impact on small entities, unless the agency determines that a rule is not expected to have a significant impact on a substantial number of small entities. 5 U.S.C. 601 *et seq.* This final rule has been developed in accordance with Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461, and DOT's procedures and policies to promote compliance with the Regulatory Flexibility Act to ensure that potential impacts of rules on small entities are properly considered.

The Initial Regulatory Flexibility Analysis found that the rule could affect a substantial number of small entities because of the market structure of the gas and hazardous liquids pipeline industry, which includes many small entities. However, these impacts would not be significant. The post-accident drug testing provision would add $74 in documentation costs per reportable incident. The other provisions would not add appreciable costs, and at least one provision (farm taps) would yield compliance cost savings.

Description of the Reasons Why Action by PHMSA Is Being Considered

PHMSA is amending the regulations to address the 2011 Act's section 9 (accident and incident reporting requirements) to within one hour so that timely actions can be taken to pipeline accidents and incidents, and section 13 (cost recovery) so that PHMSA's limited resources for enforcement and other safety activities are not used for operators design reviews. NTSB recommendations for control room training and drug and alcohol reporting requirements are addressed under this rule. A special permit renewal procedure is added so that pipeline operators have a renewal procedure to follow to renew their expiring special permits. In addition, other non-substantive changes are amended to correct language and provide methods for assessment tools as recommended by incorporating consensus standards (this addresses parts of NTSB recommendations P–12–3 and the NACE recommendations). Specifically, these amendments address: Farm tap requirements to address the NAPSR and INGAA concerns in including farm taps under the DIMP requirements; notification for reversal of flow or change in product for more than 60 days so that PHMSA is aware of the transported product; incorporation by reference of standards to address ILI and SCCDA; and additional testing of drug and alcohol tests, electronic reporting of drug and alcohol testing results, modifying the criteria used to make decisions about conducting post-accident drug and alcohol tests and post-accident drug and alcohol testing recordkeeping to address a NTSB recommendation; the process to request confidential treatment of submitted information similar to the process currently set out in 49 CFR 105.30 of the Hazardous Materials Regulations; and, editorial amendments to correct some errors or outdated deadlines.

Succinct Statement of the Objectives of, and Legal Basis for, This Rule

Under the Federal 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 this authority to the PHMSA Administrator. 49 CFR 1.97(a). This rulemaking action will create changes in the regulations consistent with the protection of persons and property while changing unduly burdensome or nonsensical requirements.

Description of Small Entities to Which This Rulemaking Action Will Apply

The initial Regulatory Flexibility Analysis found that the rule could affect a substantial number of small entities because of the market structure of the gas and hazardous liquids pipeline industry, which includes many small entities. However, these impacts would not be significant. The provision to document the reason for not drug testing post-accident adds $74 in documentation costs per reportable incident. The other provisions would not add appreciable costs, and at least one provision (Farm Taps) would yield compliance cost savings, though those savings are minimal.

Description of Any Significant Alternatives to This Rule That Accomplish the Stated Objectives of Applicable Statutes and That Minimize Any Significant Economic Impact of the 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.

Executive Order 13175

PHMSA has analyzed this rule according to the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments,'' 65 FR 67249. The funding and consultation requirements of Executive Order 13175 do not apply because this rule does not significantly or uniquely affect the communities of Indian tribal governments or impose substantial direct compliance costs.

Paperwork Reduction Act

PHMSA has analyzed this final rule in accordance with the Paperwork Reduction Act of 1995 (PRA). Public Law 96–511. The PRA requires federal agencies to minimize paperwork burden imposed on the American public by ensuring maximum utility and quality of federal information, ensuring the use of information technology to improve government performance, and improving the federal government's accountability for managing information collection activities. Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA estimates that this rulemaking action will impact the following information collections:

''Transportation of Hazardous Liquids by Pipeline: Record keeping and Accident Reporting'' identified under Office of Management and Budget (OMB) Control Number 2137–0047; ''Incident and Annual Reports for Gas Pipeline Operators'' identified under Office of Management and Budget (OMB) Control Number 2137–0522; ''Qualification of Pipeline Safety Training'' identified under Office of Management and Budget (OMB) Control Number 2137–0600; and ''National Registry of Pipeline and LNG Operators'' identified under Office of Management and Budget (OMB) Control Number 2137–0627.

PHMSA is also creating a new information collection to cover the recordkeeping requirement for post-accident drug testing: ''Post-Accident Drug Testing for Pipeline Operators.'' PHMSA will request a new Control Number from the Office of Management and Budget (OMB) for this information collection.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements that need information collection in this proposed rule. The information collection is contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burdens are estimated to be revised as follows:

1. *Title:* Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting.

OMB Control Number: 2137–0047.

Current Expiration Date: December 31, 2016.

Abstract: This information collection covers recordkeeping and accident reporting by hazardous liquid pipeline operators who are subject to 49 CFR part 195. Section 195.50 specifies the definition of an ''accident'' and the reporting criteria for submitting a Hazardous Liquid Accident Report (form PHMSA F7000–1) is detailed in § 195.54. PHMSA is revising the form PHMSA F7000–1 and its instructions to include the concept of ''confirmed discovery'' as amended in this rule. Operators will be required to include the date and time of the confirmed discovery of a hazardous liquid pipeline accident. PHMSA does not expect this revision to increase the burden of reporting.

Affected Public: Hazardous liquid pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 847.

Total Annual Burden Hours: 52,429.

Frequency of collection: On Occasion.

2. *Title:* Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: October 31, 2017.

Abstract: This rulemaking action will result in a modification to three gas incident forms to include the concept of ''confirmed discovery'' as amended in this rule. Operators will be required to include the date and time of the confirmed discovery of a natural gas pipeline incident. PHMSA does not expect this revision to increase the burden of reporting.

Affected Public: Gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 12,164.

Total Annual Burden Hours: 92,321.

Frequency of Collection: On occasion.

3. *Title:* ''National Registry of Pipeline and LNG Operators''

OMB Control Number: 2137–0627.

Current Expiration Date: May 31, 2018.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse of data on regulated operators or those subject to reporting requirements under 49 CFR parts 192, 193, or 195. This registry incorporates the use of two forms: (1) The Operator Assignment Request Form (PHMSA F 1000.1) and, (2) the Operator Registry Notification Form (PHMSA F 1000.2). This rule amends § 191.22 to require operators to notify PHMSA upon the occurrence of the following: Construction of 10 or more miles of a new or replacement pipeline; construction of a new LNG plant or LNG facility; reversal of product flow direction when the reversal is expected to last more than 30 days; if a pipeline is converted for service under § 192.14, or has a change in commodity as reported on the annual report as required by § 191.17.

These notifications are estimated to be rare but would fall under the scope of Operator Notifications required by PHMSA as a result of this rule. PHMSA estimates that this new reporting requirement will add 10 new responses and 10 annual burden hours to the currently approved information collection.

Affected Public: Operators of PHMSA-Regulated Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 640.

Total Annual Burden Hours: 640.

Frequency of Collection: On occasion.

4. *Title:* ''Post-Accident Drug Testing for Pipeline Operators''

OMB Control Number: Will request one from OMB.

Current Expiration Date: New Collection—To be determined.

Abstract: This rule amends 49 CFR 199.227 to require operators to retain records for three years if they decide not to administer post-accident/incident drug testing on affected employees). As a result, operators who choose not to perform post-accident drug and alcohol tests on affected employees are required to keep records explaining their decision not to do so. PHMSA estimates this recordkeeping requirement will result in 609 responses and 1,218 burden hours for recordkeeping. PHMSA does not currently have an information collection which covers this requirement and will request the approval of this new collection, along with a new OMB Control Number, from the Office of Management and Budget.

Affected Public: Operators of PHMSA-Regulated Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 609.

Total Annual Burden Hours: 1,218.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Dow, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration, 2nd Floor, 1200 New Jersey Avenue SE., Washington, DC 20590–0001. Telephone: 202–366–1246.

Unfunded Mandates Reform Act of 1995

This final rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. Public Law 104–4. PHMSA has determined that the rule does not impose annual expenditures on State, local, or tribal governments of the private sector in excess of $155 million, and thus, does not require an Unfunded Mandates Act analysis.[7]

National Environmental Policy Act

The National Environmental Policy Act, 42 U.S.C. 4321 through 4375, requires that Federal agencies analyze rulemaking actions to determine whether those actions will have a significant impact on the human environment. The Council on Environmental Quality regulations, 40 CFR parts 1500–1508, require Federal agencies to conduct an environmental review considering: (1) The need for the regulatory action, (2) alternatives to the regulatory action, (3) probable environmental impacts of the regulatory action and alternatives, and (4) the agencies and persons consulted during the rulemaking development 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 action is to enhance pipeline integrity and safety to lessen the frequency and consequences of pipeline incidents that cause environmental degradation, personal injury, and loss of life.

The need for this action stems from the statutory mandates in sections 9 and 13 of the 2011 Act, NTSB recommendations, and the need to add new reference material and make non substantive edits. Section 9 of the 2011 Act directs PHMSA to require a specific time limit for telephonic or electronic reporting of pipeline accidents and incidents, and section 13 of the 2011 Act allows PHMSA to recover costs associated with pipeline design reviews. NTSB has made recommendations regarding the clarification of OQ requirements in control rooms, and to eliminate operator discretion with regard to post-accident drug and alcohol

[7] The Unfunded Mandates Act threshold was $100 million in 1995. Using the non-seasonally adjusted CPI–U (Index series CUUR000SA0), that number is $155 million in 2014 dollars.

testing of covered employees. In addition, PHMSA's safety regulations require periodic updates and clarifications to enhance compliance and overall safety.

2. Alternatives

In developing this rulemaking action, PHMSA considered two alternatives:

(1) No action, or

(2) Amend revisions to the pipeline safety regulations to incorporate the amendments as described in this document.

Alternative 1: PHMSA has an obligation to ensure the safe and effective transportation of hazardous liquids and gases by pipeline. The changes in this rulemaking action serve that purpose by clarifying the pipeline safety regulations and addressing Congressional mandates and NTSB safety recommendations. A failure to undertake these actions would be non-responsive to the Congressional mandates and the NTSB recommendations. Accordingly, PHMSA rejected the ''no action'' alternative.

Alternative 2: PHMSA is making certain amendments and non-substantive changes to the pipeline safety regulations to add a specific time frame for telephonic or electronic notifications of accidents and incidents and add provisions for cost recovery for design reviews of certain new projects, for the renewal of expiring special permits, and to request PHMSA keep submitted information confidential. PHMSA is also making changes to the drug and alcohol testing requirements, control room team training requirements, and is providing methods for assessment tools by incorporating consensus standards by reference for ILI and SCCDA.

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 2.6 million miles of pipelines 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 environments potentially affected by this rule includes the 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 habitats, forests, grasslands, offshore marine ecosystems), and special ecological resources (*e.g.,* threatened and endangered plant and animal species and their habitats, 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 this rule contain hazardous materials, resources within the physically affected environments, as well as public health and safety, may be affected by 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 impacts could vary from property damage and environmental damage to injuries or, on rare occasions, fatalities.

The amendments are improvements to the existing pipeline safety requirements and would have little or no impact on the human environment. On a national scale, the cumulative environmental damage from pipelines would most likely be reduced slightly.

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

Preparers: This Environmental Assessment was prepared by DOT staff from PHMSA and Volpe National Transportation Systems Center (Office of the Secretary for Research and Technology (OST–R)).

4. Finding of No Significant Impact

PHMSA has determined that the selected alternative would have a positive, non-significant, impact on the human environment.

Executive Order 13132

PHMSA has analyzed this rule according to Executive Order 13132, ''Federalism,'' 64 FR 43255. The 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 rule does not impose substantial direct compliance costs on State and local governments. This 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 rule is not a ''significant energy action'' under Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use,'' 66 FR 28355. 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 rule as a significant energy action.

Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in spring and fall of each year. The RIN contained in the heading of this document can be used to cross-reference this action with the United Agenda.

List of Subjects

49 CFR Part 190

Administrative practice and procedure, Penalties, Cost recovery, Special permits.

49 CFR Part 191

Incident, Pipeline safety, Reporting and recordkeeping requirements, Reversal of flow.

49 CFR Part 192

Control room, Distribution integrity management program, Gathering lines, Incorporation by reference, Operator qualification, Pipeline safety, Safety devices, Security measures.

49 CFR Part 195

Ammonia, Carbon dioxide, Control room, Corrosion control, Direct and indirect costs, Gathering lines, Incident, Incorporation by reference, Operator qualification, Petroleum, Pipeline safety, Reporting and recordkeeping requirements, Reversal of flow, and Safety devices.

49 CFR Part 199

Alcohol testing, Drug testing, Pipeline safety, Reporting and recordkeeping requirements, Safety, and Transportation.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 190, 191, 192, 195, and 199 as follows:

PART 190—PIPELINE SAFETY ENFORCEMENT AND REGULATORY PROCEDURES

■ 1. The authority citation for part 190 continues to read as follows:

Authority: 33 U.S.C. 1321(b); 49 U.S.C. 60101 *et seq.;* 49 CFR 1.97.

■ 2. In § 190.3, add the definition ''New and novel technologies'' in alphabetical order to read as follows:

§ 190.3 Definitions.

* * * * *

New and novel technologies means any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in 49 CFR parts 192, 193, or 195, due to technology or design advances and innovation for new construction. Technologies that are addressed in consensus standards that are incorporated by reference into parts 192, 193, and 195 are not ''new or novel technologies.''

* * * * *

■ 3. Amend § 190.341 by:

■ a. Revising paragraph (c)(8) and removing paragraph (c)(9) and revising paragraph (d);

■ b. Re-designating paragraphs (e) through (j) as paragraphs (g) through (l) and adding new paragraphs (e) and (f).

The additions and revisions read as follows:

§ 190.341 Special permits.

* * * * *

(c) * * *

(8) Any other information PHMSA may need to process the application including environmental analysis where necessary.

(d) *How does PHMSA handle special permit applications?*—(1) *Public notice.* Upon receipt of an application or renewal of a special permit, PHMSA will provide notice to the public of its intent to consider the application and invite comment. In addition, PHMSA may consult with other Federal agencies before granting or denying an application or renewal on matters that PHMSA believes may have significance for proceedings under their areas of responsibility.

(2) *Grants, renewals, and denials.* If the Associate Administrator determines that the application complies with the requirements of this section and that the waiver of the relevant regulation or standard is not inconsistent with pipeline safety, the Associate Administrator may grant the application, in whole or in part, for a period of time from the date granted. Conditions may be imposed on the grant if the Associate Administrator concludes they are necessary to assure safety, environmental protection, or are otherwise in the public interest. If the Associate Administrator determines that the application does not comply with the requirements of this section or that a waiver is not justified, the application will be denied. Whenever the Associate Administrator grants or denies an application, notice of the decision will be provided to the applicant. PHMSA will post all special permits on its Web site at *http://www.phmsa.dot.gov/.*

(e) *How does PHMSA handle special permit renewals?* (1) The grantee of the special permit must apply for a renewal of the permit 180 days prior to the permit expiration.

(2) If, at least 180 days before an existing special permit expires the holder files an application for renewal that is complete and conforms to the requirements of this section, the special permit will not expire until final administrative action on the application for renewal has been taken:

(i) Direct fax to PHMSA at: 202–366–4566; or

(ii) Express mail, or overnight courier to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590.

(f) *What information must be included in the renewal application?* (1) The renewal application must include a copy of the original special permit, the docket number on the special permit, and the following information as applicable:

(i) A summary report in accordance with the requirements of the original special permit including verification that the grantee's operations and maintenance plan (O&M Plan) is consistent with the conditions of the special permit;

(ii) Name, mailing address and telephone number of the special permit grantee;

(iii) Location of special permit—areas on the pipeline where the special permit is applicable including: Diameter, mile posts, county, and state;

(iv) Applicable usage of the special permit—original and future; and

(v) Data for the special permit segment and area identified in the special permit as needing additional inspections to include, as applicable:

(A) Pipe attributes: Pipe diameter, wall thickness, grade, seam type; and pipe coating including girth weld coating;

(B) Operating Pressure: Maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography);

(C) High Consequence Areas (HCAs): HCA boundaries on aerial photography;

(D) Material Properties: Pipeline material documentation for all pipe, fittings, flanges, and any other facilities included in the special permit. Material documentation must include: Yield strength, tensile strength, chemical composition, wall thickness, and seam type;

(E) Test Pressure: Hydrostatic test pressure and date including pressure and temperature charts and logs and any known test failures or leaks;

(F) In-line inspection (ILI): Summary of ILI survey results from all ILI tools used on the special permit segments during the previous five years or latest ILI survey result;

(G) Integrity Data and Integration: The following information, as applicable, for the past five (5) years: Hydrostatic test pressure including any known test failures or leaks; casings(any shorts); any in-service ruptures or leaks; close interval survey (CIS) surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current/direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC), selective seam weld corrosion (SSWC) and hard spot excavations and findings; and pipe exposures from encroachments;

(H) In-service: Any in-service ruptures or leaks including repair type and failure investigation findings; and

(I) Aerial Photography: Special permit segment and special permit inspection area, if applicable.

(2) PHMSA may request additional operational, integrity or environmental assessment information prior to granting any request for special permit renewal.

(3) The existing special permit will remain in effect until PHMSA acts on the application for renewal by granting or denying the request.

* * * * *

■ 4. Section 190.343 is added to subpart D read as follows:

§ 190.343 Information made available to the public and request for protection of confidential commercial information.

When you submit information to PHMSA during a rulemaking proceeding, as part of your application for special permit or renewal, or for any other reason, we may make that information publicly available unless you ask that we keep the information confidential.

(a) *Asking for protection of confidential commercial information.* You may ask us to give confidential treatment to information you give to the agency by taking the following steps:

(1) Mark ''confidential'' on each page of the original document you would like to keep confidential.

(2) Send us, along with the original document, a second copy of the original document with the confidential commercial information deleted.

(3) Explain why the information you are submitting is confidential commercial information.

(b) *PHMSA decision.* PHMSA will treat as confidential the information that you submitted in accordance with this section, unless we notify you otherwise. If PHMSA decides to disclose the information, PHMSA will review your request to protect confidential commercial information under the criteria set forth in the Freedom of Information Act (FOIA), 5 U.S.C. 552, including following the consultation procedures set out in the Departmental FOIA regulations, 49 CFR 7.29. If PHMSA decides to disclose the information over your objections, we will notify you in writing at least five business days before the intended disclosure date.

■ 5. In part 190, subpart E is added to read as follows:

Subpart E—Cost Recovery for Design Reviews

§ 190.401 Scope.

If PHMSA conducts a facility design and/or construction safety review or inspection in connection with a proposal to construct, expand, or operate a gas, hazardous liquid or carbon dioxide pipeline facility, or a liquefied natural gas facility that meets the applicability requirements in § 190.403, PHMSA may require the applicant proposing the project to pay the costs incurred by PHMSA relating to such review, including the cost of design and construction safety reviews or inspections.

§ 190.403 Applicability.

The following paragraph specifies which projects will be subject to the cost recovery requirements of this section.

(a) This section applies to any project that—

(1) Has design and construction costs totaling at least $2,500,000,000, as periodically adjusted by PHMSA, to take into account increases in the Consumer Price Index for all urban consumers published by the Department of Labor, based on—

(i) The cost estimate provided to the Federal Energy Regulatory Commission in an application for a certificate of public convenience and necessity for a gas pipeline facility or an application for authorization for a liquefied natural gas pipeline facility; or

(ii) A good faith estimate developed by the applicant proposing a hazardous liquid or carbon dioxide pipeline facility and submitted to the Associate Administrator. The good faith estimate for design and construction costs must include all of the applicable cost items contained in the Federal Energy Regulatory Commission application referenced in § 190.403(a)(1)(i) for a gas or LNG facility. In addition, an applicant must take into account all survey, design, material, permitting, right-of way acquisition, construction, testing, commissioning, start-up, construction financing, environmental protection, inspection, material transportation, sales tax, project contingency, and all other applicable costs, including all segments, facilities, and multi-year phases of the project;

(2) Uses new or novel technologies or design, as defined in § 190.3.

(b) The Associate Administrator may not collect design safety review fees under this section and 49 U.S.C. 60301 for the same design safety review.

(c) The Associate Administrator, after receipt of the design specifications, construction plans and procedures, and related materials, determines if cost recovery is necessary. The Associate Administrator's determination is based on the amount of PHMSA resources needed to ensure safety and environmental protection.

§ 190.405 Notification.

For any new pipeline facility construction project in which PHMSA will conduct a design review, the applicant proposing the project must notify PHMSA and provide the design specifications, construction plans and procedures, project schedule and related materials at least 120 days prior to the commencement of any of the following activities: Route surveys for construction, material manufacturing, offsite facility fabrications, construction equipment move-in activities, onsite or offsite fabrications, personnel support facility construction, and any offsite or onsite facility construction. To the maximum extent practicable, but not later than 90 days after receiving such design specifications, construction plans and procedures, and related materials, PHMSA will provide written comments, feedback, and guidance on the project.

§ 190.407 Master Agreement.

PHMSA and the applicant will enter into an agreement within 60 days after PHMSA received notification from the applicant provided in § 190.405, outlining PHMSA's recovery of the costs associated with the facility design safety review.

(a) A Master Agreement, at a minimum, includes:

(1) Itemized list of direct costs to be recovered by PHMSA;

(2) Scope of work for conducting the facility design safety review and an estimated total cost;

(3) Description of the method of periodic billing, payment, and auditing of cost recovery fees;

(4) Minimum account balance which the applicant must maintain with PHMSA at all times;

(5) Provisions for reconciling differences between total amount billed and the final cost of the design review, including provisions for returning any excess payments to the applicant at the conclusion of the project;

(6) A principal point of contact for both PHMSA and the applicant; and

(7) Provisions for terminating the agreement.

(8) A project reimbursement cost schedule based upon the project timing and scope.

(b) [Reserved]

§ 190.409 Fee structure.

The fee charged is based on the direct costs that PHMSA incurs in conducting the facility design safety review (including construction review and inspections), and will be based only on costs necessary for conducting the facility design safety review. ''Necessary for'' means that but for the facility design safety review, the costs would not have been incurred and that the costs cover only those activities and items without which the facility design safety review cannot be completed.

(a) Costs qualifying for cost recovery include, but are not limited to—

(1) Personnel costs based upon total cost to PHMSA;

(2) Travel, lodging and subsistence;

(3) Vehicle mileage;

(4) Other direct services, materials and supplies;

(5) Other direct costs as may be specified in the Master Agreement.

(b) [Reserved]

§ 190.411 Procedures for billing and payment of fee.

All PHMSA cost calculations for billing purposes are determined from the best available PHMSA records.

(a) PHMSA bills an applicant for cost recovery fees as specified in the Master Agreement, but the applicant will not be billed more frequently than quarterly.

(1) PHMSA will itemize cost recovery bills in sufficient detail to allow independent verification of calculations.

(2) [Reserved]

(b) PHMSA will monitor the applicant's account balance. Should the account balance fall below the required minimum balance specified in the Master Agreement, PHMSA may request at any time the applicant submit payment within 30 days to maintain the minimum balance.

(c) PHMSA will provide an updated estimate of costs to the applicant on or near October 1st of each calendar year.

(d) Payment of cost recovery fees is due within 30 days of issuance of a bill for the fees. If payment is not made within 30 days, PHMSA may charge an annual rate of interest (as set by the Department of Treasury's Statutory Debt Collection Authorities) on any outstanding debt, as specified in the Master Agreement.

(e) Payment of the cost recovery fee by the applicant does not obligate or prevent PHMSA from taking any particular action during safety inspections on the project.

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

■ 6. 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 60141; and 49 CFR 1.97.

■ 7. In § 191.3, add the definition ''Confirmed Discovery'' in alphabetical order to read as follows:

§ 191.3 Definitions.

* * * * *

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

* * * * *

■ 8. In § 191.5, paragraph (a) is revised and paragraph (c) is added to read as follows:

§ 191.5 Immediate notice of certain incidents.

(a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) of this section of each incident as defined in § 191.3.

* * * * *

(c) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

■ 9. In § 191.22, paragraph (c)(1)(ii) is revised and paragraphs (c)(1)(v) and (c)(1)(vi) are added to read as follows:

§ 191.22 National Registry of Pipeline and LNG operators

* * * * *

(c) * * *

(1) * * *

(ii) Construction of 10 or more miles of a new or replacement pipeline;

* * * * *

(v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

(vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

* * * * *

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

■ 10. 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, 60118, 60137, 60141; and 49 CFR 1.97.

■ 11. In § 192.14, paragraph (c) is added to read as follows

§ 192.14 Conversion to service subject to this part.

* * * * *

(c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.

■ 12. In Section 192.175, paragraph (b) is revised to read as follows:

§ 192.175 Pipe-type and bottle-type holders.

* * * * *

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

C = (3D*P*F)/1000) in inches; (C = (3D*P*F*)/6,895) in millimeters

in which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).
D = Outside diameter of pipe containers or bottles in inches (millimeters).
P = Maximum allowable operating pressure, psi (kPa) gauge.
F = Design factor as set forth in § 192.111 of this part.

■ 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, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 192.7) to produce welds meeting 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 applicable welding standard(s).

* * * * *

■ 14. In § 192.227, paragraph (a) is revised to read as follows:

§ 192.227 Qualification of welders.

(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, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 192.7). However, a welder or welding operator qualified under an earlier edition than the listed in § 192.7 of this part may weld but may not requalify under that earlier edition.

* * * * *

■ 15. In § 192.631, paragraphs (b)(3) and (4) are revised, paragraph (b)(5) is added, paragraphs (h)(4) and (5) are revised, and paragraph (h)(6) is added to read as follows:

§ 192.631 Control room management.

* * * * *

(b) * * *

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

* * * * *

(h) * * *

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

(6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

* * * * *

■ 16. Section 192.740 is added to read as follows:

§ 192.740 Pressure regulating, limiting, and overpressure protection—Individual service lines directly connected to production, gathering, or transmission pipelines.

(a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

(b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(c) This section does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

■ 17. Section 192.1003 is revised to read as follows:

§ 192.1003 What do the regulations in this subpart cover?

(a) *General.* Unless exempted in paragraph (b) of this section this subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005 through 192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in § 192.1015 of this subpart.

(b) *Exceptions.* This subpart does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 18. The authority citation for part 195 continues to read as follows:

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

■ 19. In § 195.2, add the definitions ''Confirmed discovery,'' ''In-Line Inspection (ILI),'' ''In-Line Inspection Tool or Instrumented Internal Inspection Device,'' and ''Significant stress corrosion cracking'' in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

* * * * *

In-Line Inspection (ILI) means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool. Also called *intelligent* or *smart pigging.*

In-Line Inspection Tool or *Instrumented Internal Inspection Device* means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside. Also known as *intelligent* or *smart pig.*

* * * * *

Significant Stress Corrosion Cracking means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.

* * * * *

■ 20. In § 195.3:

■ a. Add paragraph (b)(23);

■ b. Revise paragraph (c)(2);

■ c. Redesignate paragraphs (d) through (h) as (e) through (i) respectively and add a new paragraph (d); and

■ d. Amend newly redesignated paragraph (g) by adding paragraphs (g)(3) and (4); and

■ e. Revise newly redesignated paragraph (i)(1).

The additions and revisions read as follows:

§ 195.3 Incorporation by reference.

* * * * *

(b) * * *

(23) API Standard 1163, ''In-Line Inspection Systems Qualification'' Second edition, April 2013, (API Std 1163), IBR approved for § 195.591.

* * * * *

(c) * * *

(2) ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, (ASME/ANSI B31G), IBR approved for §§ 195.452(h); 195.587; and 195.588(c).

* * * * *

(d) American Society for Nondestructive Testing, P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228. *https://asnt.org.*

(1) ANSI/ASNT ILI–PQ–2005(2010), ''In-line Inspection Personnel Qualification and Certification'' reapproved October 11, 2010, (ANSI/ASNT ILI–PQ), IBR approved for § 195.591.

(2) [Reserved]

* * * * *

(g) * * *

(3) NACE SP0102–2010, ''Standard Practice, Inline Inspection of Pipelines'' revised March 13, 2010, (NACE SP0102), IBR approved for § 195.591.

(4) NACE SP0204–2008, ''Standard Practice, Stress Corrosion Cracking (SSC) Direct Assessment Methodology'' reaffirmed September 18, 2008, (NACE SP0204), IBR approved for § 195.588(c).

* * * * *

(i) * * *

(1) AGA Pipeline Research Committee, Project PR–3–805 ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' December 22, 1989, (PR–3–805 (RSTRING)). IBR approved for §§ 195.452(h); 195.587; and 195.588(c).

* * * * *

■ 21. In § 195.5, paragraph (d) is added to read as follows:

§ 195.5 Conversion to service subject to this part.

* * * * *

(d) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 195.64.

■ 22. In § 195.52, paragraph (a) introductory text and paragraph (d) are revised to read as follows:

§ 195.52 Immediate notice of certain accidents.

(a) *Notice requirements.* At the earliest practicable moment following discovery, of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, but no later than one hour after confirmed discovery, the operator of the system must give notice, in accordance with paragraph (b) of this section of any failure that:

* * * * *

(d) *New information.* Within 48 hours after the confirmed discovery of an accident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with a revised estimate of the amount of product released, location of the failure, time of the failure, a revised estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the accident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

§ 195.64 [Amended]

■ 23. In § 195.64, in paragraph (a), the term ''hazardous liquid'' is removed and replaced with the term ''hazardous liquid or carbon dioxide'' in the first sentence.

■ 24. In § 195.64, paragraph (c)(1)(ii) is revised and paragraphs (c)(1)(iii) and (iv) are added to read as follows:

§ 195.64 National Registry of Pipeline and LNG operators

* * * * *

(c) * * *

(1) * * *

(ii) Construction of 10 or more miles of a new or replacement hazardous liquid or carbon dioxide pipeline;

(iii) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

(iv) A pipeline converted for service under § 195.5, or a change in commodity as reported on the annual report as required by § 195.49.

* * * * *

■ 25. In § 195.120, the section heading and paragraph (a) are revised to read as follows:

§ 195.120 Passage of In-Line Inspection tools.

(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each replacement of line pipe, valve, fitting, or other line component in a pipeline must be designed and constructed to accommodate the passage of an In-Line Inspection tool, in accordance with NACE SP0102–2010, Section 7 (incorporated by reference, *see* § 195.3).

* * * * *

■ 26. 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, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 195.3), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 195.3). The quality of the test welds used to qualify the welding procedures must be determined by destructive testing.

* * * * *

■ 27. In § 195.222, paragraph (a) is 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, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 195.3), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC), (incorporated by reference, *see* § 195.3) except that a welder or welding operator qualified under an earlier edition than listed in § 195.3, may weld but may not requalify under that earlier edition.

* * * * *

§ 195.248 [Amended]

■ 28. In § 195.248, the phrase ''100 feet (30 millimeters)'' is removed and ''100 feet (30.5 meters)'' is added in its place in the table to paragraph (a).

■ 29. In § 195.446, revise paragraphs (b)(3) and (4), add paragraph (b)(5), revise paragraphs (h)(4) and (5), and add paragraph (h)(6) to read as follows:

§ 195.446 Control room management.

* * * * *

(b) * * *

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers.

* * * * *

(h) * * *

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

(6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph no later than January 23, 2018.

* * * * *

■ 30. In § 195.452, paragraph (a)(4) is added and paragraphs (c)(1)(i)(A) and (j)(5)(i) are revised to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) * * *

(4) Low stress pipelines as specified in § 195.12.

* * * * *

(c) * * *

(1) * * *

(i) * * *

(A) In-Line Inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges, and grooves. For pipeline segments that are susceptible to cracks (pipe body and weld seams), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an In-Line Inspection Tool, an operator must comply with § 195.591;

* * * * *

(j) * * *

(5) * * *

(i) In-Line Inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges, and grooves. For pipeline segments that are susceptible to cracks (pipe body and weld seams), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. When performing an assessment using an In-Line Inspection tool, an operator must comply with § 195.591;

* * * * *

■ 31. In § 195.588, paragraph (a) is revised and paragraph (c) is added to read as follows:

§ 195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion or stress corrosion cracking, you must follow the requirements of this section. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

* * * * *

(c) If you use direct assessment on an onshore pipeline to evaluate the effects of stress corrosion cracking, you must develop and follow a Stress Corrosion Cracking Direct Assessment plan that meets all requirements and recommendations of NACE SP0204–2008 (incorporated by reference, *see* § 195.3) and that implements all four steps of the Stress Corrosion Cracking Direct Assessment process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204–2008, Section 1.1.7, Stress Corrosion Cracking Direct Assessment is complementary with other inspection methods such as in-line inspection or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data to identify whether the conditions for stress corrosion cracking are present and to prioritize the segments for assessment in accordance with NACE SP0204–2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204–2008 indicate the potential for Stress Corrosion Cracking Direct Assessment. This data gathering process must be conducted in accordance with NACE SP0204–2008, Section 5.3, and must include, at a minimum, all data listed in NACE SP0204–2008, Table 2. Further, an operator must analyze the following factors as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, factors that affect the rate of carbon dioxide generation, and/or cathodic protection.

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied cathodic protection such as overprotection, cathodic protection loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield cathodic protection when disbonded from the pipe.

(v) Other factors that affect the mechanistic properties associated with SCC including but not limited to operating pressures, high tensile residual stresses, and the presence of sulfides.

(2) *Indirect inspection.* In addition to the requirements and recommendations of NACE SP0204–2008, Section 4, the plan's procedures for indirect inspection must include provisions for conducting at least two different, but complementary, indirect assessment electrical surveys, and the basis on the selections as the most appropriate for the pipeline segment based on the data gathering and integration step.

(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204–2008, Section 5, the plan's procedures for direct examination must provide for conducting a minimum of four direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Non-significant SCC, as defined by NACE SP0204–2008, may be mitigated by either hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG (incorporated by reference, *see* § 195.3) and must be sufficient to meet the design requirements of subpart C of this part.

(ii) Significant SCC must be mitigated using a hydrostatic testing program with a minimum test pressure between 100% up to 110% of the specified minimum yield strength for a 30-minute spike test immediately followed by a pressure test in accordance with subpart E of this part. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with subpart E of this part. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment retested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (c)(4)(i) of this section.

(5) *Post assessment.* In addition to the requirements and recommendations of NACE SP0204–2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of Stress Corrosion Cracking Direct Assessment, the plan's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to Stress Corrosion Cracking as well as on the behavior mechanism of identified cracking. Factors to be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204–2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of cathodic protection that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions;

(v) Cyclic loading conditions;

(vi) Conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

■ 32. Section 195.591 is added to read as follows:

§ 195.591 In-Line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API Std 1163, *Inline Inspection Systems Qualification Standard;* ANSI/ASNT ILI–PQ, *Inline Inspection Personnel Qualification and Certification;* and NACE SP0102–2010, *Inline Inspection of Pipelines* (incorporated by reference, see § 195.3). An in-line inspection may also be conducted using tethered or remote control tools provided they generally comply with those sections of NACE SP0102–2010 that are applicable.

PART 199—DRUG AND ALCOHOL TESTING

■ 33. The authority citation for part 199 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60117, and 60118; 49 CFR 1.97.

■ 34. In § 199.105, paragraph (b) is revised to read as follows:

§ 199.105 Drug tests required.

* * * * *

(b) *Post-accident testing.* (1) As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

(2) If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by paragraph (b)(1) of this section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test.

* * * * *

■ 35. In § 199.117, paragraph (a)(5) is added to read as follows:

§ 199.117 Recordkeeping.

(a) * * *

(5) Records of decisions not to administer post-accident employee drug tests must be kept for at least 3 years.

* * * * *

■ 36. In § 199.119, paragraphs (a) and (b) are revised to read as follows:

§ 199.119 Reporting of anti-drug testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

(b) Each report required under this section must be submitted electronically at *http://damis.dot.gov.* An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

* * * * *

■ 37. In § 199.225, the introductory text and paragraph (a)(1) are revised to read as follows:

§ 199.225 Alcohol tests required.

Each operator must conduct the following types of alcohol tests for the presence of alcohol:

(a) * * *

(1) As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.

* * * * *

■ 38. In § 199.227, paragraph (b)(4) is added to read as follows:

§ 199.227 Retention of records.

* * * * *

(b) * * *

(4) *Three years.* Records of decisions not to administer post-accident employee alcohol tests must be kept for a minimum of three years.

* * * * *

■ 39. In § 199.229, paragraphs (a) and (c) are revised as follows:

§ 199.229 Reporting of alcohol testing results.

(a) Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

* * * * *

(c) Each report required under this section must be submitted electronically at *http://damis.dot.gov.* An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (*https://portal.phmsa.dot.gov/phmsaportallanding*). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

* * * * *

Issued in Washington, DC, on December 22, 2016, under authority delegated in 49 CFR Part 1.97.

Marie Therese Dominguez,

Administrator.

[FR Doc. 2016–31461 Filed 1–19–17; 8:45 am]

BILLING CODE 4910–60–P