DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

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

[Docket No. PHMSA–2013–0163]

RIN 2137–AE94

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

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

ACTION: Notice of proposed rulemaking.

SUMMARY: PHMSA is proposing amendments to 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 proposing 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 for submitters of information to request PHMSA keep the information confidential. We are also proposing changes to the operator qualification (OQ) requirements and drug and alcohol testing requirements and incorporating consensus standards by reference for in-line inspection (ILI) and Stress Corrosion Cracking Direct Assessment (SCCDA).

DATES: Submit comments by September 8, 2015.

ADDRESSES: Comments should reference Docket No. PHMSA–2013–0163 and may be submitted in the following ways:

- *E-Gov Web site: http://www.regulations.gov.* This Web site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Management System: U.S. Department of Transportation (DOT), Docket Operations, M–30, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001.
- *Hand Delivery:* DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001 between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays.

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

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

Privacy Act Statement

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

FOR FURTHER INFORMATION CONTACT: Tewabe Asebe by telephone at 202–366–5523 or by email at *Tewabe.Asebe@dot.gov.*

SUPPLEMENTARY INFORMATION:

Executive Summary

A. Purpose of the Regulatory Action (Statement of Need)

The purpose of this proposed 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). The proposal associated with section 9 would limit the accident and incident reporting requirements to within one hour. PHMSA expects that quicker accident and incident reporting would lead to a safety benefit to the public, the environment, and limit property damage. The proposal associated with section 13 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. PHMSA is also proposing to expand the existing Operator Qualification (OQ) scope to cover new construction and certain other currently uncovered tasks, require operators use trained and qualified individuals when performing new construction work, and add program effectiveness requirements for operators to gauge the effectiveness of the OQ programs. PHMSA believes that requiring operators to use trained and qualified individuals would decrease human errors. PHMSA is also proposing to provide a renewal procedure for expiring special permits and proposing other minor and administrative changes. The proposed changes 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;
- Expanding the existing Operator Qualification (OQ) scope to cover new construction and previously excluded operation and maintenance tasks, addressing the National Transportation Safety Board's (NTSB) recommendation to clarify OQ requirements for control rooms, and extending the requirements to operators of Type A gathering lines in Class 2 locations and Type B onshore gas gathering lines;
- 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 permanent reversal of flow that lasts more than 30 days or a change in product (*e.g.,* from liquid to gas, from crude oil to highly volatile liquids (HVL));
- 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 three years a record of the reason why post-accident drug and alcohol test was not conducted;
- Adding a procedure to request PHMSA keep submitted information confidential;
- Adding reference to Appendix B of API 1104 related to in-service welding in parts 192 and 195; and
- Aaking minor editorial corrections.

B. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Several of the proposed changes would address sections 9 and 13 of the 2011 Act, which was signed into law on January 3, 2012. (Pub. L. 112–90). Section 9 of the 2011 Act requires PHMSA to specify a time limit for telephonic or electronic reporting of pipeline accidents and incidents. Section 13 of the 2011 Act (codified at 49 U.S.C. 60117) allows PHMSA to prescribe a fee structure and assessment methodology to recover costs associated with design reviews.

C. Costs and Benefits

PHMSA has estimated annual compliance costs at $3.1 million; less savings to be realized from the removal of farm taps from the DIMP requirements. Annual safety benefits cannot be quantified as readily due to data limitations, but are expected to be $1.6 million per year in avoided incident costs, plus numerous intangible benefits from the improved clarity and consistency of regulations and required post-incident drug and alcohol test decision justification. Although the quantified benefits do not exceed the estimated costs, PHMSA believes that these non-quantified benefits are significant enough to outweigh the costs of compliance. PHMSA believes that updating regulations, providing clarification, and providing methods for assessment tools by incorporating consensus standards all help to improve compliance with pipeline safety regulations and to reduce the likelihood of a serious pipeline incident. In particular, proposed operator qualification provisions ensure that pipeline construction personnel and operations and maintenance personnel have the appropriate skills for the functions they are performing. This would reduce the likelihood of human error-related incidents. At an annual compliance cost of $3.1 million, the proposed changes would be cost effective if they prevented a single fatal incident over a three-year period.

I. Accident and Incident Notification

Summary

This proposed rulemaking action would 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.

Background

PHMSA requires pipeline owners and operators to notify the National Response Center (NRC) by telephone or electronically at the earliest practicable moment following discovery of an incident or accident (§§ 191.5 and 195.52). In an advisory bulletin published on September 6, 2002; 67 FR 57060, PHMSA advised owners and operators of gas and hazardous liquids pipeline systems and liquefied natural gas (LNG) facilities that reporting at the earliest practicable opportunity usually means one to two hours after discovery of the incident.

Justification for the Recommended Change

On January 3, 2012, President Obama signed into law the 2011 Act. Section 9 of the 2011 Act directs PHMSA to require pipeline operators to make incident/accident telephonic notifications at the earliest practicable moment following confirmed discovery of an accident or incident and not later than 1 hour following the time of such confirmed discovery.

PHMSA proposes to revise the 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 the confirmed discovery of an accident or incident, but not later than one hour following the time of such confirmed discovery. Further, we are proposing to require operators to revise or confirm that initial notification within 48 hours of confirmed discovery of the accident or incident. Prompt reporting of a pipeline incident to the NRC is crucial to Federal investigators' ability to investigate and resolve pipeline safety concerns. Once a report is made, investigators must decide at the outset whether a full Federal investigation is necessary. Failure to report promptly hinders the decision making process and could jeopardize the outcome of any subsequent investigation and threaten public safety. Delays in reporting caused by an operator waiting until the operator definitely determines an event meets the reporting criteria would defeat a fundamental purpose of the 2011 Act, which is to give PHMSA and other agencies the earliest opportunity to assess whether an immediate response to a pipeline incident is needed.

As demonstrated by PHMSA's past enforcement actions, ''discovery'' has been evaluated on a case-by-case basis considering the totality of the circumstances. Because the statute requires reporting after ''confirmed discovery,'' PHMSA proposes to define the term in §§ 191.3 and 195.2 as ''when there is sufficient information to determine that a reportable event has occurred even if an evaluation has not been completed.'' After a more thorough investigation, the operator can submit more detailed information in the written incident report. This policy of erring on the side of caution ensures that delays in reporting incidents would be avoided. PHMSA seeks comment on the proposed definition of ''confirmed discovery'' and how it would affect operators in their evaluation of an incident or accident. In particular, PHMSA is interested in alternative definitions of ''confirmed discovery'' (*e.g.,* if an operator were to receive two different notifications that validate each other) and the advantages the alternative definitions have over the proposed definition.

II. Cost Recovery for Design Reviews

Summary

This proposed rulemaking action would 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 either overall design and construction costs totaling at least $2,500,000,000 or that contain new and novel technologies.

Background

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 issued guidance in January 2013, on its Web site to clarify the meaning of the term ''new or novel technologies or design'' as meaning, ''any products, designs, materials, testing, construction, inspection, or operational procedures that are not addressed in title 49 Code of Federal Regulations (CFR) parts 192, 193, or 195 due to technology or design advances and innovation.'' PHMSA developed this definition to include any technologies that are developed or have existed and are being adopted widely due to developments other than technology or innovation.

Justification for the Recommended Changes

PHMSA conducts facility design safety reviews in connection with proposals to construct, expand, or operate gas or hazardous liquid pipelines or liquefied natural gas pipeline facilities. Reviews include design, construction, and operational inspections and oversight. These reviews divert a significant amount of PHMSA's limited resources from the agency's pipeline safety enforcement responsibilities.

While PHMSA's pipeline account is funded entirely by user fees on the pipeline industry, PHMSA does not currently recover costs incurred specifically while conducting these reviews for pipeline operators. Section 13 of the 2011 Act permits PHMSA to require the entity or individual proposing the project to pay the costs incurred by PHMSA relating to such reviews.

Historically, PHMSA's pipeline safety costs associated with new pipeline design and construction reviews and inspections have been paid for through Pipeline User Fee collections. As major pipeline construction projects increase, PHMSA's inspection hours and costs have increased on major projects, diverting resources away from other Agency priorities. In this NPRM PHMSA is taking the first step in proposing to exercise the cost recovery authority described in Section 13(a) of the 2011 Act by prescribing a fee structure and assessment methodology that is based on the costs of providing these reviews that are initiated by the pipeline operator. However, in terms of budgetary scoring, Section 13 allows for the collection of the fee as a mandatory receipt. However, the Administration would like to use these fees as an offset for discretionary spending, and as such, PHMSA has proposed that appropriations language in the last several Budgets to make this a discretionary offsetting fee. Neither the Consolidated Appropriations Act of 2014 nor the Consolidated and Further Continuing Appropriations Act of 2015 enacted language that would make this a discretionary offsetting fee. Hence, PHMSA is proposing this portion of the ANPRM under the assumption that Congress will enact a revision to make this a discretionary offsetting fee before PHMSA would issue a final rule to implement the fee.

PHMSA believes that a review of a large project or new technology that has safety benefits in quality control would drain the agency's resources without any cost recovery mechanism. PHMSA has developed a sample master cost recovery agreement that would be used between PHMSA and the applicant for a project proposal meeting the criteria of proposed 49 CFR part 190, subpart D requirements. The sample master cost recovery agreement will be posted on PHMSA's Web site and in Docket No. PHMSA–2013–0163. A master cost recovery agreement would include at a minimum:

(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;

(7) Provisions for terminating the agreement; and

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

III. Operator Qualification Requirements

Summary

This proposed rulemaking action would amend the Federal pipeline safety regulations in 49 CFR parts 192 and 195 relative to operator qualification requirements. The amendments would include: Expanding the scope of OQ requirements to cover new construction and certain previously excluded operation and maintenance tasks, extending the OQ requirements to operators of Type A gas gathering lines in Class 2 locations, Type B onshore gas gathering lines, and regulated rural hazardous liquid gathering lines, requiring a program effectiveness review, and adding new recordkeeping requirements. The proposed changes would enhance the OQ requirements by clarifying existing requirements and addressing NTSB recommendation to extend operator qualification requirements to control center staff involved in pipeline operational decisions (Safety Recommendation P–12–8).

Background

Sections 101 and 201 of the Pipeline Safety Reauthorization Act of 1988 (Pub. L. 100–561; October 31, 1988) authorize PHMSA to require all individuals responsible for the operation and maintenance of pipeline facilities to be tested for qualifications and to be certified to perform such functions. PHMSA published a final rule on August 27, 1999; 64 FR 46853 for the qualification of pipeline personnel.

1. Public Meeting

Over 650 individuals from various stakeholder groups attended PHMSA's public meeting on OQ History and Milestones in January 2003 in San Antonio, Texas to discuss gaps between the OQ rule and actual operations in the field.

2. ASME Standard

ASME standard, ASME B31Q (''Pipeline Personnel Qualification'') was revised in October 2010, to address many OQ issues identified at the public meeting. An OQ team reviewed the standard in detail and determined that while the standard provided detailed guidance in most areas, PHMSA should instead amend the current regulation to address areas that had not been addressed in the revised ASME standard.[1]

3. NTSB Recommendation

The NTSB issued the following safety recommendation to PHMSA on July 25, 2012, (P–12–8):

> Extend operator qualification requirements in Title 49 Code of Federal Regulations Part 195 Subpart G to all hazardous liquid and gas transmission control center staff involved in pipeline operational decisions.

Although our existing Control Room Frequently Asked Questions (B.01, B.03 & B.05) (*http://primis.phmsa.dot.gov/crm/faqs.htm*) all touch on the topic of supervisors or others intervening in control room operations, there are no specific OQ program requirements. Therefore, PHMSA is proposing explicit control room team training requirement for all individuals who would be reasonably expected to interface with controllers during normal, abnormal or emergency situations in §§ 192.631(h) and 195.446(h).

4. Gathering Lines

PHMSA issued a final rule on March 15, 2006; 71 FR 13289 that revises the methodology used to identify regulated onshore gas gathering lines and implemented a tiered compliance approach to address potential risk. In a final rule issued on June 3, 2008; 73 FR 31634, PHMSA defined the criteria to identify a regulated onshore hazardous liquid gathering line. In both instances, PHMSA allowed a modified approach for recordkeeping, requiring only a description of the processes used to

[1] The OQ team consists of members from PHMSA and several State pipeline safety agencies.

qualify personnel instead of a description of qualification methods for each individual who is allowed to perform tasks on Type A gas gathering lines in Class 2 locations or regulated hazardous liquids gathering lines in rural locations. PHMSA has determined that this approach fails to ensure that individuals possess the requisite knowledge, skills, and abilities to perform the actual work. Additionally, in the March 2006 rulemaking, PHMSA subjected operators of Type B onshore gas gathering lines to a very limited set of required compliance activities, excluding and OQ requirements. Having a properly trained and qualified workforce is necessary and paramount to perform work on any category of pipeline and to solidify a consistent application of OQ across all sectors of pipeline transportation.

5. Control Room Team Training

NTSB issued the following safety recommendation to PHMSA on July 25, 2012, (P–12–7):

> Develop requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes.

Although not an explicit requirement, a number of the sections in the Control Room Management regulations, along with the inspection guidance and related Frequently Asked Questions, already touch on the concept of team training for control room personnel and others who would likely work together as a team during normal, abnormal, and emergency situations. PHMSA believes a requirement for control room team training would better prepare all individuals who would be reasonably expected to interface with controllers (control room personnel) during normal, abnormal or emergency situations. While the CRM regulations call out certain specific individuals such as controllers, supervisors, and field personnel, understanding of the requirements of CRM 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, as recommended by NTSB, PHMSA is proposing to require control room team training in §§ 192.631(h) and 195.446(h).

Justification for the Proposed Changes

The industry standard, ASME B31Q, Pipeline Personnel Qualification, defines covered task as ''those tasks that can affect the safety or integrity of the pipeline''.

The current rule is not prescriptive and the resulting flexibility built into the performance-based rule makes it difficult to measure operator's compliance with the rule. Under the current regulation, a covered task is an activity, defined by the operator that meets the 4-part test:

(1) Is performed on a pipeline facility;

(2) Is an operations or maintenance task;

(3) Is performed as a requirement of this part; and

(4) Affects the operation or integrity of the pipeline.

Many of the pipeline safety regulations are performance based, rather than prescriptive requirements. The OQ regulations require operators to identify covered tasks for all of their operations and maintenance activities that are required by parts 192 and 195, regardless of whether such activities arise from performance-based regulations or from more prescriptive requirements. It's the operator's responsibility to identify their unique and specific tasks and terminology in both their operations and maintenance documentation, as well as ensure these tasks are covered tasks in the Operator Qualification Program.

Many O&M tasks (part 2 of the 4-part test) that an operator performs are not specifically called out in the regulation (part 3 of the 4-part test).

Performance based tasks may include activities, such as those involved in making repairs (while repairs are called out as a requirement of the regulations, specific terminology such as mud plugging, pipefitting, installing Clockspring, etc. associated with making repairs is not). Making pipeline repairs in a safe manner involves myriad tasks that may vary from one job to another and from one operator to another. While the current performance based regulations provide flexibility for each operator to identify those particular repair tasks, the proposed rule to define covered tasks is clearer and helps to eliminate confusion over whether performance based tasks are ''performed as a requirement of this part.'' Most of the proposed OQ changes are not significant because the existing sections are renumbered or combined with other sections. However, this proposed rule includes two new requirements: (1) Includes OQ requirements for new constructions by changing the Scope; and (2) adds a new program effectiveness requirement to ensure that operators complete a review of the effectiveness of their OQ program. PHMSA's proposed changes to the OQ rule at parts 192 and 195 are as follows:

1. Change the scope of the OQ rule in §§ 192.801 and 195.501 to revise the method of determining a ''covered task.'' Instead of determining a covered task by the ''4-part test,'' PHMSA is proposing to define a covered task as any maintenance, construction or emergency response task the operator identifies as affecting the safety or integrity of the pipeline facility. The ''4-part test'' omitted important tasks, such as all construction tasks on new pipelines and certain operation and maintenance tasks.

2. Update the ''General'' sections of §§ 192.809 and 195.509 to remove the implementation dates that no longer affect the implementation requirements for operators. In addition, after they are updated §§ 192.809 and 195.509 are renumbered as §§ 192.805 and 195.505.

3. Change the requirements in §§ 192.805 and 195.505 by adding new definitions, deleting an obsolete date for training requirements and clarify the need for training individuals performing covered tasks. Additionally, we are adding a new requirement for evaluators of individuals performing covered tasks, including training requirements for new construction tasks as the current OQ requirements do not include new construction tasks.

4. Add a ''Program Effectiveness'' requirement at §§ 192.807 and 195.507 to ensure that operators complete a review of the effectiveness of their OQ program. The review would include ensuring that procedures that were amended have been captured in the necessary portions of the OQ program.

5. Add record requirements in §§ 192.809 and 195.509 that are normally reviewed during the inspection of OQ programs and are necessary to provide a thorough overview of an OQ program. The additional records would include records that document evaluators' performance and program effectiveness.

6. Add a new paragraph (b)(5) to §§ 192.631 and 195.446 to require each

operator to define the roles and responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers. PHMSA believes this change would reinforce that operators need to declare the roles, responsibilities, and qualifications of all others who, at times, could intervene in control room operations.

7. Add a new subparagraph in the ''Qualification Program'' sections as §§ 192.805(b)(7) and 195.505(b)(7) proposing requirements addressing management of change and the communication of those changes. This proposed section would ensure that weaknesses of a program are found and corrections are made with notification to those affected, and

8. Modify §§ 192.9 and 195.11 to require operators to establish and administer an OQ program covering personnel who perform work on Type A gas gathering lines in Class 2 locations, regulated Type B onshore gas gathering lines and regulated hazardous liquids gathering lines in rural locations.

IV. Special Permit Renewal

Summary

This proposed rulemaking action would amend § 190.341 of the Federal pipeline safety regulations to add procedures for renewing a special permit.

Background and Justification

As defined in § 190.341(a), a special permit is an order by which PHMSA waives compliance with one or more of the pipeline safety regulations if it determines that granting the permit would ''not be inconsistent with pipeline safety.'' Special permits are authorized by statute in 49 U.S.C. 60118(c), and the application process is set forth in § 190.341. 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 is committed to public involvement and transparency in special permit proceedings and publishes notice of every special permit application received in the **Federal Register** for comment.

In the past, PHMSA has included an expiration date for certain special permits depending on the nature of the permit. By doing so, PHMSA is able to ensure that these special permits will be reviewed again no later than the expiration date. This process ensures that a special permit will not continue to be used if it is no longer in the best interest of public safety.

PHMSA is proposing to add a renewal procedure to the pipeline safety regulations for those Special Permits that have expiration dates. This special permit renewal procedure will ensure the permit conditions are still valid for the pipeline and if changes and updates are required to maintain safety and the environment.

V. Farm Taps

Summary

This proposed rulemaking action would amend 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).

Background

On October 29, 2012, PHMSA received a request from the Interstate Natural Gas Association of America (INGAA), asking if PHMSA covers the farm tap issue on the upcoming miscellaneous issue rulemaking. In addition, PHMSA received a February 15, 2013, written letter from the National Association of Pipeline Safety Representatives (NAPSR) requesting an exemption of farm taps from the DIMP requirements as follows:

The letter requested PHMSA to take the following actions relative to the applicability of DIMP to ''Farm Taps'':

1. Amend the applicable part 192 sections to exempt those pipelines commonly referred to as ''farm taps'' (a term originating from industry jargon) from the requirements of Subpart P, Gas Distribution Pipeline Integrity Management; and

2. Amend part 192 to include periodic inspection requirements in a new section covering ''pressure regulating and over-pressure-relief equipment'' on a pipeline that originates from a transmission, gathering, or production pipeline that serves a service line.

In support of the above, NAPSR offered the following:

- Farm taps are distribution service lines per § 192.3 ;
- During the DIMP rulemaking, little consideration was given to the potential impact or appropriateness of subjecting farm taps to DIMP;
- The risk to the public from a failure on a farm tap is generally lower in Class 1 and Class 2 locations in which farm taps are typically located and operated;
- Currently the regulator and relief equipment with farm taps are not subject to over pressurization protection requirements associated with pressure limiting stations.

This proposal originated with the NAPSR DIMP Implementation Task Force and was subsequently approved by the NAPSR Board in January 2013.

As NAPSR described it, ''farm tap'' is industry jargon for a pipeline that branches from a transmission, gathering, or production pipeline to deliver gas to a farmer or other landowner. Historically, PHMSA and its predecessor agencies have held that farm taps are service lines—a subset of distribution pipelines. Rulemaking proceedings and responses to requests for interpretation have recognized this dating as far back as 1971.

On December 4, 2009, PHMSA published the DIMP final rule (74 FR 63906) for gas distribution pipelines. That rule applies IM requirements to all distribution pipelines. Unlike the IM requirements for hazardous liquid or gas transmission pipelines, the DIMP requirements do not focus on a subset of pipelines in ''high consequence areas,'' but instead apply to all distribution pipelines, including farm taps.

Justification for the Recommended Changes

Farm taps are mostly located in less-populated areas (Class 1 and 2 locations). The risk to the public from farm taps is generally low, but the risk is dependent upon the service line in which the farm tap is employed, the environment in which it operates, and the consequence of an overpressurization event. DIMP is written to identify needed risk control practices for threats associated with distribution systems, whereas threats to typical farm taps are limited, and most are already addressed within part 192. Therefore, in response to the INGAA and NAPSR requests, PHMSA is proposing to amend part 192 to exempt farm taps from the requirements of part 192, subpart P—Gas Distribution Pipeline Integrity Management. However, to better protect customers served by these lines, PHMSA is proposing to amend part 192, subpart M—Maintenance by adding a new section that prescribes inspection activities under the existing States and Federal pipeline safety inspection programs for pressure regulators and overpressurization protection equipment on service lines that originate from transmission, gathering, or production pipelines. Currently, Federal pipeline safety requirements do not include overpressurization protection for farm taps. Therefore, this requirement would include inspection of farm-tap pressure regulating/limiting device, relief device, and automatic shutoff device every 3-years to make sure these safety equipment are in good working conditions.

VI. Reversal of Flow or Change in Product

Summary

PHMSA published a final rule on November 26, 2010 (75 FR 72878) that established and required participation in the National Registry of Pipeline and LNG Operators. The final rule amended the Federal pipeline safety regulations to require operators to notify PHMSA electronically of the occurrence of certain events no later than 60 days before the event occurs.

In this notice of proposed rulemaking (NPRM), PHMSA proposes 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 proposed rule 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 proposed 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.

VII. Pipeline Assessment Tools

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 notice 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.

Section 195.452 specifies the techniques that must be used to perform the required periodic IM assessments.[2] ILI is among the allowed techniques. Supervisory Control and Data Acquisition (SCADA) system 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.

When the IM regulations were established, consensus standards did not exist in addressing how these techniques should be applied. Since then, the American Petroleum Institute (API), National Association of Corrosion Engineers (NACE), and the American Society for Non-Destructive Testing (ASNT) published standards for using ILI and SCCDA as assessment techniques. Also, PHMSA received a petition from NACE requesting that PHMSA incorporate ANSI/NACE Standard RP0204, NACE Standard RP0102–2002, and seven other NACE standards into 49 CFR parts 192 and 195. These referenced consensus standards address the selection of in-line inspection tools for assessing the physical condition of in-service hazardous liquids pipelines. Since the NACE petition, two of these standards have been developed from recommended practices into NACE Standard Practice (SP0102–2010 and NACE SP0204–2008.)

In addition, NTSB issued the following safety recommendation to PHMSA on July 10, 2012, (P–12–3):

> Revise Title 49 Code of Federal Regulations 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable.

This proposed rule would incorporate by reference consensus standards for assessing the physical condition of in-service hazardous liquids pipelines using ILI and SCCDA. Incorporation of the consensus standards would assure better consistency, accuracy and quality in pipeline assessments conducted using these techniques. This proposal addresses those parts of NTSB Recommendation P–12–3—identifying crack defects and seam corrosion by using crack tools and circumferential tools—by incorporating the above cited industry standards. The remainder of NTSB Recommendation P–12–3 will be addressed in PHMSA's rulemaking titled ‘‘Pipeline Safety—Safety of On-Shore Hazardous Liquid Pipelines.’’ Therefore, PHMSA proposes to incorporate by reference the following consensus standards 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). Also, PHMSA proposes to allow 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.

Note that this proposed rulemaking action addresses only part 195, but PHMSA is considering a similar proposed requirement in 49 CFR part 192.

Justification for the Recommended Incorporation

Incorporation of the consensus standards would 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 considers that the consistency, accuracy, and quality of pipeline ILI would be improved by

[2] Operators are allowed to use techniques not specifically identified in these sections provided that the techniques provide an equivalent understanding of pipe condition and that operators notify PHMSA in advance of their use of such other techniques.

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 proposing to adopt 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, is proposing that use of these tools continue to be allowed 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 would provide further instructions when 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 would 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 would ensure that all operators use these standards. Overall cost would not change, because these consensus standards would 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 would 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.''

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 would 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 would 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 (*https://*

primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=199). 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 this proposed rule (proposed § 195.588) that an operator must consider if the operator uses direct assessment to assess SCC.

SCC was also a topic in an advance notice of proposed rulemaking (ANPRM) published by PHMSA on October 18, 2010 (75 FR 63774). The ANPRM addressed several potential changes to the regulations governing the safety of hazardous liquids pipelines. Among other topics, it posed a number of questions concerning SCC, including whether the NACE standard addresses the full life cycle concerns associated with SCC, NACE's efficacy, and whether the NACE standard or any other standards should be adopted to govern the conduct of SCC assessments. PHMSA received a limited number of comments to the ANPRM that addressed the SCC questions. Joint comments from the American Petroleum Institute and the Association of Oil Pipelines (API–AOPL) noted that NACE SP0204–2008 is a reasonable standard but does not address all aspects of SCC control. API–AOPL noted that forthcoming updates of API Standard 1160, ''Managing System Integrity for Hazardous Liquid Pipelines,'' and API Standard 1163, ''In-Line Inspection Systems Qualification Standard,'' would be better references to address SCC management. The Texas Pipeline Association recommended against adopting the NACE standard, contending that it is too new for operators to have significant experience with it. The National Association of Pipeline Safety Representatives suggested that PHMSA should require an assessment for SCC any time there is a credible threat of its occurrence; however, API–AOPL suggested that requiring assessment for ''any credible threat'' was too extreme and that some significance threshold should be used. The National Resources Defense Council suggested the need for special attention to sulfide-assisted SCC in pipelines carrying diluted bitumen (*i.e.,* tar sands oil). No commenters indicated knowledge of statistics supporting the efficacy of any current SCC standard or guideline.

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 would adopt them.

As for NAPSR's comment on assessing any credible SCC threat, PHMSA believes that any proposed requirements for SCC would need to be considered in a separate rulemaking effort. States always have option to make requirements more stringent. PHMSA will consider incorporating updates to API 1160 once that standard is published. PHMSA will also continue to consider the comments received in response to its ANPRM.

PHMSA is proposing to revise § 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 proposal would not require that SCCDA assessments be conducted, but it would 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.

VIII. Electronic Reporting of Drug and Alcohol Testing Results

PHMSA's pipeline safety regulations at §§ 191.7 and 195.58 require electronic reporting of most pipeline safety reports through the PHMSA Portal. PHMSA proposes to also require electronic reporting for anti-drug testing results required at § 199.119 and alcohol testing results required at § 199.229. Pipeline operators with fewer than 50 covered employees are required to submit these reports only when PHMSA provides written notice. PHMSA proposes to modify these regulations to specify that PHMSA will provide notice to operators in the PHMSA Portal.

IX. Post-Accident Drug and Alcohol Testing

The NTSB issued the following safety recommendation to PHMSA (September 26, 2011, NTSB Recommendation P–11–12):

> Amend §§ 199.105 and 199.225 to eliminate operator discretion with regard to testing of covered employees. The revised language should require drug and alcohol testing of each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident.

PHMSA proposes to 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.

PHMSA's regulations require 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 is only implied in the regulation, and the implied requirement is generally followed. PHMSA proposes to add a section to the post-accident drug testing regulation to require documentation of the decision and to keep the documentation for at least three years.

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

When any 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 have a procedure in the pipeline safety regulations by which a request can be made for confidential treatment of information. PHMSA has such a procedure in its hazardous materials safety regulations. Therefore, for consistency in the way we treat submitted information, PHMSA proposes a procedure where anyone who submits information may request for confidential treatment of that information. As part of the procedure, if PHMSA receives a request for the record(s), PHMSA would conduct a review of the records under the Freedom of Information Act.

In accordance with Departmental FOIA regulations, if a request is received for information that has been designated by the submitter as confidential, we would notify the submitter and provide an opportunity to the submitter to submit any written objections. Whenever a decision is made to disclose such information over the objections of a submitter, we would notify the submitter in writing at least five days before the date the information is publicly disclosed.[3]

XI. In Service Welding

In 1987, the U.S. Department of Transportation, Office of Pipeline Safety issued Alert Notice ALN–87–01 which advised pipeline owners and operators of a pipeline incident involving the welding of a full encirclement repair sleeve on a 14'' API 5L X52 pipeline near King of Prussia, PA. The pipeline failure released thousands of barrels of gasoline and was directly related to cracks developed in a fillet weld of a Type B full encirclement repair sleeve. The metallurgical analysis conducted by Battelle Laboratories concluded hydrogen and stress caused cracking of the excessively hard heat affected material in the carrier pipe. Contributing factors included poor weldability of the carrier pipe due to its high carbon equivalent, a very high cooling rate of the weld due to liquid product being present inside the pipeline during welding, the presence of hydrogen in the welding environment due to the use of cellulosic coated electrodes, residual stresses, and high restraint inherent in the geometry of the sleeve weldment. The alert notice strongly recommended that the use of welding procedures similar to the one that failed (use of cellulosic electrodes) be discontinued and that magnetic particle inspection has been proven to be an accurate method for detecting cracked in-service fillet welds.

In response to this failure and advancements in pipeline and welding engineering, the American Petroleum Institute (API) developed, improved, and now includes Appendix B *In-service Welding* to the API Standard 1104 *Welding of Pipelines and Related Facilities.* API 1104 Appendix B contains provisions for the development of welding procedures and welder qualifications that address the safety concerns of welding to an in-service pipeline. 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. At the present time, typical industry developed in-service welding procedures utilize all or some combinations of low hydrogen electrodes, preheat, temper bead deposition sequence, heat input control, cooling rate analysis, analysis based on pipe/sleeve/fitting material carbon equivalence, and address wall thickness/burn-through concerns. The Office of Pipeline Safety alert notice encouraged the development and use of welding procedures that address improvements in pipeline safety and many operators have developed in-service welding procedures.

Unfortunately, parts 192 and 195 were not modified to include the addition of API 1104 Appendix B as an acceptable section for the development of welding procedures and welder qualification. At the present time, parts 192 and 195 only adopt into Federal Regulation Sections 5, 6, 9 and Appendix A. This proposed rule seeks to rectify this oversight and state the acceptability of developing procedures and qualifying welders to Appendix B of API 1104. Currently, PHMSA does not allow in service welding, but this proposal would allow the operators to follow Appendix B of API 1104 for in service welding. Therefore, PHMSA proposes to revise 49 CFR 192.225, 192.227, 195.214, and 195.222 to add reference to API 1104, Appendix B.

XII. Editorial Amendments

In this NPRM, PHMSA is also proposing to make the following editorial amendments to the pipeline safety regulations:

Summary of Correction to § 192.175(b)

PHMSA's predecessor agency, the Research and Special Programs Administration, issued a final rule on July 13, 1998; 63 FR 37500 to provide metric equivalents to the English units for informational purposes only. Operators were required to continue using the English units for purposes of compliance and enforcement. The metric equivalent provided in § 192.175(b) ''C=(DxPxF/48.33) (C=(3DxPxF/1,000)''—is incorrect. The correct formula is: ''C = (3D*P*F)/1000) (C = (3D*P*F*)/6,895)'', where, ''C = (3D*P*F)/1000)'' is in inches (English unit), and ''(C = (3D*P*F*)/6,895)'' is in millimeters (metric conversion).

Summary of Correction to § 195.64(a) and § 195.64(c)(1)(ii)

PHMSA published a final rule on November 26, 2010; 75 FR 72878, which established the National Registry of Pipeline and LNG Operators. In the rule, PHMSA inadvertently omitted the inclusion of carbon dioxide in the operating commodity types. To maintain consistency with the rest of part 195, this proposed rule would amend the language in §§ 195.64(a) and 195.64(c)(1)(ii) to correct the term ''hazardous liquid'' to read ''hazardous liquid or carbon dioxide.''

In § 195.248, the conversion to 100 feet is mistakenly stated as 30 millimeters. Therefore, PHMSA proposes to replace the phrase ''100 feet (30 millimeters)'' to correctly read ''100 feet (30.5 meters).''

In addition, low stress pipelines are not specified in § 195.452. Section 195.452 applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. Therefore, PHMSA proposes to add a new paragraph (a)(4) to clarify the applicability of § 195.452 to low stress pipelines as described in § 195.12.

XIII. 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 (Pub. L. 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

[3] Note—the Departmental FOIA regulations say that a written notice of intent to disclose will be forwarded a reasonable number of days prior to the specified date upon which disclosure is intended. See 49 CFR 7.17. See also the Hazmat regulations in 49 CFR 105.30.

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 requires the Secretary not to issue guidance or a regulation to incorporate 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.''

Further, the Office of the Federal Register issued a November 7, 2014, rulemaking (79 FR 66278) that revised 1 CFR 51.5 to require that agencies detail in the preamble of a proposed rulemaking the ways the materials it proposes to incorporate by reference are reasonably available to interested parties, or how the agency worked to make those materials reasonably available to interested parties. In relation to this proposed rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been proposed for incorporation by reference. Access to these standards will be granted until the end of the comment period for this proposed rulemaking. Access to these documents can be found on the PHMSA Web site at the following URL: *http://www.phmsa.dot.gov/pipeline/regs* under ''Standards Incorporated by Reference.''

XIV. Regulatory Analyses and Notices

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

This proposed rule is a non-significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735), and therefore is reviewed by the Office of Management and Budget. This proposed rule is non-significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034) because of substantial congressional, State, industry, and public interest in pipeline safety.

Executive Orders 12866 and 13563 require 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 notice, PHMSA is proposing 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;
- Modify operator qualification requirements including addressing a NTSB recommendation to clarify OQ requirements for control rooms;
- Add provisions for the renewal of expiring special permits;
- Exclude farm taps from the requirements of the DIMP requirements while proposing safety requirements for the farm taps
- To address NTSB recommendations for control room team training and other recommendations;
- Require pipeline operators to report to PHMSA 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;
- 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;
- Add a procedure to ensure PHMSA keeps submitted information confidential.
- Adding reference to Appendix B of API 1104 related to in-service welding in parts 192 and 195; and
- Making minor editorial corrections.

As a summary of the costs/benefits the annual compliance costs were estimated at approximately $3.1 million, less savings to be realized from the removal of farm taps from the DIMP requirements. Annual safety benefits could not be quantified as readily due to data limitations but were estimated in the range of $1.6 million per year in avoided incident costs, plus numerous intangible benefits from the improved clarity and consistency of regulations and improved abilities to conduct post-incident investigations. Although the quantified benefits do not exceed the quantified costs, PHMSA believes that these non-quantified benefits are significant enough to outweigh the costs of compliance. In particular, improvements to Operator Qualification and post-incident investigation may prevent a future high-consequence event. At an annual compliance cost of $3.1 million, the proposed new Operator Qualification and post-accident testing requirements would be cost-effective if they prevented a single fatal incident over a 3-year period.

COSTS VS BENEFITS TABLE

Annual Costs	$3.1 million.
Annual Benefits	$1.6 million plus unquantified safety benefits and farm tap savings.

A regulatory evaluation containing a statement of the purpose and need for this rulemaking and an analysis of the costs and benefits is available in Docket No. PHMSA–2013–0163.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities. PHMSA is proposing to add new requirements and make changes to the existing pipeline safety regulations.

Description of the reasons why action by PHMSA is being considered.

PHMSA is proposing to amend 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 proposed rule. A special permit renewal procedure is proposed so that pipeline operators would have a renewal procedure to follow to renew their expiring special permits. The OQ requirements scope is expanded for new constructions and a program effectiveness review is required so that Operators can review their OQ programs for effectiveness. In addition, other non-substantive changes are proposed 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; process to request submitted information be kept confidential similar to the current Hazmat process in 49 CFR 105.30; and, editorial amendments to correct some errors or outdated deadlines.

Succinct statement of the objectives of, and legal basis for, the proposed 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)). The proposed rule would create changes in the regulations consistent with the protection of persons and property.

Description of small entities to which the proposed rule will apply.

The Initial Regulatory Flexibility Analysis finds that the proposed 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 OQ provision would entail new costs for small entities in the range of $160.00 per employee per year, or about 0.3% of salary for a typical pipeline employee. The provision to document the reason for not drug testing post-accident would add $74.00 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 not expected to be significant.

Description of any significant alternatives to the proposed rule that accomplish the stated objectives of applicable statutes and that minimize any significant economic impact of the proposed 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.

Questions for Comment on Regulatory Flexibility Analysis

PHMSA is requesting public comments for the Regulatory Flexibility Analysis as follows:

1. Provide any data concerning the number of small entities that may be affected.

2. Provide comments on any or all of the provisions in the proposed rule with regard to (a) the impact of the provisions, if any, and (b) any alternatives PHMSA should consider, paying specific attention to the effect of the rule on small entities.

3. Describe ways in which the rule could be modified to reduce any costs or burdens for small entities.

4. Identify all relevant Federal, state, local, or industry rules or policies that may duplicate, overlap, or conflict with the proposed rule and have not already been incorporated by reference.

Executive Order 13175

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

Paperwork Reduction Act

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 the proposals in this rulemaking 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 also proposes to create 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: July 31, 2015.

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 proposing to revise the form PHMSA F7000–1 instructions for editorial and clarification purposes. This proposal would result in a modification to the Hazardous Liquid Accident Report form (Form PHMSA F 7000–1) to include the concept of ''confirmed discovery'' as proposed in this rule.

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 proposal would result in a modification to the Gas Distribution Incident Report form (Form PHMSA F 7100.1) to include the concept of ''confirmed discovery'' as proposed in this rule.

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:* Qualification of Pipeline Safety Training''

OMB Control Number: 2137–0600.

Current Expiration Date: July 31, 2018.

Abstract: All individuals responsible for the operation and maintenance of pipeline facilities are required to be properly qualified to safely perform their tasks and keep proper documentation as required by PHMSA regulations. As a result of the changes proposed in this NPRM, PHMSA estimates a total of 16,008 new employees will be subject to participate in an OQ plan either as a result of new gathering line requirements or because of newly covered tasks. Participation in an OQ plan necessitates the retention of records associated with those plans. This proposal will impose a recordkeeping requirement for Operator Qualifications on the estimated 16,008 newly covered employees that will be affected by this rule. As a result, 16,008 responses and 42,668 annual burden hours will be added to the existing information collection burden.

Affected Public: Operators of PHMSA-Regulated Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 31,835

Total Annual Burden Hours: 509,360.

Frequency of Collection: On occasion.

4. *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 proposed rule would amend § 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 proposed 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.

5. *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 NPRM proposes to amend 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 609 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.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW., Washington, DC 20503. Comments should be submitted on or prior to September 8, 2015.

Unfunded Mandates Reform Act of 1995

PHMSA has determined that the proposed rule would not impose annual expenditures on State, local, or tribal governments of the private sector in excess of $153 million, and thus, does not require an Unfunded Mandates Act analysis.[4]

National Environmental Policy Act

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

1. Purpose and Need

PHMSA's mission is to protect people and the environment from the risks of hazardous materials transportation. The purpose of this proposed rule 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.

[4] The Unfunded Mandates Act threshold was $100 million in 1995. Using the non-seasonally adjusted CPI–U (Index series CUUR000SA0), that number is $153 million in 2013 dollars.

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 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 the proposed rule, PHMSA considered two alternatives:

(1) No action, or

(2) Propose revisions to the pipeline safety regulations to incorporate the proposed 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 proposed in this proposed rule 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 proposing to make 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. We are also proposing changes to the OQ requirements and drug and alcohol testing requirements and proposing methods for assessment tools by incorporating consensus standards by reference for in-line inspection and stress corrosion cracking direct assessment.

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 the proposed 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 the proposed 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 proposed 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 preliminarily determined that the selected alternative would have a positive, non-significant, impact on the human environment and welcomes comments on PHMSA's conclusion. The preliminary environmental assessment is available in Docket No. PHMSA–2013–0163.

Executive Order 13132

PHMSA has analyzed this proposed rule according to Executive Order 13132 (''Federalism''). The proposed 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 proposed rule does not impose substantial direct compliance costs on State and local governments. This proposed 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 proposed rule is not a ''significant energy action'' under Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use''). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this proposed rule as a significant energy action.

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 Part192

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, Safety devices.

49 CFR Part 199

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

In consideration of the foregoing, PHMSA is proposing to amend 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 is revised to read as follows:

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

■ 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.

* * * * *

■ 3. Amend § 190.341 by:

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

■ 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) * * *

(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) To continue using a special permit after the expiration date, the grantee of the special permit must apply for a renewal of the permit.

(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., East Building, 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:

(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:

(A) Pipe attributes: Pipe diameter, wall thickness, grade, and seam type; 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;

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

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

§ 190.343. Information made available to the public and request for confidential treatment.

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 confidential treatment. 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 information deleted.

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

(b) PHMSA Decision. PHMSA will decide whether to treat your information as confidential. We will notify you, in writing, of a decision to grant or deny confidentiality at least five days before the information is publicly disclosed, and give you an opportunity to respond

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

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: Construction route surveys, permitting activities, material purchasing and manufacturing, right of way acquisition, 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, as revised in 80 FR12762 (March 11, 2015), effective October 1, 2015, continues to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, and 60124, 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 there is sufficient information to determine that a reportable event may have occurred even if an evaluation has not been completed.

* * * * *

■ 8. In § 191.5, paragraph (a) is revised, paragraph (b)(5) is re-designated as paragraph (b)(6) and new paragraph (b)(5) and paragraph (c) are 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.

(b) * * *

(5) The amount of product loss.

* * * * *

(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 a revised 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)(iv) and (c)(1)(v) 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;

* * * * *

(iv) 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

(v) 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, as revised in 80 FR 12762 (March 11, 2015), effective October 1, 2015, continues to read as follows:

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

■ 11. In § 192.9, paragraph (c) is revised, paragraph (d)(8) is added, and the table in paragraph (e)(2) is revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) Type A lines. An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part. An operator must establish and implement an operator qualification program in accordance with Subpart N of this part.

(d) * * *

(8) Establish and implement an operator qualification program in accordance with Subpart N of this part.

* * * * *

(e) * * *

(2) If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission lines.	April 15, 2009.
Carry out a damage prevention program under § 192.614.	October 15, 2007.
Establish MAOP under § 192.619.	October 15, 2007.
Install and maintain line markers under § 192.707.	April 15, 2008.
Establish a public education program under § 192.616.	April 15, 2008.
Establish an operator qualification program according to Subpart N requirements if an operator of a Type A or Type B regulated onshore gathering line.	[date one year after publication of a final rule].
Other provisions of this part as required by paragraph (c) of this section for Type A lines.	April 15, 2009.

* * * * *

■ 12. 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.

■ 13. 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.

■ 14. 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).

* * * * *

■ 15. 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.

* * * * *

■ 16. In § 192.631, paragraphs (b)(3), (b)(4), (h)(4) and (h)(5) are revised and paragraphs (b)(5) and (h)(6) are 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 who would reasonably be expected to interact with controllers (control room personnel) during normal, abnormal or emergency situations.

* * * * *

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

§ 192.740 Pressure regulating, limiting, and overpressure protection—Individual service lines originating on production, gathering, or transmission pipelines.

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

(b) Each pressure regulating/limiting device, relief device, 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) gage 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.

■ 18. Section 192.801 is revised to read as follows:

§ 192.801 Scope.

This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks as defined in § 192.803 on a pipeline facility.

■ 19. Section 192.803 is revised to read as follows:

§ 192.803 Definitions.

For purposes of the subpart the following definitions apply:

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(1) Indicate a condition exceeding design limits; or

(2) Result in a hazard(s) to persons, property, or the environment.

Adversely affects means a negative impact on the safety or integrity of the pipeline facilities.

Covered task means an activity identified by the operator that affects the safety or integrity of the pipeline facility. A covered task includes, but is not limited to, the performance of any operations, maintenance, construction or emergency response task.

Direct and observe means the process where a qualified individual personally observes the work activities of an individual not qualified to perform a single covered task, and is able to take immediate corrective action when necessary.

*Emergency response task*s are those identified operations and maintenance covered tasks that could reasonably be expected to be performed during an emergency to return the pipeline facilities to a safe operating condition.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(1) Written examination;

(2) Oral examination;

(3) Work performance history review;

(4) Observation during;

(i) Performance on the job;

(ii) On the job training; or

(iii) Simulations; and

(5) Other forms of assessment

Knowledge, skills and abilities, as it applies to individuals performing a covered task, means that an individual can apply information to the performance of a covered task, has the ability to perform mental and physical activities developed or acquired through training, and has the mental and physical capacity to perform the covered task.

Qualified as it applies to an individual performing a covered task, means that an individual has been evaluated and can:

(1) Perform assigned covered tasks;

(2) Recognize and react to abnormal operating conditions that may be encountered while performing a particular covered task;

(3) Demonstrate technical knowledge required to perform the covered task, such as: equipment selection, maintenance of equipment, calibration and proper operation of equipment, including variations that may be encountered in the covered task performance due to equipment and environmental differences;

(4) Demonstrate the technical skills required to perform the covered task, for example:

(i) Variations required in the covered task performance due to equipment and/or new operations differences or changes;

(ii) Variations required in covered task performance due to conditions or context differences (*e.g.,* hot work versus work on evacuated pipeline); and

(5) Meet the physical abilities required to perform the specific covered task (*e.g.,* color vision or hearing).

Safety or integrity means the reliable condition of a pipeline facility (operationally sound or having the ability to withstand stresses imposed) affected by any operation, maintenance or construction task, and/or an emergency response.

Significant changes means the following as it relates to operator qualification:

(1) Wholesale changes to the program;

(2) Change in evaluation methods (*i.e.* performance and written to written only);

(3) Increases in evaluation intervals (*i.e.* from 1 to 5 years); or

(4) Removal of covered tasks (not including combining covered tasks).

Span of control means the ratio of nonqualified to qualified individuals where the nonqualified individual may be directed and observed by a qualified individual when performing a covered task, with consideration to complexity of the covered task and the operational conditions when performing the covered task.

■ 20. Section 192.805 is revised to read as follows:

§ 192.805 Qualification program.

(a) *General.* An operator must have and follow a written operator qualification program that meets the requirements of paragraph (b) of this section for all pipelines regulated under part 192. The written program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. chapter 601 if the program is under the authority of that state agency.

(b) *Program Requirements.* The operator qualification program must, at a minimum, include provisions to:

(1) Identify covered tasks;

(2) Complete the qualification of each individual performing a covered task prior to the individual performing the covered task;

(3) Ensure through evaluation that each individual performing a covered task is qualified to perform the covered task provided that:

(i) Review of work performance history is not used as a sole evaluation method.

(ii) Observation of on-the-job performance is not used as a sole method of evaluation. However, when on-the-job performance is used to complete an individual's competency for a covered task, the operator qualification procedure must define the measures used to determine successful completion of the on-the-job performance evaluation.

(4) Allow any individual who is not qualified to perform a covered task to perform the covered task if directed and observed by a qualified individual within the limitations of the established span of control for the particular covered task.

(5) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in part 191 of this chapter;

(6) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(7) Establish and maintain a Management of Change program that will communicate changes that affect covered tasks to individuals performing those covered tasks;

(8) Identify all covered tasks and the intervals at which evaluation of an individual's qualifications is needed;

(9) Provide training to ensure that any individual performing a covered task has the necessary knowledge, skills, and abilities to perform the task in a manner that ensures the safety and integrity of the operator's pipeline facilities;

(10) Provide supplemental training for the individual when procedures and specifications are changed for the covered task;

(11) Establish the requirements to be an Evaluator, including the necessary training; and

(12) Develop and implement a process to measure the program's effectiveness in accordance with § 192.805

(c) *Changes.* An operator must notify the Administrator or a State agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to *InformationResourcesManager@dot.gov,* or by mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, New Jersey Avenue SE., Washington, DC 20590.

■ 21. Section 192.807 is revised to read as follows:

§ 192.807 Program effectiveness.

(a) *General.* The qualification program must include a written process to measure the program's effectiveness. An effective program minimizes human error caused by an individual's lack of knowledge, skills and abilities (KSAs) to perform covered tasks. An operator must conduct the program effectiveness review once each calendar year not to exceed 15 months.

(b) *Process.* The process to measure program effectiveness must:

(1) Evaluate if the qualification program is being implemented and executed as written; and

(2) Establish provisions to amend the program to include any changes necessary to address the findings of the program effectiveness review.

(c) *Measures.* The operator must develop program measures to determine the effectiveness of the qualification program. The operator must, at a minimum, include and use the following measures to evaluate the effectiveness of the program.

(1) Number of occurrences caused by any individual whose performance of a covered task(s) adversely affected the safety or integrity of the pipeline due to any of the following deficiencies:

(i) Evaluation was not conducted properly;

(ii) KSAs for the specific covered task(s) were not adequately determined;

(iii) Training was not adequate for the specific covered task(s);

(iv) Change made to a covered task or the KSAs was not adequately evaluated for necessary changes to training or evaluation;

(v) Change to a covered task(s) or the KSAs was not adequately communicated;

(vi) Individual failed to recognize an abnormal operating condition, whether it is task specific or non-task specific, which occurs anywhere on the system;

(vii) Individual failed to take the appropriate action following the recognition of an abnormal operating condition (task specific or non-task specific) that occurs anywhere on the system;

(viii) Individual was not qualified;

(ix) Nonqualified individual was not being directed and observed by a qualified individual;

(x) Individual did not follow approved procedures and/or use approved equipment;

(xi) Span of control was not followed;

(xii) Evaluator or training did not follow program or meet requirements; or

(xiii) The qualified individual supervised more than one covered task at the time.

(2) [Reserved]

■ 22. Section 192.809 is revised to read as follows:

§ 192.809 Recordkeeping.

Each operator must maintain records that demonstrate compliance with this subpart.

(a) *Individual qualification records.* Individual qualification records must include:

(1) Identification of qualified individual(s),

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification;

(4) Qualification method(s);

(5) Evaluation to recognize and react to an abnormal operating condition, whether it is task-specific non-task specific, which occurs anywhere on the system;

(6) Name of evaluator and date of evaluation; and

(7) Training required to support an individual's qualification or requalification.

(b) *Program records.* Program records must include, at a minimum, the following:

(1) Program effectiveness reviews;

(2) Program changes;

(3) List of program abnormal operating conditions;

(4) Program management of change notifications;

(5) Covered task list to include all task specific and non-task specific covered tasks;

(6) Span of control ratios for each covered task:

(7) Reevaluation intervals for each covered task;

(8) Evaluations method(s) for each covered task; and

(9) Criteria and training for evaluators.

(c) *Retention period*—(1) *Individual qualification records.* An operator must maintain records of qualified individuals who performed covered tasks. Records supporting an individual's current qualification must be retained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks must be retained for a period of five years.

(2) *Program records.* An operator must maintain records required by paragraph (b) of this section for a period of five years.

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

§ 192.1003 What do the regulations in this subpart cover?

(a) *General.* Unless excepted 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 a service line that originates directly from a transmission, gathering, or production pipeline.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 24. The authority citation for part 195, as revised in 80 FR12762 (March 11, 2015), effective October 1, 2015, continues to read as follows:

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

■ 25. 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 there is sufficient information to determine that a reportable event may have occurred even if an evaluation has not been completed.

* * * * *

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.

* * * * *

■ 26. In § 195.3:

■ a. Add paragraph (b)(23);

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

■ c. Add paragraphs (g)(3) and (4) to the newly redesignated paragraph (g).

The additions read as follows:

§ 195.3 Incorporation by reference.

* * * * *

(b) * * *

(23) API Standard 1163, ''In-Line Inspection Systems Qualification Standard'' 1st edition, August 2005, (API Std 1163), IBR approved for § 195.591.

* * * * *

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

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

(2) [Reserved]

* * * * *

(g) * * *

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

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

■ 27. 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

■ 28. In § 195.11 paragraph (b)(11) is revised to read as follows:

§ 195.11 What is a regulated rural gathering line and what requirements apply?

* * * * *

(b) * * *

(11) Establish and implement an operator qualification program in accordance with Subpart G of this part before [DATE ONE YEAR AFTER DATE OF PUBLICATION OF A FINAL RULE IN THE **FEDERAL REGISTER**].

* * * * *

■ 29. 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]

■ 30. 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.

■ 31. In § 195.64, as amended at 80 FR 12762 (March 11, 2015), effective October 1, 2015, paragraph (c)(1)(ii) is revised and paragraphs (c)(1)(iii) and (c)(1)(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.

* * * * *

■ 32. In § 195.120, the title 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).

* * * * *

■ 33. In § 195.214, as amended at 80 FR 12762 (March 11, 2015), effective October 1, 2015, 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.

* * * * *

■ 34. In § 195.222, as amended at 80 FR 12762 (March 11, 2015), effective October 1, 2015, 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]

■ 35. In § 195.248, the phrase ''100 feet (30 millimeters)'' is removed and replaced with the phrase ''100 feet (30.5 meters)'' in the table to paragraph (a).

■ 36. In § 195.446, revise paragraphs (b)(3) and (b)(4), add paragraph (b)(5), revise paragraphs (h)(4) and (h)(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 that includes both controllers and other individuals who would reasonably be expected to interact with controllers (control room personnel) during normal, abnormal or emergency situations.

* * * * *

■ 37. In § Section 195.452, paragraph (a)(4) is added, 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, cracks, and deformation anomalies including dents, gouges and grooves. 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, cracks, and deformation anomalies including dents, gouges and grooves. When performing an assessment using an In-Line Inspection tool, an operator must comply with § 195.591;

* * * * *

■ 38. Section 195.501 is revised to read as follows:

§ 195.501 Scope.

This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks as defined in § 195.503 on a pipeline facility.

■ 39. Section 195.503 is revised to read as follows:

§ 195.503 Definitions.

For purposes of this subpart the following definitions apply:

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(1) Indicate a condition exceeding design limits; or

(2) Result in a hazard(s) to persons, property, or the environment.

Adversely affects means a negative impact on the safety or integrity of the pipeline facilities.

Covered task means an activity identified by the operator that affects the safety or integrity of the pipeline facility. A covered task includes, but is not limited to, the performance of any operations, maintenance, construction or emergency response task

Direct and observe means the process where a qualified individual personally observes the work activities of an individual not qualified to perform a single covered task, and is able to take immediate corrective action when necessary.

*Emergency response task*s are those identified operations and maintenance covered tasks that could reasonably be expected to be performed during an emergency to return the pipeline facilities to a safe operating condition.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(1) Written examination;

(2) Oral examination;

(3) Work performance history review;

(4) Observation during;

(i) Performance on the job;

(ii) On the job training; or

(iii) Simulations; and

(5) Other forms of assessment

Knowledge, skills and abilities, as it applies to individuals performing a covered task, means that an individual can apply information to the performance of a covered task, has the ability to perform mental and physical activities developed or acquired through training, and has the mental and physical capacity to perform the covered task.

Qualified as it applies to an individual performing a covered task, means that an individual has been evaluated and can:

(1) Perform assigned covered tasks;

(2) Recognize and react to abnormal operating conditions that may be encountered while performing a particular covered task;

(3) Demonstrate technical knowledge required to perform the covered task, such as: Equipment selection, maintenance of equipment, calibration and proper operation of equipment, including variations that may be encountered in the covered task performance due to equipment and environmental differences;

(4) Demonstrate the technical skills required to perform the covered task, for example:

(i) Variations required in the covered task performance due to equipment and/or new operations differences or changes;

(ii) Variations required in covered task performance due to conditions or context differences (*e.g.,* hot work versus work on evacuated pipeline); and

(5) Meet the physical abilities required to perform the specific covered task (*e.g.,* color vision or hearing).

Safety or integrity means the reliable condition of a pipeline facility (operationally sound or having the ability to withstand stresses imposed) affected by any operation, maintenance or construction task, and/or an emergency response.

Significant changes means the following as it relates to operator qualification:

(1) Wholesale changes to the program;

(2) Change in evaluation methods (*i.e.* performance and written to written only);

(3) Increases in evaluation intervals (*i.e.* from 1 to 5 years); or

(4) Removal of covered tasks (not including combining covered tasks).

Span of control means the ratio of nonqualified to qualified individuals where the nonqualified individual may be directed and observed by a qualified individual when performing a covered task, with consideration to complexity of the covered task and the operational conditions when performing the covered task.

■ 40. Section 195.505, as amended at 80 FR 12762 (March 11, 2015), effective October 1, 2015, is revised to read as follows:

§ 195.505 Qualification program.

(a) *General.* An operator must have and follow a written operator qualification program that meets the requirements of paragraph (b) of this section for all pipelines regulated under part 195. The written program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) *Program requirements.* The operator qualification program must, at a minimum, include provisions to:

(1) Identify covered tasks;

(2) Complete the qualification of each individual performing a covered task prior to the individual performing the covered task;

(3)(i) Ensure through evaluation that each individual performing a covered task is qualified to perform the covered task provided that:

(A) Review of work performance history is not used as a sole evaluation method.

(B) Observation of on-the-job performance is not used as a sole method of evaluation. (ii) However, when on-the-job performance is used to complete an individual's competency for covered tasks, the operator qualification procedure must define the measures used to determine successful completion of the on-the-job performance evaluation.

(4) Allow any individual who is not qualified pursuant to this subpart to perform a covered task if directed and observed by a qualified individual within the limitations of the established span of control for the particular covered task;

(5) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in § 195.52;

(6) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(7) Establish and maintain a Management of Change program that will communicate changes that affect covered tasks to individuals performing those covered tasks;

(8) Identify all covered tasks and the intervals at which evaluation of an individual's qualifications is needed;

(9) Provide training to ensure that any individual performing a covered task has the necessary knowledge, skills, and abilities to perform the task in a manner that ensures the safety and integrity of the operator's pipeline facilities;

(10) Provide supplemental training for the individual when procedures and specifications are changed for the covered task;

(11) Establish the requirements to be an Evaluator, including the necessary training; and

(12) Develop and implement a process to measure the program's effectiveness in accordance with § 195.505

(c) *Changes.* An operator must notify the Administrator or a State agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. Notifications to PHMSA may be submitted by electronic mail to *InformationResourcesManager@dot.gov,* or by mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, New Jersey Avenue SE., Washington, DC 20590.

■ 41. Section 195.507 is revised to read as follows:

§ 195.507 Program effectiveness.

(a) *General.* The qualification program must include a written process to measure the program's effectiveness. An effective program minimizes human error caused by an individual's lack of knowledge, skills and abilities (KSAs) to perform covered tasks. An operator must conduct the program effectiveness review once each calendar year not to exceed 15 months.

(b) *Process.* The process to measure program effectiveness must:

(1) Evaluate if the qualification program is being implemented and executed as written; and

(2) Establish provisions to amend the program to include any changes necessary to address the findings of the program effectiveness review.

(c) *Measures.* The operator must develop program measures to determine the effectiveness of the qualification program. The operator must, at a minimum, include and use the following measures to evaluate the effectiveness of the program.

(1) Number of occurrences caused by any individual whose performance of a covered task(s) adversely affected the safety or integrity of the pipeline due to any of the following deficiencies:

(i) Evaluation was not conducted properly;

(ii) KSAs for the specific covered task(s) were not adequately determined;

(iii) Training was not adequate for the specific covered task(s);

(iv) Change made to a covered task or the KSAs was not adequately evaluated for necessary changes to training or evaluation;

(v) Change to a covered task(s) or the KSAs was not adequately communicated;

(vi) Individual failed to recognize an abnormal operating condition, whether it is task-specific or non-task specific, which occurs anywhere on the system;

(vii) Individual failed to take the appropriate action following the recognition of an abnormal operating condition (task-specific or non-task-specific) that occurs anywhere on the system;

(viii) Individual was not qualified;

(ix) Nonqualified individual was not being directed and observed by a qualified individual;

(x) Individual did not follow approved procedures and/or use approved equipment;

(xi) Span of control was not followed;

(xii) Evaluator or training did not follow program or meet requirements; or

(xiii) The qualified individual supervised more than one covered task at the time.

(2) [Reserved]

■ 42. Section 195.509 is revised to read as follows:

§ 195.509 Recordkeeping.

Each operator must maintain records that demonstrate compliance with this subpart.

(a) *Individual qualification records.* Individual qualification records must include at a minimum:

(1) Identification of qualified individual(s),

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification;

(4) Qualification method(s);

(5) Evaluation to recognize and react to an abnormal operating condition, whether it is task-specific or non-task-specific, which occurs anywhere on the system;

(6) Name of evaluator and date of evaluation; and

(7) Training required to support an individual's qualification or requalification.

(b) *Program records.* Program records must include, at a minimum, the following:

(1) Program effectiveness reviews;

(2) Program changes;

(3) List of program abnormal operating conditions;

(4) Program management of change notifications;

(5) Covered task list to include all task-specific and non-task specific covered tasks;

(6) Span of control ratios for each covered task:

(7) Reevaluation intervals for each covered task;

(8) Evaluations method(s) for each covered task; and

(9) Criteria and training for evaluators.

(c) *Retention period*—(i) *Individual qualification records.* An operator must maintain records of qualified individuals who performed covered tasks. Records supporting an individual's current qualification must be retained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks must be retained for a period of five years.

(ii) *Program records.* An operator must maintain records as required in paragraph (b) of this section for a period of five years.

■ 43. 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 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 of the pipe 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.

■ 44. 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 1163–2005, *Inline Inspection Systems Qualification Standard;* ANSI/ASNT ILI–PQ–2010, *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

■ 45. The authority citation for part 199 is revised to read as follows:

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

■ 47. 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 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.

(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.

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■ 47. 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.

* * * * *

■ 48. 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.

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■ 49. 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.

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■ 50. 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.

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■ 51. 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.

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(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.

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Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

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