Federal Register

Friday,

November 26, 2010

Part II

Department of Transportation

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, 193 et al.

Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements; Final Rule

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR 191, 192, 193 and 195

[Docket No. PHMSA–2008–0291; Amdt. Nos. 191–21; 192–115; 193–23; and 195–95]

RIN 2137–AE33

Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements

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

ACTION: Final rule.

SUMMARY: This final rule revises the Pipeline Safety Regulations to improve the reliability and utility of data collections from operators of natural gas pipelines, hazardous liquid pipelines, and liquefied natural gas (LNG) facilities. These revisions will enhance PHMSA's ability to understand, measure, and assess the performance of individual operators and industry as a whole; integrate pipeline safety data to allow a more thorough, rigorous, and comprehensive understanding and assessment of risk; and expand and simplify existing electronic reporting by operators. These revisions will improve both the data and the analyses PHMSA and others rely on to make critical, safety-related decisions, and will facilitate both PHMSA's and states' allocation of pipeline safety program inspection and other resources based on a more accurate accounting of risk.

DATES: This final rule is effective January 1, 2011.

FOR FURTHER INFORMATION CONTACT: Roger Little by telephone at 202–366–4569 or by electronic mail at *roger.little@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On July 2, 2009, (74 FR 31675) PHMSA published a Notice of Proposed Rulemaking proposing to revise the Pipeline Safety Regulations (49 CFR Parts 190–199) to improve the reliability and utility of data collections from operators of natural gas pipelines, hazardous liquid pipelines, and LNG facilities. Specifically, PHMSA proposed the following amendments to the regulations:

1. Modify 49 CFR 191.1 to reflect the changes made to the definition of gas gathering lines in Part 192.
2. Change the definition of an "incident" in 49 CFR 191.3 to require an operator to report an explosion or fire not intentionally set by the operator and to establish a volumetric basis for reporting unexpected or unintentional gas loss.
3. Require operators to report and file data electronically whenever possible.
4. Require operators of LNG facilities to submit incident and annual reports.
5. Create and require participation in a National Registry of Pipeline and LNG Operators.
6. Require operators to use a standard form in electronically submitting Safety-Related Condition Reports and Offshore Pipeline Condition Reports.
7. Merge the natural gas transmission IM Semi-Annual Performance Measures Report with the annual reports. Revise the leak cause categories listed in the annual report to include those nine categories listed in ASME B31.8S. Expand information on the natural gas transmission annual report to add information for miles of gathering lines by Type A and Type B gathering, class location information by specified minimum yield strength (SMYS), volume of commodity transported, and type of commodity transported.
8. Modify hazardous liquid operator telephonic notification of accidents to require operators to have and use a procedure to calculate and report a reasonable initial estimate of released product and to provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response phase.
9. Require operators of hazardous liquid pipelines to submit pipeline information by state on the annual report for hazardous liquid pipelines.
10. Remove obsolete provisions that would conflict with the proposal to require electronic submission of all reports.
11. Update Office of Management and Budget (OMB) control numbers assigned to information collections.

The statutory authority under 49 U.S.C. 60101 *et seq.* authorizes this final rule; these Federal Pipeline Safety Laws grant broad authority to PHMSA to regulate pipeline safety. The proposed data collection and filing requirement revisions are wholly consistent with Section 15 of the PIPES Act of 2006 (Pub. L. 109–468, December 26, 2006), which requires PHMSA to review and modify the incident reporting criteria as appropriate to ensure that the data accurately reflects trends over time.

For natural gas pipeline operators, specific reporting requirements in 49 CFR Part 191 are found at:

- § 191.5 Telephonic notice of certain incidents.
- § 191.7 Addresses for written reports.
- § 191.9 Natural gas distribution incident report.
- § 191.11 Natural gas distribution annual report.
- § 191.15 Natural gas transmission and gathering incident report.
- § 191.17 Natural gas transmission and gathering annual report.
- § 191.23 Reporting safety-related conditions.
- § 191.25 Filing safety-related condition reports.
- § 191.27 Filing offshore pipeline condition reports.

The requirement for reporting leaks and spills of LNG in accordance with Part 191 is found at § 193.2011. Part 191 has excluded LNG from many of the reporting requirements.

For hazardous liquid pipeline operators specific reporting requirements in 49 CFR Part 195 are found at:

- § 195.48 Scope.
- § 195.49 Annual report.
- § 195.50 Reporting accidents.
- § 195.52 Telephonic notice of certain accidents.
- § 195.54 Accident reports.
- § 195.55 Reporting safety-related conditions.
- § 195.56 Filing safety-related condition reports.
- § 195.57 Filing offshore pipeline condition reports.
- § 195.58 Address for written reports.

As the Nation's repository for pipeline data, PHMSA's data is used not only by PHMSA, but by state pipeline safety programs, congressional committees, metropolitan planners, civic associations and other local community groups, pipeline research organizations, industry safety experts, industry watch groups, the media, the public, industry trade association, industry consultants, and members of the pipeline and energy industries. A significant amount of critical safety information is cultivated from PHMSA's data through statistical analysis and information retrieval. One of the agency's most valued assets is the data it collects, maintains, and analyzes pertaining to the industry. PHMSA is responsible for maintaining the most comprehensive collection of accident/incident data for intrastate and interstate pipelines in the country. PHMSA is subject to continual interest and scrutiny by numerous and varied stakeholders for the reliability, utility, and applicability of information and statistics pertaining to pipelines and LNG facilities, including the collection, tracking, and retrieval of historical data. PHMSA, therefore, must periodically modify its information and data collections and associated processes to address changes in industry business practices, changes in PHMSA's regulations, and changes in PHMSA's own data analysis strategies and objectives.

This rule also responds to various Government Accountability Office (GAO) and National Transportation Safety Board (NTSB) recommendations. In GAO's report titled: "Natural Gas Pipeline Safety: IM Benefits Public Safety, but Consistency of Performance Measure Should Be Improved," (GAO–06–946, September, 2006), GAO stated that the current gas incident reporting requirements do not adjust for the changing cost of gas released in incidents. GAO recommended that PHMSA "revise the definition of a reportable incident to consider changes in the price of natural gas." In the same report, GAO also recommended PHMSA revise reporting of performance measures for the IM programs to measure the impact of the program. GAO recommended that PHMSA improve the measures related to incidents, leaks, and failures to compare performance over time and make the measures more consistent with other pipeline safety measures.

The NTSB recommended that PHMSA modify 49 CFR 195.52 of the hazardous liquid pipeline regulations to require pipeline operators to have a procedure to calculate and provide a reasonable initial estimate of released product in their telephonic reports to the NRC (NTSB Safety Recommendation P–07–07). NTSB also recommended that the hazardous liquid regulations require pipeline operators to provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response (NTSB Safety Recommendation P–07–08). This rule includes provisions addressing these recommendations.

Section 15 of the PIPES Act of 2006 (Pub. L. 109–468, December 26, 2006) requires PHMSA to review and modify the incident reporting criteria to ensure that the data accurately reflects trends over time. One of the goals of this rulemaking is to comply with the requirements of this mandate.

In 2009, PHMSA revised the incident/accident report forms for gas transmission, gas distribution and hazardous liquid pipelines (August 17, 2009; 74 FR 41496). The use of these new forms were required beginning on January 1, 2010. The revisions to these forms were intended to make the information collected more useful to all those concerned with pipeline safety and to provide additional, and in some instances, more detailed data for use in the development and enforcement of its risk-based regulatory program.

II. Analysis of Public Comments

PHMSA received comments from 37 organizations including:

- Eight associations representing pipeline operators (trade associations).
- Fourteen gas distribution pipeline operators, many of which also operate small amounts of transmission pipeline as part of their pipeline systems.
- Five gas transmission pipeline operators.
- Two LNG facility operators.
- One operator of both gas transmission and hazardous liquid pipelines.
- The National Association of State Pipeline Safety Representatives.
- Two state pipeline regulatory authorities.
- Two pipeline service vendors.
- One standards developing organization.
- One citizens group.

Most commenters supported PHMSA's proposal to improve its data collection, although many expressed concerns over specific aspects of the proposal. This section addresses general comments regarding PHMSA's approach. We address comments related to specific changes proposed in the NPRM and on related proposed reporting forms individually, below:

General Comments

Stability and Consistency

A number of comments addressed stability and consistency in reporting and data collection. Southwest Gas Corporation (SWGas), Paiute Pipeline Company (Paiute), and TransCanada noted that PHMSA was revising incident report forms not affected by the changes proposed in this NPRM concurrently but in a separate docket. These commenters suggested that the dockets be combined or that PHMSA delay changes to the incident report forms until this proceeding was concluded. SWGas and Paiute also suggested that all data-collection changes should be considered in light of their potential impact on other PHMSA regulatory initiatives, such as control room management and IM for distribution pipelines. SWGas and Paiute also suggested that cause categories (*e.g.,* for leaks, incidents) should be consistent across all reports and that PHMSA should convene working groups to agree on categories and the minimal set of data needed. They contended that PHMSA's proposal would involve collection of more data than it will ever use. Piedmont Natural Gas Company (Piedmont) also requested that causes be made consistent between transmission and distribution, noting that it is burdensome to track causes differently for each pipeline type. Distrigas of Massachusetts LLC (DOMAC) suggested that PHMSA and the Federal Energy Regulatory Commission (FERC) meet to reconcile inconsistencies in reporting for facilities over which both agencies exercise jurisdiction, noting that such a meeting was contemplated in the 1993 Memorandum of Understanding between the agencies but has never occurred. National Grid requested that PHMSA make reporting changes once and minimize subsequent changes because change is very costly to implement and requires an operator to modify its management systems for collecting data.

Response

PHMSA recognizes that changes in reporting requirements necessitate a change in an operator's procedures and practices and that these changes should be infrequent. PHMSA also must change its data management systems when different data is reported. Yet, good data is necessary for PHMSA to understand the state of pipeline safety and to identify areas where additional regulatory attention may be needed. PHMSA is updating all of its data collection/management and reporting requirements so that it has the data that it needs to advance as a data-driven organization. PHMSA acknowledges that the changes made in this final rule, and to the incident/accident forms, will require the reporting of more data. PHMSA is making every effort to assure that the outcome of this rulemaking will minimize the need for any future changes. PHMSA is coordinating all of the activities related to data collection and does not believe that it is necessary to combine dockets. PHMSA is trying to establish consistent use of cause categories across all types of reporting and is considering its data collection needs, and the effect of its data gathering requirements, in light of its other regulatory initiatives.

PHMSA does not consider that a meeting with FERC to reconcile any differences in reporting is necessary at this time. While FERC and PHMSA share jurisdiction over some LNG facilities, there are many LNG facilities subject to PHMSA's regulations over which FERC exercises no jurisdiction.

Implementation

The AGA, Northeast Gas Association (NEGas), Oklahoma Independent Petroleum Association (OKIPA) and five pipeline operators requested that PHMSA allow time for data collection processes, databases, and software to be modified before new forms are implemented. Some suggested allowing one year after the effective date of the final rule. OKIPA requested 18 months. SWGas and Paiute suggested that one full calendar year of data collection should be allowed before new forms are used. TransCanada suggested PHMSA conduct a 90-day trial and begin use of new forms at the beginning of the calendar year following the end of the trial, with no retroactive reporting. They asserted that this kind of approach is needed to make sure the system works and that retroactive reporting would be unnecessarily redundant and confusing.

Response

PHMSA recognizes that it will take time for operators to revise their internal data management and collection systems and processes to report newly-required information. At the same time, excessive delay only postpones PHMSA's ability to use new data to understand better the state of pipeline safety. PHMSA does not consider that any of the information required in the revised forms is new. Pipeline operators already collect this information. Changes to internal processes may, indeed, make it easier to organize and report this data, but PHMSA does not believe that any retroactive data gathering will be required to complete the new annual report forms. The industry has been aware for some time that changes of this nature were in development. As discussed above, PHMSA needs better data to judge the effectiveness of its regulatory activities and to make informed decisions about future activities. Further postponement will only delay PHMSA's ability to use better data. Operators will therefore be required to use the new annual report forms in 2011 to report data for 2010. The information required to complete the new LNG incident report form is related to the occurrence of an incident and is collected during investigation of the event, not over time. Thus, the rule requires that the new form be used as soon as it is approved. However, in order to develop its on-line systems, PHMSA is delaying the submission of the 2010 annual reports for gas transmission, LNG and hazardous liquids. For the reporting year 2010, the gas transmission annual report and the LNG annual report will not be required to be submitted until June 15th and the hazardous liquid annual report will not be required to be submitted until August 15, 2011. In addition, we are delaying the implementation of the OPID registry requirements until January 1, 2012.

Additional Comment Opportunity

The Gas Piping Technology Committee (GPTC) and the Pipeline Safety Trust (PST) suggested that PHMSA allow a second opportunity for public comment. They noted that many changes were proposed in the NPRM and that many issues remain to be unresolved. They also noted there are significant changes to the related reporting forms.

Response

PHMSA believes adequate time has been given for comment and that an additional comment period is not needed. PHMSA considers that the issues have been well vetted through discussions with industry data groups, the comments discussed in this notice, and discussion at the December 2009 public meeting of the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee.

As discussed below, PHMSA is withdrawing the proposed new safety-related condition report form.

Organization of Regulatory Reporting Requirements

AGA, GPTC, DOMAC, and seven pipeline operators suggested that reporting requirements for gas pipelines and LNG facilities should be integrated into 49 CFR Parts 192 and 193 respectively. At present, reporting requirements for gas pipelines and LNG facilities are consolidated in Part 191 while the technical safety requirements applicable to these facilities are in Parts 192 and 193. For hazardous liquid pipelines, reporting and technical requirements are both in Part 195. Commenters suggested that relocation of the gas/LNG reporting requirements would improve clarity. DOMAC suggested it would be clearer for LNG facility operators given that the definitions in Part 193 are more specific to LNG—definitions in Part 191 are focused more on gas pipelines and can create confusion for LNG operators. SWGas and Paiute similarly commented that they consider LNG facilities to have unique characteristics that do not fit a pipeline-based reporting scheme. The other commenters also suggested that future changes would be facilitated and questioned why there is a different approach in the regulations for gas/LNG than for hazardous liquid pipelines.

Response

PHMSA did not propose any changes in how the pipeline safety reporting requirements should be organized. Thus, changes to incorporate Part 191 reporting requirements into Parts 192 and 193 are beyond the scope of this rulemaking. PHMSA will consider if it should undertake a future rulemaking to make these changes.

Risk-Based Regulation

Some commenters questioned whether the proposed changes reflect a risk-based approach. Technology and Management Systems, Inc. (TMS) noted that risk-based regulation would require consideration of both probability and consequences and standards that establish criteria on a risk basis. TMS also suggested that PHMSA should collect time and total volume of product flow between incidents, asserting that this data is needed for a true consideration of risk. DOMAC also suggested that throughput data be collected from all sectors on annual reports to provide a context for analysis of safety over time.

Response

PHMSA recognizes that a determination of risk involves consideration of both probability and consequence. Many of PHMSA's recent regulatory changes, particularly our IM initiatives, have been directed at managing risk, and these initiatives involve consideration of both the probability of an adverse event occurring and its potential consequences. PHMSA also recognizes that true "risk-based" regulation would involve standards expressed in terms of numerical thresholds related to risk. PHMSA does not consider such an approach practical for regulation of pipeline safety at this time.

PHMSA does not agree that collecting information on time and volume of product flow between incidents would serve PHMSA's needs or provide a better analysis of risk. Similarly, additional data concerning product throughput is not needed. Overall information on product movement is available from data PHMSA and the Energy Information Administration collect on annual reports, and this information can be used to understand the context in which pipeline incidents occur.

Definitions and Terminology

Some commenters requested that PHMSA add definitions for terms not now formally defined in the regulations. PST suggested adding definitions to Part 191 for gas pipeline facility/facilities, LNG plant, production facility, distribution pipeline system, gathering pipelines, and transmission pipelines, noting that these terms are used in the part but not now defined. DOMAC requested that the regulations refer to an "LNG facility" rather than an "LNG plant or facility," because the regulations only define the term facility. El Paso Pipeline Group (El Paso) suggested that terms be defined as needed, particularly the term "explosion." SWGas and Paiute recommended clarifying use of the term "significant," noting that the regulatory analysis supporting the NPRM used this term to describe events using the same criteria as those defining accidents in § 195.50. El Paso suggested that the references to "subchapter" in proposed § 192.945 be revised to refer to "part" as found elsewhere in the regulations.

Response

In the NPRM, PHMSA did not propose to add the definitions suggested by PST to Part 191. PHMSA cannot now add definitions in the final rule without having allowed an opportunity for public comment. PHMSA notes that many of the terms are defined in Parts 192 and 193 and are thus commonly understood within the pipeline industry. PHMSA does not consider the lack of these definitions in Part 191 to be a cause of confusion. PHMSA will consider if future rulemaking is needed to define additional terms in Part 191.

PHMSA does not consider that all terms used in the pipeline safety regulations must be defined explicitly. Terms require definition when they have particular meanings within the regulations. Terms that are used that reflect their commonly understood meaning need not be defined explicitly. As such, PHMSA does not think it is necessary to define "LNG plant" or to refer only to an "LNG facility" because that term is defined in Part 193. The use of "plant" to describe an industrial facility is common within the English language and does not need an explicit definition.

PHMSA also does not find it necessary to define the term "explosion." Although there are accepted technical definitions for this term, many involve factors, such as consideration of the magnitude of the resulting pressure wave that would require data not normally available for a pipeline event. At the same time, PHMSA considers that the difference between "ignites" (or burns) and "explodes" is commonly understood, and that reliance on this common understanding results in less confusion than would result from trying to apply a formal definition.

With respect to the term "significant," that term was used in the regulatory analysis to differentiate events that require reporting as accidents from events of lesser importance. It was not intended to reflect any more-important subset of reported incidents/accidents. Regulatory evaluations are prepared to explain the basis and benefits of proposed regulatory changes to all stakeholders, including those not directly involved in the regulated industry. It is thus necessary to reflect that not all adverse events that occur at a pipeline facility are reported as incidents, only those that are significant.

Proposed § 192.945 included two references to other sections of the pipeline safety regulations, one of which is in another Part (Part 191). Therefore, we must use "of this subchapter" for that reference. The other reference to § 192.7 should be referred to as "of this part." PHMSA has revised this section accordingly.

Miscellaneous

PST opposes the use of the National Pipeline Mapping System (NPMS) to collect data if information will not be available to the public via that system.

El Paso and Spectra Energy Transmission LLC (Spectra) requested that PHMSA encourage all stakeholders to make use of the reported data. They noted that they currently answer many telephone calls from PHMSA and state pipeline safety regulatory personnel seeking information that this proposed rule would require be reported.

OKIPA requested that PHMSA provide examples of significant information that would require a supplemental incident report under § 191.15(c).

Response

PHMSA does not intend to use NPMS to gather data proposed for the annual reports. As we noted, PHMSA is redesigning its own information management systems. These changes will make information more readily available to PHMSA and state regulatory personnel. PHMSA will encourage its staff to obtain information from the PHMSA systems rather than telephoning operators.

Section 191.15(c) does not require a supplemental report for "significant" information, and thus no examples are necessary to illustrate significance. This paragraph requires a supplemental incident report when additional information becomes known after an initial incident report is submitted. This could include information necessary to complete a section of the incident report form that was left blank in the initial submission because the information was not yet known. It could also include additional information that the operator concludes is important to understanding the incident and which the operator would report in the narrative section of the form.

III. Discussion of Public Comments on Individual Issues

(1) Modifying the Scope of Part 191 To Reflect the Change to the Definition of Gas Gathering Lines

49 CFR 191.1

Proposal

In the NPRM, PHMSA proposed to revise the scope of Part 191 to address an inadvertent omission in the March 15, 2006, final rule that redefined the definition of gas gathering pipelines in Part 192. Part of that rulemaking effort revised § 192.1 to reflect the change in the scope of Part 192. A corresponding change was not made to the scope of Part 191, which specifies requirements for reporting incidents and other events and for submission of annual reports by operators of pipelines subject to Part 192. Because of this omission, there was confusion whether operators of gathering lines that became regulated only with the 2006 rule were required to submit reports. Further, operators of gathering lines have been reporting the number of miles of gas gathering lines by the old definition and not by the new definition in Part 192.

Comments

The Texas Oil and Gas Association (TXOGA) and Atmos Energy Corporation (Atmos) suggested clarifying § 191.15, requiring submission of incident reports, and § 191.17, requiring annual reports, to indicate that they apply only to regulated gathering lines.

The National Association of Pipeline Safety Representatives, supported by the Iowa Utilities Board (IUB), suggested PHMSA require operators of all gathering lines to report incidents, regardless of whether they are regulated under Part 192. The commenters noted that data on incidents that occur on non-regulated lines is necessary to determine whether additional regulation is needed.

Response

PHMSA has not changed the proposed regulatory language. Section 191.1(b)(4)(ii), as revised in this final rule, clearly states that Part 191 does not apply to gathering lines that are not regulated gathering lines as determined in accordance with § 192.8. Thus, none of the provisions in Part 191, including §§ 191.15 and 191.17, applies to non-regulated gathering lines. The clarification TXOGA and Atmos requested is not needed.

PHMSA agrees that data for incidents that occur on non-regulated gathering lines could be useful in determining whether these pipelines should be brought under the reporting regulations. However, PHMSA did not propose such a change. PHMSA would have to undertake a new rulemaking to bring unregulated gathering lines under Part 191 incident reporting requirements.

(2) Changing the Definition of an "Incident" for Gas Pipelines

49 CFR 191.3

Proposal

In the NPRM, PHMSA proposed to change the definition of an incident in 49 CFR 191.3 to establish a new reporting category: An explosion or fire not intentionally set by the operator. This proposed change would make the definition consistent with the accident reporting criteria for hazardous liquid pipelines in Part 195.

The NPRM also proposed to establish a volumetric basis of 3,000 Mcf (the abbreviation "Mcf" means thousand cubic feet) for reporting unintentional gas loss. This proposal responded to a GAO recommendation. In a report titled: "Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measure Should Be Improved," (GAO–06–946, September, 2006), GAO stated that the current gas incident reporting requirements do not adjust for the changing cost of gas released in incidents. GAO recommended that PHMSA "revise the definition of a reportable incident to consider changes in the price of natural gas."

In November 2005, the Interstate Natural Gas Association of America (INGAA) submitted a petition for rulemaking recommending PHMSA adopt a volume basis instead of the cost of gas lost. INGAA recommended 20 million standard cubic feet as a reporting threshold. INGAA based this volume on the $50,000 reporting threshold and the 1985 [1] cost of gas at $2.50 per Mcf.

The proposed change responded to both the GAO recommendation and the INGAA petition. It would remove the cost of gas lost from consideration in determining whether an event constitutes an incident under the existing criterion of $50,000 damage. This would correct the problem GAO identified in that the volatility of gas prices would no longer be an issue in determining whether a particular event met the definition of an incident. The new criterion would separately capture events in which a large quantity of gas is lost regardless of the value of resulting property damage.

The proposal also changed the language preceding the criteria to make clear that an incident was an event that resulted in one of the listed consequences. Previously, the regulations referred only to events that "involve[d]" one of the consequences and it was not clear that events of interest were those in which the gas pipeline failure resulted in the listed consequences.

Comments

Causality

INGAA, the Texas Pipeline Association (TPA), TransCanada, and NiSource Gas Transmission and Storage (NiSource) supported the change to make it clear that events only become incidents if the listed consequences resulted from a release of gas from a pipeline. DOMAC and National Grid disagreed, noting that conclusions of causality could imply legal liability, and expressing a preference for the former structure of reporting events that "involve" stated consequences to avoid pre-judging liability.

Explosion or Fire Not Intentionally Set by the Operator

AGA, the American Public Gas Association (APGA), GPTC, NAPSR, IUB, and many pipeline operators objected to the addition of this criterion. Many of these comments reflected confusion about fires that did not result from the gas pipeline failure. Commenters noted, for example, that over 400,000 structure fires occur each year in the U.S. In many of those fires, a gas meter is damaged and gas subsequently becomes involved in the pre-existing fire. These commenters maintained that PHMSA has no jurisdiction over fires that begin from non-pipeline causes and that reporting these events as pipeline incidents would significantly misrepresent pipeline safety and would distort current incident trends. They also asserted that other agencies (*e.g.,* Federal Emergency Management Agency) already collect fire data.

GPTC and several operators commented that a brief "fire" is an expected operational event during many activities associated with operation and maintenance of gas distribution pipelines. DOMAC claimed, for example, that the proposed criterion would require reporting of a lightning strike that ignites a gas relief vent that is designed to close and snuff out the resulting fire with no safety consequences. APGA argued that this criterion could significantly increase the number of "incidents" and that PHMSA had not considered the significant burden that could result due to existing requirements to test personnel involved in an incident for drugs and alcohol. Some commenters also objected that analyses referred to in the NPRM in support of this proposed new criterion were not included in the docket for public examination. Several pipeline operators suggested that the new criterion was not needed since the remaining criteria would provide a complete picture of consequential events.

INGAA, El Paso, and Spectra took a contrary position and suggested that the proposed new criterion apply to events resulting from intentional and unintentional releases of gas.

IUB suggested that we should not exclude fires intentionally set by an operator because hazardous liquid pipeline operators sometimes intentionally set fires to consume released product that cannot otherwise be recovered.

AGA commented that nearby fires should be deleted as a primary cause of a gas pipeline incident because these are outside PHMSA jurisdiction.

Volume Measure for Released Gas

AGA, NAPSR, IUB, and several pipeline operators questioned the practicality of the proposed criterion. AGA and several pipeline operators noted the difficulty in calculating the amount of a release within two hours, by which time a telephonic report of an incident is expected. They contended that factors necessary for this analysis are not readily obvious. IUB, Atmos, and Michigan Consolidated Gas (MichCon) questioned the applicability of this criterion to distribution pipeline incidents. They noted that property damage is the predominant component of costs for distribution incidents, and that the concern expressed by INGAA and others that increases in the cost of gas (and resulting increase in the calculated cost of gas lost) strongly influence the determination of whether an event constitutes an incident generally is not applicable to distribution pipeline events. They also noted that it is sometimes difficult to calculate the amount of gas lost in distribution events. SWGas and Paiute,

[1] The criterion for reporting property damage exceeding $50,000 was established in 1984 and began widespread use in 1985.

distribution and transmission pipeline operators respectively, agreed, stating that the volume of gas lost was usually ancillary to other reporting criteria. Baltimore Gas & Electric (BG&E) suggested eliminating or qualifying this criterion to apply only to unintended releases. BG&E contended that release of gas is a routine part of doing business and classifying such events as incidents could distort safety trends.

Most commenters questioned the size of the proposed criterion. Many noted that it was incorrectly stated in the proposed rule language as 3,000 million cubic feet, although the preamble discussion described the proposed amount as 3,000 Mcf. The industry trade associations and many operators argued that the proposed magnitude of the criterion is too small and that 3,000 Mcf is inconsistent with a criterion of $50,000 in property damage. INGAA suggested that the release criterion should be 20,000 Mcf. Other commenters suggested different values, varying between 10,000 and 20,000 Mcf. Northern Natural Gas (Northern) and Spectra (gas transmission pipeline operators) suggested that it would be appropriate to establish different criteria for gas transmission and distribution pipelines.

INGAA and several pipeline operators requested clarification concerning how the proposed criterion was to be applied. El Paso and Spectra contended that intentional releases, including from appurtenances designed to release gas (*e.g.,* relief valves) should not require reporting because these are not consequential incidents. These operators also suggested that the criterion not be applied to small leaks that might release large quantities of gas over an extended period. Similarly, NiSource commented that the criterion should only apply to immediate releases resulting from an event and should exclude subsequent blowdowns which have no significant effect on public safety. INGAA, El Paso, and TransCanada also suggested that the criterion be limited to gas lost at the incident location because gas lost at controlled locations (such as would be used for blowdowns) does not pose the same risk.

The industry trade associations and several operators also requested that PHMSA make clear that the introduction of this new criterion means that the cost of gas lost will no longer be used in determining whether an event constitutes an incident because of $50,000 in property damage costs. PST also requested clarification in this area. IUB suggested that PHMSA should provide guidance on how the amount of gas lost is to be calculated.

Property Damage Criterion

AGA and a number of pipeline operators commented that the existing criterion of $50,000 property damage is too low and should be raised. The commenters noted that this criterion was established in 1984 and has not been adjusted since; inflation has made events reportable that would not have been reportable in 1984. Commenters suggested that the criterion should be increased to $100,000, that it should be revised periodically or indexed for inflation, or that various categories of costs should be excluded from consideration. Contrary to this general trend, SWGas and Paiute suggested that all costs, including third-party damages and costs to relight customers, should be included, since these are costs directly related to the event.

Miscellaneous

PHMSA received several comments related to the definition of a gas pipeline incident that did not fit into the categories discussed above. MidAmerican, a gas distribution pipeline operator, suggested not to change the definition because the proposed changes would add events of little or no safety significance and divert resources from safety. The Missouri Public Service Commission (MOPSC) suggested revising the existing criterion related to injuries to include medical care at an emergency room or other facility in addition to inpatient hospitalization. MOPSC contended that changes in the practice of medicine have resulted in many injuries that formerly required inpatient hospitalization now being treated at such facilities. INGAA, NAPSR, Northern, Atmos, and TransCanada commented that incidents should be limited to unintentional releases of gas). MOPSC suggested that the definition not be limited to releases "from a pipeline," given that consequential events can result from releases at other locations (*e.g.,* fuel lines). AGA and BG&E noted that it is impractical to make incident criteria the same for hazardous liquids and natural gas because there are fundamental differences between hazardous liquid and gas pipelines, particularly gas distribution pipelines.

Response

Causality

PHMSA is sensitive to the potential legal issue raised by DOMAC and National Grid. PHMSA understands that an initial conclusion that a pipeline event "resulted in" certain consequences may differ from a legal finding that the pipeline event caused those consequences, resulting in liability. Still, PHMSA concludes that it is important to consider causality in reporting incidents.

PHMSA's mission is to protect public health and safety and the environment from risks associated with transporting hazardous materials by pipeline. PHMSA's concern in requiring the reporting of incidents is that it understands fully the extent to which problems on regulated pipelines result in adverse impacts on safety and the environment. Accordingly, PHMSA's analyses of its incident data always assume a degree of causality between the pipeline failure and the reported consequences. It is therefore important that this data be collected so that it is limited to those events in which a pipeline failure resulted in adverse consequences, rather than instances in which the event happened to occur concurrently with circumstances that meet one of the criteria defining an incident (*i.e.,* death, injury, or property damage exceeding the reporting threshold). PHMSA is thus persuaded that the incident definition in § 191.3 should require a conclusion of a degree of causality (which does not imply legal liability).

Causality has been treated in the § 195.50 requirement for accident reports for hazardous liquid pipelines for many years. Hazardous liquid operators have not complained to PHMSA that this treatment has adversely affected them in any liability proceedings. PHMSA has accepted the suggestion to conform the treatment of incidents in Part 191 to that of accidents in Part 195; therefore, this final rule defines a gas pipeline incident as "a release of gas from a pipeline, or of LNG, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:".

Explosion or Fire Not Intentionally Set by the Operator

PHMSA has not included in this final rule the proposed new criterion concerning fires or explosions not intentionally set by the operator. PHMSA is persuaded by the comments that it did not adequately consider the effect of this new criterion and the resulting burden. In addition, as discussed above, PHMSA has revised the definition of an incident in § 191.3 to include an implied causal relationship between a pipeline failure and one of the listed consequential events. PHMSA concludes that these changes will eliminate the perceived need to report the vast majority of events in which a fire existed before the gas pipeline failure (so-called "fire first" events).

At the same time, PHMSA does not agree that no "fire first" events should be considered. PHMSA considers the argument that it lacks jurisdiction over fires not resulting from pipeline failures to be irrelevant. PHMSA also lacks jurisdiction over excavation near pipelines or over severe weather events (*e.g.,* hurricanes), both of which often result in pipeline incidents. PHMSA has a responsibility to assure that the pipeline facilities over which it has jurisdiction are adequately protected from events, including excavation, hurricanes, and nearby fires, that could cause safety-significant problems in those facilities regardless of whether it has jurisdiction over the events themselves. PHMSA collects incident data, in large part, to assure that this protection is adequate or to identify instances in which additional regulation is required to assure adequate protection.

As part of a separate proceeding involving changes to incident/accident reporting forms, PHMSA has revised the form's instructions to clarify that secondary ignition events—those events where the fire exists first and subsequently results in damage to pipeline facilities—need only be reported if the damage to pipeline facilities exceeds $50,000 (one of the incident-defining criteria in this rule). This provision was included in incident reporting instructions prior to a form change in 2004. A NAPSR resolution, included as an attachment to its comments filed in this docket, sought restitution of this provision as its proposed solution to the problem posed by "fire first" events. PHMSA agrees. The changes in this final rule and to the reporting instructions should eliminate the need to report the vast majority of structure fires, since few structures are associated with pipeline facilities that could result in $50,000 damage (the value of a typical residential meter set is a few hundred dollars). The changes will result in reporting of significant pipeline failures caused by nearby fires (*e.g.,* forest fires), which are appropriate for PHMSA's consideration in the same manner as other events that cause pipeline incidents.

Volume Measure for Released Gas

PHMSA concludes that many of the comments regarding this criterion resulted from the relatively low volume proposed. This led to concerns about the need to report routine releases associated with operational events, such as leaks and blowdowns. PHMSA analyzed incident reporting from 2004 through 2009 to assess the impacts that a 3,000 Mcf vs. a 10,000 Mcf volumetric reporting threshold would have on incident reporting frequency. Both gas transmission and gas distribution incident reporting during that timeframe included the cost of gas lost, facilitating the comparison. The comparison indicates that at 10,000 Mcf, we would lose about 20 incident reports per year across both gas transmission and gas distribution incident reporting. Because the annual frequency is very low (about 135 gas transmission and about 150 gas distribution incidents annually), PHMSA believes that lowering the numbers further would adversely impact our ability to effectively conduct safety analysis and trending. Our analysis shows that at the 3,000 Mcf threshold, we estimate we would lose six incident reports per year. INGAA had suggested a threshold of 20,000 Mcf, an amount that corresponds to the amount of gas that would have cost $50,000 when the property damage threshold was revised in 1984. PHMSA agrees that relating the volume threshold to the property damage threshold is appropriate, but does not agree that this should be done on the basis of 1984 costs. Incidents are reported based on current costs. Absent this rule change, an event that resulted in loss of approximately 10,000 Mcf would be reportable as a loss of $50,000 of gas (considering current costs). However, as PHMSA concludes from a comparison of 10,000 Mcf to 3,000 Mcf as stated above, the impact of lowering the already low frequency of reporting further would impact safety trending capability, therefore, we have chosen to maintain the proposed 3,000 Mcf threshold for the volume release criterion. This final rule requires reporting of releases that meet or exceed "3 million cubic feet" (i.e., 3,000 Mcf). PHMSA recognizes that initial calculations are approximate, but does not consider this a reason not to report events that have consequence.

PHMSA recognizes that the amount of gas lost in distribution incidents is usually less than that for transmission pipelines. This means that there will likely be fewer events that are defined as incidents on distribution pipelines due to the volume of gas released if the same criterion is used for both types of pipelines. Nevertheless, PHMSA considers use of a common criterion appropriate. Distribution events more often become "incidents" due to the amount of property damage that occurs or as a result of death or injury. This reflects real differences between transmission and distribution pipelines. Using a different volume release criterion for distribution pipelines to force the number of reported incidents to be similar to that of transmission pipelines would distort analytical results and obscure these real differences.

PHMSA agrees that intentional, controlled releases are not events with significant safety consequences. PHMSA has revised the final rule to clarify that reporting under the volume threshold is only required for "unintended" releases that exceed the specified amount. Yet, PHMSA does not agree that other criteria should be limited to unintentional releases. PHMSA considers that an intentional release that results in death, inpatient hospitalization, or $50,000 in property damage would be an event with significant safety consequences and should be reported as an incident.

The intent of this new criterion is to separate lost gas from other property damage costs to preclude the volatility of gas prices from affecting which events are defined as incidents. PHMSA has revised the final rule to make clear that the cost of gas lost is not to be included in the calculation of property damages for comparison with the $50,000 criterion.

Property Damage Criterion

The NPRM did not include any change to the existing $50,000 property damage criterion. As such, changes to this criterion would be outside the scope of this rulemaking. However, PHMSA does believe that because the annual frequency of both gas distribution and gas transmission incident reporting is extremely low as noted above, a reevaluation of that threshold is appropriate and PHMSA may take that under consideration in the future.

Miscellaneous

PHMSA does not agree that the changes in the definition of a gas pipeline incident add events of little safety significance. As discussed above, these events are significant. PHMSA has made clarifications to eliminate reporting of non-consequential events (*e.g.,* intentional blowdowns and most "fire first" events). PHMSA does not consider that these changes will result in any inappropriate redirection of resources.

Similarly, PHMSA did not propose any change to the existing criterion for injury; therefore, MOPSC's suggested changes to this criterion would be outside the scope of this proceeding. PHMSA notes, however, that inpatient hospitalization is an objective criterion. Other treatment can vary based on local practices. In some areas, people with minor injuries may still be taken to emergency rooms as a precautionary measure, but those patients would not be admitted unless their injuries were serious. PHMSA considers the existing criterion appropriate.

PHMSA has discussed above its reasons for requiring reporting of events resulting from intentional releases of gas, excluding events that result solely in loss of gas, as incidents. Pipelines and pipeline facilities are PHMSA's focus of regulatory concern; therefore, PHMSA has not accepted MOPSC's suggestion to expand the scope of incidents beyond releases from these facilities.

PHMSA agrees that the criteria defining an incident for hazardous liquid and gas pipelines should recognize differences between those pipelines and the commodities they carry. As discussed above, PHMSA has decided not to include a criterion in the definition of a gas pipeline incident related to a fire not intentionally set by the operator or an explosion. Such a criterion has long been part of the definition of an accident for a hazardous liquid pipeline.

(3) Requiring Electronic Reporting and Filing of Reports

49 CFR 191.7 and 195.58

Proposal

In the NPRM, PHMSA proposed to require operators of a regulated pipeline or facility to submit all reports to PHMSA electronically. This proposal was intended to improve the processing of submitted reports and reduce paperwork burdens.

Comments

Most commenters supported electronic reporting, while APGA suggested retaining an option for paper filing for very small distribution operators that may lack internet access. GPTC noted that the proposed requirement to apply for non-electronic submission 60 days in advance of a report being due was inconsistent with the requirement to submit incident reports in 30 days. OKIPA requested that PHMSA describe the criteria it will use to review applications for non-electronic reporting and to assure consistency among states. PST objected to allowing an option for non-electronic reporting, noting that internet access is now widely available.

Many commenters addressed the process by which electronic reports will be made. The American Petroleum Institute (API) and the American Association of Oil Pipelines (AOPL) argued that electronic reporting should be more than completing a form on the computer; it should include internal checks to prevent incorrect entries, assure data consistency, etc. API and AOPL also suggested that a narrative description should continue to be part of incident reports. API, AOPL, AGA, GPTC, and several pipeline operators suggested that the on-line system allow for saving interim work and printing a completed form before submission. API, AOPL and Atmos proposed that the system allow for electronic submission of a completed template to save time and reduce potential for errors. Pipeline operators recommended that the on-line system allow users to print a blank form, provide electronic confirmation of submission, and provide clear guidance for updating/modifying/superseding reports in the event of new information. National Grid commented that controls should be established to allow submissions only by a company's designated representative. APGA, GPTC, and Northern Illinois Gas Company (Nicor) maintained that reports should not be considered late-filed if the on-line system is not available on the date on which a report submission is required.

Northern suggested that the on-line system should also allow a report to be rescinded electronically, which would be consistent with requiring electronic submissions and would be less burdensome. Piedmont advised that PHMSA should staff sufficiently to handle data correction requests based on their experience that it is difficult to correct data once submitted.

APGA, GPTC, and NiSource suggested revising the regulations to allow electronic submittal of reports that must be made immediately to the NRC, noting that the NRC system now provides for this alternate method.

API, AOPL, TPA, TXOGA, and Atmos commented that separate reports should not be required for interstate agents and states; instead current technology allows reports to be forwarded to the appropriate agency based on the location of assets involved.

Response

PHMSA agrees that a paper-filing option must be provided, although PHMSA expects that the need for alternate submission will be rare. At the same time, PHMSA is persuaded that its proposed option to apply for non-electronic filing was unduly burdensome. A requirement to request non-electronic reporting 60 days in advance is, as commenters noted, inconsistent with a requirement to report incidents in 30 days. In addition, requiring a request for non-electronic filing separately for each report unnecessarily adds burden for operators and PHMSA because the same few operators are likely to apply for approval repeatedly. PHMSA has revised the final rule to eliminate the requirement to request an alternate reporting method 60 days in advance of each required submission. The final rule provides that operators may apply for use of alternate submission methods and that approvals of such requests may be indefinite or until a date specified by PHMSA, eliminating the need to apply separately for each required submission. PHMSA will review the description of the undue burden that would be imposed by a requirement to file electronically but does not find it necessary or appropriate to define specific criteria for acceptance or denial at this time. The requirement for electronic submission, and for alternate methods, applies to submissions made to PHMSA; therefore, the question of consistency among states is not at issue here.

PHMSA's electronic reporting system includes the options commenters requested. This system is already being used for recently revised incident/accident report forms. The system includes internal checks for data consistency and incorrect entries (*e.g.,* entering text in a numeric field). It allows saving of work in progress and printing of completed or blank forms. Where forms are printed before submission, the word "DRAFT" appears as a diagonal watermark to avoid later confusion as to whether a filed copy represents information that was actually submitted. The incident reports provide for a narrative description. Confirmation of submission is provided by an electronic date stamp visible to both the submitting operator and PHMSA.

PHMSA has not allowed for submission of a completed template in lieu of entering the information on-line. On-line data entry provides for data quality checks that would not be possible with uploaded files. These controls are important to help reduce the need for data correction, and are expected to help address the difficulties with data correction raised by Piedmont.

Submissions are made using user identification and passwords that are provided to a company's designated person. PHMSA does not consider it necessary to modify further its on-line system to allow submission only by designated company representatives. Operators should control dissemination of their ID/password as they would for any password-protected computer system.

PHMSA has not adopted Northern's suggestion to allow reports to be rescinded electronically. Although this may be easier, rescissions need to be made through PHMSA's staff for data quality reasons.

PHMSA has eliminated requirements to file duplicate copies of reports with states with the exception of safety-related condition reports. PHMSA is required by statute (49 U.S.C. 60102(h)) to provide for concurrent notice of safety related conditions to appropriate State authorities.

As suggested by commenters, PHMSA has revised §§ 191.5 and 195.52 to allow operators the option of submitting on-line reports of certain incidents to the NRC (NRC). The NRC now allows for electronic reporting of incidents; therefore, including this option in PHMSA's regulations imposes no new burden on the regulated industry.

(4) Requiring LNG Operators To Submit Incident and Annual Reports

49 CFR 191.9, 191.15, 191.17 and 193.2011

Proposal

In the NPRM, PHMSA proposed to amend §§ 191.9, 191.15, 191.17, and 193.2011 to require LNG facility operators to submit annual and incident reports consistent with the current reporting requirements for gas and hazardous liquid pipeline operators. LNG facility operators had previously been exempted from these requirements.

Comments

SWGas and Paiute contended that submission of incident reports for LNG facilities is not needed because incidents at these facilities are very rare. BG&E and MidAmerican also maintained that annual reports are unnecessary because these facilities are static and the reported information will not change from year to year. SWGas and Paiute claimed that the need for annual reports to justify user fees is specious given that fees are currently determined by tank volume. These operators also contended that it was not possible to estimate the burden for completing the annual report forms since changes in which emergency shutdowns are to be reported could have a major impact on what needs to be reported. DOMAC also commented that information reported on incident reports (*e.g.,* emergency shutdowns) should not be repeated on annual reports. DOMAC maintained that PHMSA has not made a good case for the need for reporting by LNG facility operators and those problems in other sectors should not be the basis for requiring reporting by LNG operators. DOMAC suggested that PHMSA should convene an LNG data team to design forms to be used to report LNG incidents because the reporting proposal and related forms demonstrate a lack of knowledge of LNG facilities. DOMAC further suggested that facility data should be automatically populated on incident report forms from information available in the Pipeline and LNG Operators' Registry. SWGas and Paiute suggested that PHMSA should partner with FERC or states to get LNG information to eliminate duplicate reporting. These operators also claimed that a form is not needed for safety-related condition reports because such reports at LNG facilities are rare.

Other commenters raised concerns related to how the definition of an incident in § 191.3 apply to LNG facilities. A principal concern of these commenters was the proposed requirement that all emergency shutdowns be reported as incidents, except those resulting from maintenance. AGA, INGAA, NEGas, Northern, Northwest Natural Gas (NWN), BG&E, National Grid, and MidAmerican would all limit reporting to actual emergencies, noting that not all emergency shutdowns are safety-significant events. MidAmerican suggested that requiring such reports would discourage operators from installing aggressive emergency shutdown systems. DOMAC claimed that the exclusion for maintenance is unnecessary because the preamble of the 1984 rulemaking that required telephonic reporting of emergency shutdowns stated that only actual emergencies needed to be reported. DOMAC also maintained that the concept of a leak in piping and equipment is not applicable to an LNG facility. BG&E would similarly eliminate rollover events as not safety-significant. SWGas and Paiute would delete from the definition of an incident any reference to refrigerant gas because this is not gas in transportation and not subject to PHMSA's jurisdiction. Piedmont asked for clarification as to whether the volume release or explosion/fire criteria apply to LNG facilities.

SWGas and Paiute noted that use of some terms differs between pipelines and LNG facilities and that terms used for LNG need to be accurately defined.

NiSource Distribution Companies (NISource Distribution) suggested that because LNG is a "chemical of interest" for terrorist protection, PHMSA and the Department of Homeland Security should discuss what information is to be collected and made public.

Response

PHMSA is not persuaded that relative rarity of incidents at LNG facilities means that reports of these events are not needed. Such reports may be submitted rarely, but they will provide valuable data concerning safety-significant events and conditions that may occur. The existence of a reporting requirement or a related form will impose no burden on LNG operators that do not experience incidents. PHMSA agrees with DOMAC that it is not necessary to collect information on annual reports that are obtained via incident reports. PHMSA has omitted reports of emergency shutdowns from the annual report form, as these will be reported as incidents. (As discussed below, PHMSA is withdrawing the proposed safety-related condition report form at this time).

PHMSA recognizes that major changes occur infrequently at individual permanently-located LNG facilities. At the same time, some LNG facilities are temporary or mobile, and there has been unprecedented expansion in the number of LNG facilities. It is no longer practical for PHMSA to manage its oversight of LNG facilities based on recalled knowledge. Data is needed, and annual reports are the vehicle by which this data will be collected and kept current. PHMSA has designed its form and will design its on-line reporting to allow the operator of an individual LNG facility to indicate that data reported in the previous year has not changed, in which case the operator will not need to repeat the information. This will minimize the reporting burden for operators of facilities that do not experience changes.

PHMSA does not agree with DOMAC that the forms proposed for LNG reporting represent little knowledge of LNG facilities and systems. The proposed forms were based, in large part, on forms that have been used for reporting LNG events in the State of Texas for many years. PHMSA believes these forms are suitable for use, but PHMSA recognizes that these forms, as for any form, could likely be improved. PHMSA will consider DOMAC's proposal to convene an LNG data team to review the forms as a subsequent effort but does not consider it necessary to take this step before implementing a reporting requirement for LNG facilities.

PHMSA notes that problems in other sectors have not formed the basis for requiring reporting of LNG incidents. PHMSA has focused on LNG in this effort. The criteria defining significant consequences apply equally to LNG and to pipelines. An event that causes a death, serious injury, or significant property damage is significant whether it occurs on a pipeline or at an LNG facility. LNG emergency shutdowns have long existed as an incident-defining criterion. The change here is that PHMSA is now requiring written reports for LNG incidents that previously required only telephonic reports to NRC. This is part of PHMSA's increased data focus. PHMSA intends to base future actions on its analysis of data concerning actual safety performance. Additional data concerning LNG incidents, even if rare, is important to support this goal.

PHMSA has revised the definition of an incident in § 191.3 to clarify that actuation of an emergency shutdown system at an LNG facility that results from causes other than an actual emergency does not constitute an incident. This will eliminate the need to submit incident reports for shutdowns that result from maintenance, inadvertent actuations and signals, and any other emergency shutdown that does not result from an actual emergency. PHMSA has also deleted rollovers as an incident criterion. PHMSA agrees that these changes will focus reporting on events with safety significance. PHMSA doubts, however, that LNG operators would not install systems that aggressively protect their facility investment solely because of a requirement to report safety system actuations.

PHMSA has not deleted reference to a release of refrigerant gas. PHMSA acknowledges that this is not gas in transportation, but the facility in which it is used is regulated. Release of refrigerant gas could represent a failure within that facility. If that failure results in consequences significant enough to trigger one of the incident reporting criteria, then that event needs to be reported. The volume release criterion applies to LNG facilities, as modified, to include only unintentional gas loss. In response to comments, we have eliminated the proposed fire or explosion criterion.

PHMSA agrees with DOMAC that it would reduce operator burden, and likely improve data consistency/quality, if information in the Operator Identification (OPID) Registry was automatically populated into incident forms based on the entered OPID. At present however, the data that PHMSA has concerning OPIDs is not of sufficient quality to do so. This will change as operators validate the information (discussed below). PHMSA will consider a change to its on-line reporting system, once validation is completed, to implement the suggested change.

In response to comments about consistency in definitions of terms, PHMSA has made every effort to make the definitions in forms and instructions for LNG reporting accurate and consistent.

PHMSA regularly consults with the Department of Homeland Security regarding security concerns about data made available to the public. PHMSA will include LNG data in these discussions.

(5) Creating a National Registry of Pipeline and LNG Operators

49 CFR 191.22 and 195.64

Proposal

In the NPRM, PHMSA proposed to require all pipeline operators and LNG plant or LNG facility operators obtain an OPID from PHMSA. This proposal also would require operators to use this OPID for all submissions (NPMS, annual report, accident, incident, safety-related condition etc.) to PHMSA. PHMSA also proposed that an operator notify PHMSA at least 60 days in advance of certain profile or other changes to its facilities which could impact public safety. Such changes would have included any of the following activities for an existing or new pipeline, pipeline segment, pipeline facility, LNG plant, or LNG facility:

- A change in the operating entity responsible for operating an existing pipeline, pipeline segment, or facility.
- A change in the operating entity responsible for managing or administering a safety program (such as an IM or Corrosion Prevention Program) covering an existing pipeline, pipeline segment, or facility.
- The acquisition or divestiture of 50 or more miles of an existing regulated pipeline or pipeline segment.
- Any rehabilitation, replacement, modification, upgrade, uprate, or update costing $5 million or more.
- The construction of ten or more miles of a new hazardous liquid or gas transmission pipeline facility, or other construction project costing $5 million or more.
- The construction of a new LNG plant or LNG facility, or the sale or purchase of an existing LNG plant or LNG facility.

A National Registry of Pipeline and LNG Operators will serve as the storehouse for the reporting requirements for a regulated operator. Essential to the effectiveness of PHMSA's oversight is the ability to monitor and assess the performance of the regulated community—examining both discrete performance as well as historical trending over time. The single greatest challenge to PHMSA's ability to track performance, over time is the dynamic nature of the regulated community itself. Due to conversions of service, new construction, abandonments, or changes in operatorship that occur during divestitures, acquisitions, or contractual turnovers, operators' asset profiles often change year-to-year, rendering historical trending inaccurate. Currently, PHMSA does not receive any alerts, information, or notification of these types of changes and we lack any mechanism to track or capture these changes when they occur. As a result, PHMSA's ability to accurately portray and assess the performance of individual operators is severely compromised, with the situation deteriorating over time as operating and asset changes accumulate and compound.

Additionally, there is an increased burden to industry and to PHMSA in tracking and maintaining potentially numerous OPID's for the same company. Some companies accumulate a large number of OPID's, often inadvertently, as the company reports across a variety of lines of business (*e.g.,* operators may use separate OPID's for reporting their user fee mileage, safety-related conditions, NPMS submissions, incidents, and annual infrastructure and IM data.) The proposed National Registry of Pipeline and LNG Operators will facilitate the use of one OPID across a company's reporting requirements for a given set of pipeline segments or facilities thereby reducing the burden on both PHMSA and industry for tracking these multiple, duplicative OPIDs.

Comments

Many comments concerning the proposed OPID Registry addressed the proposal to require 60-days advance notice of certain events that can change the nature of the operator. INGAA, API, AOPL, and many operators commented that many of the events for which notification was proposed are business transactions that must remain confidential until they occur. Sometimes, this is dictated by requirements of the Securities and Exchange Commission or other agencies. Commenters also noted that even non-confidential changes may be delayed or modified before implementation, causing schedules to be delayed. INGAA and Piedmont suggested that annual reporting of changes should be sufficient and that per-event notification should not be required. They also suggested that PHMSA should obtain information currently reported to FERC, which duplicates some of the information proposed for the Registry. AGA, Atmos, and BG&E recommended deleting the proposed notification requirements because we had not articulated the need for the information. API and AOPL also asked that PHMSA explain the need for notifications. TPA suggested deleting certain notification elements. AGA, NiSource Distribution, and NWN noted that the information is already reported annually to NPMS or on other forms. SWGas sought an exemption for distribution pipeline operators from the notification requirements, contending that PHMSA has no authority to regulate the costs involved and that a relationship to safety is not obvious.

Commenters also expressed concern about the extent of information that would be required in notifications. Since the proposed notification form was not placed in the docket, AGA, Atmos, and BG&E claimed that they cannot estimate the burden notification would entail. API and AOPL suggested that PHMSA should identify the information to be included in notifications and provide an additional opportunity to comment. NiSource suggested that a form be developed for this purpose. SWGas and Paiute noted it was unclear how operators are to make required notifications. Atmos and TPA suggested that the proposed notification requirements should be delayed while PHMSA seeks additional comments.

Other comments in this area addressed concerns with specific elements of the proposed notification requirements:

- API and AOPL suggested that notification should be required for acquisition of a pipeline system rather than a pipeline facility because this is more consistent with the definitions in § 195.2.
- El Paso, SWGas, and Paiute suggested that additional guidance was needed concerning how to treat multi-year construction events for notification purposes. NiSource suggested that clarification was needed on how to address the costs for multi-year projects and further suggested that reporting for this criterion be moved to the annual report.
- AGA, API, AOPL, and numerous pipeline operators expressed concerns about the proposed notification requirement for rehabilitation, replacement, modification, upgrade, uprate, or update or construction of a new pipeline facility costing $5 million or more. They suggested deleting the dollar criterion completely, given that it is not indexed for inflation and would be likely to capture smaller projects in future years. They would rely solely on notification of construction of some threshold of miles of pipeline. El Paso and Spectra suggested increasing the threshold from $5 million to $10 million, noting that the cost of materials, contractors, and gas loss makes a $5 million project a relatively minor activity. National Grid would index the dollar amounts for inflation and limit their applicability to single projects vs. programs with multiple projects.
- Other commenters expressed concerns with the proposed notification requirement for rehabilitation, replacement, modification, upgrade, uprate, or update. API and AOPL would eliminate the proposed requirement noting that these changes are intended to improve safety, notification does not add to safety, and the results of these projects would appear in subsequent annual reports. Atmos suggested that the provision exclude changes that must be made in an emergency, since 60-day advance reporting would be impractical in such circumstances. Mid-American would delete this criterion completely, claiming it would delay emergency repairs. TransCanada suggested collecting this information via annual report after the events had occurred. NAPSR, on the other hand, supported reporting under this criterion, noting that the information is needed to address public concerns and inquiries.
- Some commenters questioned the mileage threshold for notification of pipeline construction projects. API, AOPL, Atmos, and TXOGA would increase the threshold from ten miles to 50 miles, noting that this is consistent with the proposed requirement for notifying of acquisition of an existing pipeline and that smaller construction projects would show up in annual reports. IUB suggested that the threshold be lowered to five miles because information about even small construction projects is necessary to plan safety inspections. Spectra supported 60-day prior notification for construction of more than ten miles of pipeline or a new LNG plant.
- INGAA pointed to a discrepancy between the preamble and the regulatory text on notification of changes in the entity responsible for major pipeline safety programs. INGAA suggested that notification should not be required. PST, on the other hand, suggested that the discrepancy was an omission from the regulatory language and that PHMSA add this notification criterion.
- Atmos and TPA suggested modifying the criterion for pipeline acquisition to refer to pipelines/facilities subject to Parts 192 and 193 rather than "regulated by PHMSA." They noted that the proposed language could lead to confusion for pipelines states regulate.
- IUB requested that the Registry capture contact information following acquisitions or mergers because this information has sometimes been difficult to determine. BG&E would limit notifications to maintaining current contact information. El Paso and Spectra suggested that a means to update contact information electronically would be less burdensome than current practice of requiring a letter to do so.
- API and AOPL suggested defining "operating entity" in the phrase "[a] change in the operating entity responsible for an existing pipeline, pipeline segment, or pipeline facility, or LNG facility."
- National Grid requested that PHMSA work with states toward single reporting per state per operator.

Another major area of comments was the perception that PHMSA was requiring operators to re-apply for their existing OPIDs. API and AOPL commented that operators should not have to re-enter information when re-applying, but rather record only changes in ownership. El Paso, OKIPA, and Piedmont objected to requiring operators to re-apply when PHMSA has not justified such a requirement. OKIPA commented further that operators should not be required to re-populate information based on a new OPID. Atmos and TPA commented that PHMSA should establish reasonable deadlines for operators to complete re-application and for PHMSA to establish a process to keep the information current. DOMAC suggested that it would be helpful to have more information on the content of information required when applying for an OPID.

Response

PHMSA acknowledges that many of the changes for which we proposed to be notified are business transactions that need to be kept confidential and for which advance notification is impractical. However, not all of the proposed notification criteria are in this category. New construction by an existing operator, including planned modifications, upgrades, rehabilitation and uprates, are not business transactions requiring such confidentiality. PHMSA has modified the proposed notification requirement to require notification of this type of activity 60 days in advance. We will require notification of business transactions that typically require confidentiality within 60 days after the event has occurred.

PHMSA requires advance knowledge of planned construction activities so that it can plan safety inspections and align appropriate inspection resources to conduct these inspections. For pipeline construction in particular, it is important to inspect construction activities while they are underway, given that the pipeline is often buried before being placed in service and it is not then practical to inspect the quality of construction. NAPSR's comments support this need, noting that states exercising safety jurisdiction also require advance notice for inspection planning.

PHMSA needs to know of changes in operator name, ownership, and responsibility for operations to adequately track ongoing safety performance, and to accurately portray safety performance over time, including the identification of emerging safety trends. Sale of an existing pipeline, or the complete acquisition or merger of a company may involve the wholesale adoption of standing operating and safety practices and programs. These programs may continue without change, or they may be integrated into the programs of a new owner. Additionally, sale of an existing pipeline may involve a complete replacement of staff. Personnel responsible for day-to-day operation of the pipeline often remain, becoming employees of the new owner. PHMSA must know when changes in responsibility occur, and the parties involved, to accurately evaluate and trend safety performance data through and following periods of change. Some information regarding ownership is currently reported via NPMS, but NPMS does not include all of the information PHMSA needs. Similarly, although there is duplication in some reporting elements with reports required by FERC, many pipeline and LNG facility operators are not subject to FERC reporting requirements making it impractical for PHMSA to rely on FERC information to serve its operational needs.

Whether ownership change is involved or not, sometimes there is a change in the primary responsibility for managing or administering one or more PHMSA-required safety programs. This situation arises when existing pipelines or LNG Facilities covered by a single OPID are part of a common PHMSA-required pipeline safety program or LNG safety program which also involves other assets covered by other OPIDs. (These common safety programs are sometimes referred to as "umbrella" safety programs.) For PHMSA to adequately evaluate these programs and accurately document compliance and safety performance over time, it must be clear, and PHMSA must have a current record of which OPIDs (and, by extension, which corresponding pipelines and/or facilities) are included under each PHMSA-required safety program, know when these OPIDs officially came under these programs, and, if and when these OPIDs are ever removed from these programs. Additionally, this type of notification serves to facilitate PHMSA's resource planning and preparations for the conduct of its inspections of these safety programs. These "common safety program" relationships involving multiple OPIDs entail a relatively small number of pipeline operators, something on the order of 10–15% of the total number of operators. And they also tend to be the larger operators with multi-state and multi-system operations which, in turn, represent approximately 70–80% of the total infrastructure mileage. As a result, PHMSA's ability to accurately track and monitor a large majority of the nation's most extensive pipeline infrastructure will be accomplished through this notification requirement affecting relatively few operators. And this capability to understand the make-up of these common safety programs over time and through operating and/or ownership changes is the cornerstone of a more data-driven PHMSA organization.

PHMSA and the states need to know of planned construction activities, mergers, acquisitions and other changes in safety responsibility for distribution pipelines as well as transmission pipelines. PHMSA is not proposing to regulate costs associated with distribution pipelines or any other type of pipeline, rather, PHMSA is using the costs of modifications that do not involve construction measurable in miles as a trigger for identifying projects PHMSA regulates and for which prior inspection planning is needed. PHMSA has thus not exempted distribution pipelines from the notification requirements.

Although the NPRM did not propose that operators must re-apply for OPIDs, PHMSA recognizes that the NPRM was not clear in this regard due to the number and nature of comments on this topic. PHMSA has modified this final rule to make it clear that operators to which OPIDs have been assigned prior to the effective date of the final rule must validate the information associated with those OPIDs, and not initiate an entire new application or reapplication process. This validation must occur within six months of the effective date of the final rule. Operators must access the information currently in PHMSA's records concerning their OPIDs (using an on-line, internet-based system) to make changes where appropriate, or to indicate that the information is correct. This will help PHMSA assure that the information in its National Registry of Pipeline and LNG Operators is a current and accurate baseline. The information that operators must validate must be consistent with the information required when applying for a new OPID. This information will be on the OPID Assignment Request form (referred to in the NPRM as the OPID Questionnaire).

PHMSA has made changes to some of the criteria for notification, but has not adopted all the changes commenters suggested:

• PHMSA does not agree with API and AOPL that notifications for acquisitions should refer to pipeline systems. Pipeline facility, as defined in both §§ 192.3 and 195.2, is a broader term that better represents the nature of changes in which PHMSA is interested.

• PHMSA does not agree that additional guidance is needed concerning multi-year projects. The NPRM would not have required annual notification but notification prior to initiation of a project meeting a reporting threshold (dollars or miles) regardless of how many years over which the project was to be accomplished. The final rule retains the structure of the proposal in this regard.

• PHMSA understands the concerns commenters expressed about using a dollar threshold to identify certain projects requiring notification, but sees no practical alternative. As described above, PHMSA (and states) require prior notification of projects for which in-progress safety inspection is appropriate. A mileage threshold could identify appropriate pipeline construction projects, but some significant construction projects do not involve miles of pipe (*e.g.,* construction of a new pump or compressor station). PHMSA has increased the dollar threshold from $5 million to $10 million and has limited its applicability to projects not involving line section pipe. PHMSA has not indexed this threshold for inflation but considers that the increase in size and limitation in scope obviates the concerns that smaller projects will be unnecessarily reported.

• PHMSA has also modified the reporting criterion for rehabilitation, replacement, modification, upgrade, uprate or other update to exclude changes that must be made on an emergency basis from the requirement for 60-day prior reporting. The final rule requires that operators notify PHMSA of emergency projects as soon as practicable.

• PHMSA has retained the 10-mile threshold for notification of projects involving construction of line section pipe. PHMSA recognizes that this is not consistent with the requirement to notify of acquisition of 50 miles of pipeline, but the needs addressed by each criterion are different. Acquisitions usually involve sizeable pipeline facilities; therefore, 50 miles is a reasonable criterion, and the information is needed to support accurate trending of safety data. PHMSA and states need information concerning pipeline construction to plan safety inspections, and a 10-mile construction project is large enough that safety inspections would be needed. PHMSA agrees with IUB that knowledge of even smaller construction projects (*e.g.,* IUB's suggested 5-mile criterion) would be useful in many cases, but considers 10 miles appropriate for this notification requirement.

• PHMSA has included a requirement to notify it of changes in the entity responsible for major pipeline safety programs. The failure to include this criterion in the proposed regulatory language was an oversight. As noted by PST, it was discussed in the NPRM preamble.

• PHMSA agrees with Atmos and TPA that reference to facilities regulated by PHMSA could cause confusion when facilities under state regulation are involved. PHMSA has modified the reference to facilities subject to Part 192, and has made a similar change to the Registry requirements for hazardous liquid pipelines in § 195.58.

• PHMSA understands the importance of updating company contact information and of reducing the burden for doing so. At the same time, PHMSA considers that a change in personnel, which could affect "contact information," is too fine a level of detail to require notification. Therefore, PHMSA has not adopted this requirement into the regulations. PHMSA will consider modifying the National Operator Registry to make it available for operators to report voluntarily changes in contact information.

• PHMSA has replaced the term "operating entity" so that the criterion in § 191.22 now refers to, "[a] A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility." This should alleviate any confusion introduced by the use of a new term.

• PHMSA will make available to state pipeline safety regulators information that it receives through the National Operator Registry. States, however, have their own information needs, requirements, and administrative procedures, and PHMSA cannot force states to use common reporting instruments.

PHMSA considers it reasonable that operators want to know the burden associated with obtaining an OPID and notification of changes. The NPRM referred to an OPID Questionnaire (now called the OPID Assignment Request form) which was not made available for public comment. PHMSA is adopting a form for submitting on-line notifications to the National Registry of Pipeline and LNG Operators. Therefore, PHMSA will publish a separate notice in the Federal Register providing the public an opportunity to comment on the proposed forms.

(6) Requiring Electronic Safety-Related Condition and Offshore Pipeline Condition Reports

49 CFR 191.25, 191.27, 195.56, 195.57 and 195.58

Proposal

In the NPRM, PHMSA proposed to require an operator of a natural gas or hazardous liquid pipeline, or of an LNG plant or LNG facility to use a new standardized form instead of the free-form Safety-Related Condition reporting now used. For offshore pipeline conditions, PHMSA requires an operator to report certain information within 60 days after completion of the inspection of all its underwater pipelines subject to §§ 192.612(a) or 195.413(a). PHMSA proposed also to obtain this information on a standardized form, filed electronically with PHMSA.

Comments

Many commenters objected to a change from the current requirement for when a safety-related condition must be reported. Operators must report safety-related conditions "within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition."[2] The proposed language in the NPRM revised this to read "* * * determines or discovers * * *" which commenters believed eliminated the current distinction between five days after determination and ten days after discovery of a condition.

SWGas and Paiute claimed that because safety-related conditions at LNG facilities are rare, a reporting form is not needed. These operators also asked that PHMSA describe how safety-related conditions relate to the categories of leak, failure, and incident a lack of common understanding affects the quality and consistency of reporting.

With respect to offshore pipeline condition reports, Spectra recommended not requiring reports for inspections that find no exposed pipe. INGAA joined with Spectra in suggesting PHMSA require a report 60 days after identifying exposed pipe that poses a hazard to navigation. El Paso and TransCanada similarly suggested treating these inspections like incidents or IM inspections for reporting purposes (reporting after an event or annually), as different criteria/timing for risk-based inspections makes comparing data difficult.

Response

After considering these comments and reevaluating our information needs, PHMSA has decided to withdraw the proposed safety-related condition report and associated changes to §§ 191.25 and 195.56 at this time. PHMSA will continue to evaluate its needs and may, again, propose changes to requirements for submitting safety-related condition reports and the information to be included in such reports. The proposed change to the timing for submission of safety-related condition reports was an error. PHMSA has withdrawn the proposed changes to these sections.

Safety-related conditions are not similar to leaks, failures, and incidents and do not fit into a hierarchy with these terms. Leaks, failures, and incidents are instances in which a problem has occurred. Safety-related conditions are conditions which make it more likely that a failure will occur, and, therefore, require additional attention from the operator and the safety regulator.

The comments concerning underwater pipeline condition reports highlighted an inconsistency in the current regulations that PHMSA had not considered adequately. The requirements in §§ 191.27 and 195.57 require reports 60 days after completion

[2] §§ 191.25 and 195.56.

of the inspection of all pipelines subject to §§ 192.612(a) and 195.413(a) respectively, but the referenced sections do not require an inspection of all pipelines at a specified period of time. Rather, inspections are required to be done on appropriate periodic intervals, which may vary for different pipelines for an individual operator. Therefore, there might be no time where inspection of "all" pipelines subject to the inspection requirements is completed, triggering the reporting requirements of §§ 191.27 and 195.57. Further, §§ 192.612(c) and 195.413(c) require prompt notification if an underwater pipeline is found to be exposed. PHMSA is withdrawing the changes proposed in the NPRM to §§ 191.27 and 195.57. PHMSA is also withdrawing the proposed forms related to these requirements. PHMSA will consider the appropriate manner in which to address this inconsistency and consider the comments received in this proceeding as part of any future rulemaking.

(7) Merging the Gas Transmission IM Semi-Annual Performance Measures Report with the Gas Transmission Operator Annual Reports

49 CFR 192.945 and 192.951

Proposal

In the NPRM, PHMSA proposed to merge the gas transmission IM Program semi-annual performance measure reports into an operator's annual report. We also proposed changes to the annual report.

The annual report has historically collected information on the number of leaks from each of seven causes. The IM performance requirements include the number of leaks, failures, and incidents from each of nine causes. This difference was the basis for GAO's recommendation in its report (GAO–06–946), "Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measure Should Be Improved" that PHMSA make changes to allow for optimal comparison of performance over time and make them more consistent with other pipeline safety measures. PHMSA modified the annual report to collect leak information for the same nine causes used in collecting the IM performance measure.

The gas transmission and gathering pipeline annual report is now filed by state (i.e., an operator whose pipeline traverses multiple states files one report for each such state). IM performance measures have been reported semi-annually by program, i.e., one report covering all pipelines within an IM program regardless of the state in which the pipelines are located. The NPRM noted that one consequence of integrating the IM performance measures into the annual report is that these measures would now be required to be reported by state.

Comments

AGA supported the changes to the annual report's cause categories and generally supported integrating the IM performance measure report with the annual report. AGA, joined by NWN, noted that this could cause some difficulties for operators with IM programs that cover multiple OPIDs, and who do not now separate IM results by individual OPID within the common program. These operators suggested a means of referring to data reported for the OPID under which a common IM program is managed rather than requiring reporting for each individual OPID within the program.

While AGA agreed that IM performance measures should be reported annually as part of the annual report, they disagreed that these measures should be reported by state. They claimed that industry does not now collect data on this basis and that the change will add significant burden with no appreciable effect on safety.

Geo Logic Environmental Services, LLC maintained that it would be overly burdensome to integrate IM performance measures with the annual report.

Response

Operators must report IM data by OPID. PHMSA recognizes that some operators manage common IM programs which include multiple OPIDs representing different system assets. IM activities, however, are conducted on individual pipeline segments (*e.g.,* in the case of assessments) or at individual locations along the pipeline (*e.g.,* in the case of repairs). Operators therefore have this data by OPID. Analyzing data by individual OPID provides a better opportunity to identify incipient problems. Operators with multiple OPIDs may have accumulated them by acquiring other pipeline systems, and problems may result from operation under the previous owner(s). Multiple OPIDs can also represent different pipeline systems of differing vintage and differing conditions. Prior treatment of pipelines by prior owners or problems associated with aging or certain types of vintage materials would be masked if IM information were reported at the common-program level. The annual report form requires reporting of IM data by individual OPID. At the same time, PHMSA needs to understand what OPIDs are included in common programs so that it can plan IM inspections appropriately and so that it can properly address any inspection findings which result. This information will now be collected and maintained as part of the National Registry of Pipeline and LNG Operators.

The issue of reporting IM information by state also affects proposed changes to hazardous liquid pipeline annual reports and is discussed below. The reporting burden is lessened, because reporting will be required annually vs. semi-annually. PHMSA has included this integration in this final rule.

(8) Modifying Hazardous Liquid Operator Telephonic Notification of Accidents Reporting Requirement

49 CFR 195.52

Proposal

In the NPRM, PHMSA proposed to require operators to have a procedure to calculate and provide a reasonable initial estimate of released product in telephonic reports to the NRC. PHMSA also proposed to require operators to provide additional telephonic reports to the NRC if significant new information becomes available during the emergency response phase of a reported event. This proposal was based in part on a recommendation from the NTSB that PHMSA modify 49 CFR 195.52 to require pipeline operators to have a procedure to calculate and provide a reasonable initial estimate of released product in the telephonic report to the NRC (NTSB Safety Recommendation P–07–07). NTSB also recommended that the hazardous liquid regulations require pipeline operators to provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response (NTSB Safety Recommendation P–07–08).

Comments

API, AOPL, TransCanada, and TPA noted that estimates made quickly for immediate reports are subject to error. These commenters requested that PHMSA include a provision holding an operator harmless for over-or-under estimates in its initial reports. API, AOPL and TXOPA recommended placing the requirement for a procedure to estimate release volumes in § 195.402, "Procedural manual for operations, maintenance, and emergencies" rather than in the reporting requirements of § 195.52.

TransCanada and TXOGA requested that PHMSA provide guidance on what would constitute a significant change in information necessitating a follow-up report to NRC. API, AOPL, OKIPA, and TXOPA suggested revising the regulatory text to limit the requirement for subsequent reports to situations in which an operator has a reasonable basis for significant revision of reported estimates. PST recommended requiring subsequent reports to be submitted "at the earliest practical moment" as is now required for initial reports.

API and AOPL commented that there is no mechanism to amend or rescind an NRC report and that one should be provided. TXOGA suggested that original and subsequent reports be retained by PHMSA for subsequent review and analysis.

Response

PHMSA recognizes that estimates of release made quickly for immediate reports are subject to error. Not all information can be known immediately with accuracy. Calculations must be based on assumptions, and those assumptions may not be correct. Still, information is needed quickly to estimate the scope of a problem and allow response by appropriate agencies/resources. This is why immediate reports to NRC are required. Operators are expected to make their best effort in making their initial estimates of release. Using a procedure to make those estimates should help improve their accuracy by allowing decisions concerning how estimates are to be calculated to be made through deliberative pre-planning rather than in haste after a major event. PHMSA has not modified this final rule to hold operators harmless for incorrect estimates, but would exercise appropriate discretion in any enforcement action that might result following an event reported to NRC in which a good faith effort was made.

Whether to place the requirement that operators have a procedure to estimate releases in §§ 195.402 or 195.52 is a matter of preference. PHMSA can see how some might consider that this requirement should be grouped with other requirements to have procedures. In the NPRM, PHMSA chose to incorporate this requirement into the provision requiring that reports be made to NRC, as recommended by NTSB. PHMSA has retained that choice in this final rule.

PHMSA does not agree that it is necessary to state in the regulation that an additional report is required for new information that provides a "reasonable basis" for modifying prior estimates. The proposed rule already limited the requirement for subsequent reports to instances in which "significant" new information becomes available. The proposal did not require a supplemental report for "any" new information. PHMSA considers that this qualifies the requirement sufficiently to allow operators to use judgment in deciding whether new information provides an appropriate basis for a supplemental report. PHMSA previously published guidance concerning changes that would be significant enough to justify a supplemental report to NRC. This guidance may be found in Advisory Bulletin ADB–02–04, published in the **Federal Register** on September 6, 2002 (67 FR 57060).

Immediate reports are made to NRC, not to PHMSA. PHMSA has no authority to change NRC processes, including establishing or changing any mechanism to amend or rescind a report or governing which data will be retained for subsequent analysis. Such changes are beyond the scope of this proceeding. PHMSA understands that NRC's current practice is not to remove reports from its database.

(9) Requiring Operators of Hazardous Liquid Pipelines to Report Pipeline Information by State on the Annual Report for Hazardous Liquid Pipelines

49 CFR 195.49

Proposal

In the NPRM, PHMSA proposed to require operators of hazardous liquid pipelines to submit certain infrastructure and IM data separately for each state a pipeline traverses.

Comments

API, AOPL, TXOPA, TPA, Spectra, and TransCanada objected to the proposal to collect information by state. TransCanada would allow collection of infrastructure data (*e.g.,* miles of pipeline) on this basis. These commenters noted that pipelines operate as systems and not by state; therefore, operators have no business reason to collect data on a by-state basis and do not currently do so. The commenters contended that given that the elements to be reported cross state lines, it would be unreasonably burdensome to require that the data be collected on a by-state basis. API and AOPL contended that contrary to the statement in the NPRM preamble which stated that the industry data team generally supported collection of data by state, is inaccurate. API and AOPL noted that in the 2004 rule that added the requirement for the annual report PHMSA acknowledged in its response to comments that mileage of hazardous liquid pipelines in each state is already available in the NPMS and that it was examining additional enhancements to NPMS that would allow collection of additional state-by-state information without imposing additional burden on operators. API and AOPL would limit collection of data by state to intrastate systems (for which an annual report would generally address only one state). API and AOPL claimed that the Regulatory Analysis supporting the NPRM was neither reasonable nor reliable because it did not consider the additional burden imposed by reporting information separately for each state.

OKIPA suggested that PHMSA obtain state based information from the states exercising jurisdiction. PST supported obtaining additional information on a by-state basis as this would increase PHMSA's ability to oversee state pipeline regulatory activities.

Response

This issue was discussed at some length during the Advisory Committee meeting discussed below. At that meeting, PHMSA agreed that it would be reasonable to roll up IM information nationally and to limit by-state reporting in the annual report for gas transmission and gathering pipelines and hazardous liquid pipelines, to infrastructure information. The Committees supported that approach. PHMSA has modified the proposed revision to the hazardous liquid pipeline annual report form along these lines and has revised this final rule to require reporting by state only for those parts of the form that indicate such reporting is required. PHMSA acknowledges that some information is available in NPMS by state, but all of the desired data is not. The NPRM discussed the difficulties involved in changing NPMS and PHMSA's uncertainty about each operator's ability to provide additional data via that system. PHMSA concludes that obtaining this information through NPMS is not practical at this time.

It is not practical to obtain state information from the states, as suggested by OKIPA. State reporting requirements vary. Additionally, states only exercise jurisdiction over intrastate pipeline systems. The only means to obtain consistent data for all pipelines is via a Federal requirement.

With respect to PST's suggestion that additional information by state would help PHMSA oversee state pipeline safety regulatory programs, PHMSA has the information it needs for this purpose. Some information will be reported by state via the annual report, as modified. PHMSA also obtains additional information directly from states that it uses in its oversight of state programs.

(10) Removing/Revising Obsolete Provisions

49 CFR 191.19, 191.27, 195.57 and 195.62

Proposal

In the NPRM, PHMSA proposed to remove or revise several provisions in light of the proposal to require electronic submission of all reports. These provisions were as follows:

• Remove § 191.19, which advises operators they may obtain, without charge, copies of paper report forms and reproduce the forms.

• Remove §§ 191.27(b) and 195.57(b), which require mailing hard copies of Offshore Pipeline Condition reports.

• Revise § 195.54 to remove the option to file an accident report by facsimile.

• Remove § 195.62, which requires operators to maintain an adequate supply of forms that are a facsimile of DOT accident report forms so that the operator may promptly report an accident.

The NPRM also indicated that hard copies of forms would continue to be available on PHMSA's Web site at *http://phmsa.dot.gov/pipeline*.

PHMSA received no specific comments on these removals/revisions and, therefore, we are adopting these removals/revisions as proposed.

(11) Updating OMB Control Numbers

49 CFR 191.21 and 195.63

Proposal

In the NPRM, PHMSA proposed to update several sections to add new OMB control numbers for the new forms (and information collection) proposed in the NPRM.

PHMSA received no public comments concerning these changes and have adopted them as proposed.

IV. Comments on Forms

In addition to comments concerning the proposed rule, PHMSA received comments on the related forms.

Comments on the Annual Report for Gas Transmission and Gathering Pipelines

Comments

INGAA, API, AOPL, and TPA commented that reporting mileage to three decimal places is more precise than is needed or justified. INGAA suggested miles be reported to the nearest tenth. The other commenters would report to the nearest mile.

Response

PHMSA agrees that reporting of mileage to three decimal places is unnecessary. At the same time, PHMSA notes that there are some pipelines less than one mile in length and for which it would be unclear whether zero or one should be reported if reporting were by mile. PHMSA has revised the form to allow reporting to one decimal place and has indicated that rounding to the nearest mile is allowed.

The annual report describes the status of a pipeline at the end of the reporting year and/or events that occurred during that year. Gathering lines that become regulated during a year should be reported as part of infrastructure on that year's annual report. Regulated events (*e.g.,* incidents) that occur during the year and following the date on which the lines become regulated should also be reported.

Part A—Operator Information

NAPSR would add CO2 to the list of commodities given that transport of CO2 as a gas is likely to become more prevalent with forthcoming carbon sequestration projects. SWGas and Paiute suggested defining "assets," as used in Part A.

INGAA and TPA recommended deleting the last boxes in question 8, "does this report represent a change from last year's final reported numbers for one or more of the following parts:" They contended that virtually all operators will experience one or more of these changes and that the rare case where none of the boxes would be checked does not warrant the inconvenience for others to respond. SWGas and Paiute requested clarifying the scope of changes that would trigger a response in question 8. NiSource commented that operators who experience no changes should not have to complete the remainder of the form. NiSource reads the form to indicate that operators with changes must complete only those sections for which changes affect the reported data while operators who do not experience any changes must complete the entire form. TPA noted that spaces are needed for operator Headquarters' state and zip code.

Response

PHMSA recognizes that carbon sequestration projects are likely to result in transport of carbon dioxide in gaseous form. At present, however, PHMSA does not have jurisdiction to regulate transportation of carbon dioxide as a gas. Legislative change would be required to establish jurisdiction; therefore, PHMSA cannot accept NAPSR's suggestion to add CO_2 as a gas to the list of commodities transported.

PHMSA accepts that the term "assets," could be confusing and has replaced this term with "pipelines" and "pipeline facilities," both of which are defined in the regulations.

PHMSA has revised Question 5 and the instructions to resolve confusion concerning how to report IM data. IM data is to be reported by individual OPID and not as part of a common program under one OPID, as discussed above. The revised question simply asks whether the pipelines and pipeline facilities under the OPID being reported are under an IM program. If not, the form indicates which parts (*i.e.,* those collecting IM-related data) the operator need not complete.

PHMSA has revised question 8 in response to the comments on this portion of the form and to comments made about a similar question on the hazardous liquid pipeline annual report form. PHMSA has combined the blocks operators would use to report changes due to mergers and acquisitions, as suggested by API and AOPL, for the hazardous liquid form because these two terms can be confused and there is no reason to report the events separately. PHMSA has also revised question 8 to indicate that operators who have experienced no changes need not complete many sections of the form for which data would be identical to that reported in the prior year. (Note that this is not applicable to reporting for calendar year 2010 given that the data on this form will be reported for the first time during that year). PHMSA concludes this will reduce the reporting burden for operators who do not experience changes to their pipeline systems. Operators who experience changes due to any of the reasons listed in question 8 must complete the entire form.

PHMSA notes the confusion regarding the intent of question 8. In particular, INGAA and TPA claimed the question was unnecessary because virtually all operators would experience one of the listed changes during any given year. PHMSA advises that simply experiencing such a change does not lead to a "yes" answer to this question. Instead, "yes" indicates that the numbers reported on the prior year's form have changed as a result of one of the listed events. PHMSA intends to use the responses to this question to understand why data that was reported changed for a given operator from year-to-year and to help prioritize its inspection activities. In addition, eliminating the need for operators who have not experienced changes that affect data reported previously to report the same data again will improve data quality by avoiding collection of inaccurate data due to data entry errors. For example, operators who experience a modification to their pipeline (one of the listed changes) but for whom that modification results in no change to the numbers reported on the prior year's annual report would answer "no" to question 8 and would not be required to complete the bulk of the form (except for 2010). PHMSA has made editorial changes to the form to emphasize this.

PHMSA has made a number of other editorial corrections to the form, including adding space for operator headquarters' state and zip code.

Part B—Transmission Pipeline HCA (High Consequence Area) Miles

INGAA suggested deleting the number of offshore miles because there are not enough miles of offshore transmission pipeline to make the data pertinent.

Response

PHMSA will require reporting of offshore HCA miles. Although there may be few such miles, they do exist (*e.g.,* an offshore platform that includes a transmission line and is occupied by 20 or more persons). Operators who have no offshore HCAs, which PHMSA recognizes will be most operators, may enter zero in this field.

Part C—Volume Transported in Transmission Pipelines Only in Million Standard Cubic Feet (mmscf)-Miles Per Year

AGA contended that it would be unreasonably burdensome to report volume transported. INGAA and Spectra maintained that because transported gas does not necessarily traverse an entire pipeline reporting volume-miles is impractical and PHMSA should use data already collected by FERC. Atmos, TPA, SWGas, and Paiute commented that this information does not appear relevant to pipeline safety and would be difficult to collect, particularly for bi-directional pipelines. GPTC and Nicor commented that this element is impractical for distribution pipeline systems in which only a small portion of pipeline is defined as transmission due to operating pressure. They noted that it is impractical to determine how much gas flowed through these limited portions of a pipeline system and questioned the safety need for the information. NiSource and NWN also claimed that it is unclear why PHMSA needs this information and that it may be proprietary or is already available from FERC. TPA suggested that, if we retain this section, we specify the reporting basis (*e.g.,* standard temperature and pressure) because some states (*e.g.,* Texas) require reporting of volumes under other pressure bases.

Response

PHMSA recognizes that it is difficult to determine the amount of gas transported, in mmscf-miles, for pipelines with multiple locations at which gas can be collected and delivered. At the same time, an indication of the total volume of gas transported will be useful data for PHMSA's analysis of pipeline safety performance. Such information can, for example, be used to normalize analyses of different events. PHMSA has revised this part to require reporting of the total volume of gas transported under the reporting OPID during the reporting year for operators who do not operate their transmission lines as part of a distribution pipeline system. PHMSA recognizes that this will not accurately represent the volume carried in only portions of interstate gas transmission systems, but PHMSA believes this strikes an appropriate balance between the burden to calculate mmscf-miles and the need for an overall measure of relative activity of different OPID transmission volumes. PHMSA will use this information with care.

PHMSA also recognizes that it would be particularly difficult for operators of distribution pipeline systems in which only a portion of the pipeline is classified as transmission to estimate the volume of gas carried by their transmission pipelines. PHMSA has revised this part to eliminate the need to report volume transported for operators who operate transmission pipelines as part of a distribution pipeline system. Volume information for these pipelines will be collected on the distribution pipeline system annual report, which PHMSA is currently revising.

PHMSA notes that the proposed instructions for this part included a definition of mmscf as million standard cubic feet and noted that standard conditions are "normally set at 60F and 14.7 psia." PHMSA has deleted the word "normally" to make clearer that these are the conditions at which volume is to be reported. PHMSA has also revised the proposed instruction to reflect a pressure of 14.73 psia to be consistent with how FERC describes standard conditions.

Part F—Integrity Inspections Conducted and Actions Taken Based on Inspection

INGAA commented that PHMSA should make clear that only testing conducted as a result of IM requirements should be reported.

AGA contended that PHMSA has not justified collecting more detailed IM performance data. SWGas and Paiute claimed that PHMSA does not need additional data to judge the adequacy of IM. National Grid does not support reporting information beyond the number of immediate and scheduled repairs in HCAs, because additional data would cause confusion due to overlapping inspection techniques.

Atmos and TPA commented that reporting the number of assessments by tool type would overstate the mileage assessed compared with other assessment types given that operators typically run multiple tools over the same mileage as part of a complete assessment. AGA and NWN claimed that collecting repair data by assessment technique would be burdensome with no apparent safety benefit, and that information concerning assessments conducted by method has no apparent safety value. INGAA, GPTC, and NiSource recommended deleting questions concerning inspections by tool type, contending that separate collection is misleading, will lead to incorrect mileage totals, and is of marginal value. INGAA also would limit miles inspected and actions taken for hydrotests to HCA miles because that is the only area with consistent repair criteria.

Atmos and TPA also maintained that reporting the number of conditions identified for repair by various assessment techniques, particularly outside HCAs, will provide no useful information given that there are no common criteria for when repairs are required. AGA argued that repairs outside of HCA should not be reported because this data serves no safety benefit and PHMSA has not justified collecting this data. GPTC, NiSource, Nicor, NWN, Piedmont, and INGAA also supported this position.

AGA and NWN maintained it would be more useful to collect data on anomalies identified by assessment cycle (*e.g.,* baseline, first re-assessment) rather than by tool.

National Grid noted that because "one year" and "scheduled" conditions are the same under § 192.933, both terms should not be used. GPTC and Nicor would clarify that the number of anomalies within HCAs (section 2c) should be the number repaired. AGA, GPTC, NWN, SWGas, Paiute, NiSource, and Nicor suggested that consistent and more-detailed definitions are needed for the terms leak, failure, incident, and rupture if consistent reporting is to be achieved. They further suggested PHMSA consider whether events of this type are to be reported based only on IM assessments or from all means by which they are identified. BG&E suggested that PHMSA conform terms to their use elsewhere and specifically use the terms "immediate," "scheduled," and "monitored," as used in Subpart O of Part 192, to refer to anomalies of concern under IM requirements.

Sempra Energy Utilities (Sempra) recommended modifying this part to allow an operator to reference another OPID for IM data. This would accommodate situations in which IM activities are managed under a common program for multiple OPIDs. NWN also noted that IM programs are often run in common for multiple OPIDs making it difficult to break out the data for individual OPIDs.

GPTC noted that question 5b refers to in-line inspection (ILI) even though the subject of question 5 is non-ILI techniques. NiSource would delete Part F5, since it duplicates information collected elsewhere on the form.

Response

PHMSA does not understand completely why INGAA believes that only testing conducted as a result of IM requirements should be included. If, as INGAA suggested "overtesting" (*i.e.,* testing of non-HCA miles assessed as part of an IM inspection) were included, what would be excluded for these segments? While the regulations establish maximum reassessment intervals, they also require that operators base their reassessment intervals on the identified threats, data from the last assessment and data integration (§ 192.939). Assessments that are conducted at shorter intervals than the maximums specified in the regulations provide additional data that must be considered in data integration and thus come under the provisions of IM regulations (see the response to FAQ–70 on the gas integrity IM Web site, *http://primis.phmsa.dot.gov/gasimp,* for additional discussion). Therefore, all testing on pipelines with HCAs must be reported.

Assessments that are conducted on pipelines that do not contain any HCAs are a different matter. Such pipelines are not covered by the IM provisions of the regulations. Operators are not required to report data for portions of these pipelines that they may assess for other reasons. PHMSA will consider future regulatory changes to establish requirements for reporting assessments and repair actions on pipeline segments that do not include HCAs.

Although PHMSA recognizes that there are no criteria in the regulations for when anomalies outside of HCAs must be repaired, PHMSA is aware that operators repair many anomalies outside of HCAs. PHMSA considers it important to understand when such repairs are being made and any trends (*e.g.,* are the number of repairs increasing over time). PHMSA recognizes that operators use different criteria for these repairs and that the data must therefore be used with care. This does not mean, however, that the data is not meaningful. Any data that is indicative of the condition of U.S. pipelines has value in PHMSA's analyses and decision making. PHMSA disagrees with INGAA's suggestion that repairs performed as a result of hydrotests should only be reported when they occur within HCA miles. Hydrotests identify defects, by causing leakage or a rupture, which must be repaired and, therefore, provide the most consistent "criteria" for repair of defects outside HCAs of any assessment method.

Similarly, collecting data by tool type and other assessment methods will be useful in informing PHMSA decision making and in improving PHMSA's understanding of the relative effectiveness and extent of use of various assessment methods. PHMSA recognizes that adding the miles assessed by different assessment methods provides a result that appears to overstate the number of pipeline miles actually assessed. Adding miles does, however, provide a better indicator of the number of miles by assessment method. Again, PHMSA recognizes that the totals need to be used with caution. Still, it will be appropriate to use them for some purposes, while miles inspected using individual tools (also collected in this part) or total HCA miles (collected in Part B) will be more appropriate for other uses.

PHMSA agrees that it could be more useful to collect data on the number of repairs in each assessment cycle. The effectiveness of IM regulations would be demonstrated by a reduced number in subsequent reassessments. PHMSA considers, however, that it would be more difficult to collect and use this data. New HCAs on pipelines previously assessed make it unclear how to differentiate between baseline and reassessment, for example. Given that operators now collect data per integrity assessment method trends in this data over time will better reflect the relative effectiveness of IM.

PHMSA has been careful to use terms with meanings commonly understood within the pipeline industry. The terms "leak," "failure," and "incident" are defined in the instructions consistent with ASME/ANSI B31.8S and with current regulations. PHMSA recognizes that these terms are used in other situations and will try to ensure consistent use on other forms. Use of the term "scheduled" to identify some IM anomalies is also consistent with the regulations and is not redundant with "one-year conditions." Section 192.933(c) requires that operators schedule some anomalies for remediation consistent with the scheduling provisions of ASME/ANSI B31.8S, while § 192.933(d)(2) identifies some specific anomalies as "one-year conditions." PHMSA has revised the section references on the form (which both previously referred only to § 192.933) to make this distinction more clear.

PHMSA acknowledges that question 5 in Part F inaccurately referred to ILI inspections. This question is intended to address assessments by other techniques. PHMSA has corrected this error, which eliminates the duplication NiSource noted.

We addressed above in the section on "Creating a National Registry of Pipeline and LNG Operators" comments about reporting IM data by individual OPID vs. under a common program.

Part G—Miles of HCA Baseline Assessments Completed

INGAA suggested that this section be broken into separate sub-sections for each reassessment. Atmos and TPA reported that they did not see how reporting assessments by vintage was useful. Spectra noted that HCA miles complicate the treatment of vintage given that an assessment by ILI often inspects more than just HCA mileage. A new HCA within a piggable segment, for example, may undergo a baseline assessment at the same time that other HCAs within the segment are being reassessed.

Response

At this time, PHMSA agrees that collecting data on assessment vintage (*i.e.,* first, second, etc.) is not necessary. PHMSA may revisit the need for this information as part of future activities. PHMSA has revised this part to collect data on the number of baseline miles completed and the number of reassessment miles (regardless of vintage). PHMSA expects that there will be a reduction in the number of anomalies identified in reassessments vs. initial baseline assessments, and needs this data to validate that expectation.

Part H—Miles of Pipe by Nominal Pipe Size

INGAA noted that the proposed form does not allow reporting of odd pipe sizes. The form provides for reporting of even pipe sizes specified in modern standards, but INGAA noted that intermediate sizes may exist in older systems, particularly for grandfathered pipe. INGAA also noted that the largest pipe size included in the form is 36-inch diameter and pointed out that larger pipe is being used/planned for some gas transmission pipelines.

Response

PHMSA acknowledges that odd pipe sizes may exist in some pipeline systems, including small diameter pipe (*e.g.,* 5-inch diameter) and pipe installed in older pipeline systems before pipe sizing was standardized. PHMSA has modified the form and instructions to accommodate reporting of odd pipe sizes and to include sizes larger than 36-inch diameter.

Part J—Miles of Transmission Pipe by Specified Minimum Yield Strength

AGA, NWN, SWGas, and Paiute commented that reporting pipeline mileage by specified minimum yield strength (SMYS) would be unduly burdensome because records are incomplete, grandfathered pipe may not fit into standard categories, and information technology (IT) changes would be needed to track mileage by SMYS. These commenters see no safety benefit in doing so. Atmos and TPA would also delete this section although they recognized there could be some benefit in reporting for pipelines operating under special permits or at 80% SMYS where special regulatory attention may be needed. They suggested that targeted reporting for these pipelines should be established rather than imposing an unjustified burden on all pipeline operators. TPA claimed that some operators of gathering pipelines treat all of their lines as Type A rather than determining the percentage of SMYS at which they operate and that it would be unreasonable to require operators to make this determination solely for this reporting.

NiSource noted that no allowance is made for pipelines operating at an unknown percentage of SMYS even though the regulations allow operations without this determination. For example, § 192.739 provides for determining a pressure limit for pipeline operating at an unknown percentage of SMYS. NiSource also noted that plastic and iron pipe are excluded, even though some transmission pipe is constructed of these materials. NiSource also claimed that the information collected via Part J largely duplicates information from Part K, miles of pipe by class location.

INGAA suggested that we eliminate blacked-out cells (implying that no pipeline should exist in that category) and noted that there is no offshore transmission pipeline that exceeds 72 percent SMYS.

Response

PHMSA considers this data to be important. The thresholds dividing the various categories in the table reflect regulatory requirements (*e.g.,* change in design factors) and PHMSA needs to have an understanding of the inventory of pipe to which these requirements apply. PHMSA notes that INGAA, which represents transmission pipeline operators who would tend to have pipeline across the range of allowable percentages of SMYS, did not object to reporting this data. Rather, AGA and some of its member companies expressed concerns. These companies generally operate distribution pipeline systems. While many of their systems include some transmission pipeline, the amount is relatively less and most tend to operate in the lower percentage SMYS categories. Thus, the burden for completing this section will be less for these companies.

While the regulations establish design thresholds consistent with those in this part, existing pipelines do not always fit into these neat categories. Pipe that was installed prior to the time pipeline safety regulations were initially established (i.e., pre-1970) may operate at maximum allowable operating pressures (MAOP) based on historical operation prior to that date (so-called "grandfathered pipe") and this pressure is in some cases in excess of 72 percent SMYS. Some pipe operates under special permits that allow different MAOP. Some pipe operates at MAOP greater than originally designed due to changes in class location and the allowance for pressure increase that is inherent in § 192.611. PHMSA is not persuaded by arguments that it is too hard for pipeline operators to acquire this data. Pipeline operators should acquire this data wherever possible because of its importance. Pipe operating at a higher percentage of SMYS has less safety margin. It is important that operators know where this pipe is and take this factor into account in the risk analyses required by IM regulations.

For these reasons, PHMSA has retained this part. PHMSA has made changes in response to the other comments concerning this part. PHMSA has eliminated blacked out cells. As discussed above, grandfathering, special permits, and other circumstances could result in pipe operating at various combinations of MAOP and class location and PHMSA agrees it is more appropriate to allow for data collection in all categories. Operators with no pipe in individual categories will simply enter zero. The revised form allows for pipe that operates at an unknown percentage of SMYS and for pipelines other than steel. PHMSA has also deleted the row corresponding to offshore transmission pipeline with MAOP greater than 72 percent SMYS.

The information collected in this part does not duplicate that in Part K. PHMSA agrees that the information in the two parts is related. Important information will be obtained through analyses that compare the information obtained in each of these parts. This will help PHMSA understand, for example, the amount of pipe that operates at MAOP higher than initial design due to the automatic-increase provisions in § 192.611. It is necessary to collect the data in both parts to allow this kind of correlation to be made.

Part J applies to transmission pipeline. Operators of gathering lines need not complete Part J.

Part K—Miles of Pipe by Class Location

SWGas and Paiute commented that this section appears to replicate Part B insofar as it relates to miles in HCA. They claimed it could be confusing to report miles that are not in an HCA but which must be inspected anyway under the IM program.

SWGas recommended that we exempt distribution pipeline operators that also report on transmission pipeline they operate. Many distribution operators treat all of their pipeline as Class 3 or 4 and do not perform analyses to determine accurately the class location of their transmission pipeline. SWGas opposed requiring such analyses solely to meet this reporting requirement.

Response

PHMSA agrees that reporting HCA miles in the IM program in this part duplicates Part B and has eliminated this section of Part K.

This part does not require that operators perform Class location studies if they do not do so for other purposes. Operators of distribution pipeline that treat all of their pipeline as Class 3 or 4 should report the mileage that they consider to be in each Class.

Part L1—Leaks Eliminated/Repaired During Year and Failures/Incidents in HCA

Atmos, NWN, and TPA requested clarification as to whether leaks repaired in IM assessments and reported in Part F are also to be reported in this part.

Nicor and NWN suggested reorganizing the columns for failure, leak, and incident data in order of severity to provide clarity and help assure consistent reporting. AGA noted that the failure category was omitted for gathering pipelines.

NAPSR suggested adding a column for unregulated gathering lines, as they consider that data should be collected for all gathering lines.

Response

Operators are to report all leaks both in HCAs and outside HCAs. Failures and incidents are to be reported for HCAs. This is an existing performance measure required by § 192.945 (through reference to ASME/ANSI B31.8S) that has been reported on semi-annual performance measure reports.

PHMSA agrees that reordering the columns in order of relative severity could improve clarity and has made that change.

While PHMSA agrees with NAPSR that it would be beneficial to have data for unregulated gathering lines, such lines are by definition unregulated. PHMSA cannot impose a reporting requirement on these pipelines without a regulatory change. Such changes are beyond the scope of this rulemaking.

Part N—Certifying Signature

Atmos and TPA suggested that a separate signature block be used to certify IM information because the proposed form implies certification of the entire form, which is not required. INGAA noted that the references to the parts of the form containing IM information, and for which certification is required, were incorrect.

Response

PHMSA has revised the form to make it clearer that executive certification applies only to IM information. PHMSA will also clarify this in the on-line electronic reporting system.

Instructions

Atmos and TPA commented that the instructions need to reflect electronic reporting and address the requirements for seeking alternate reporting methods.

TPA suggested that the instructions define interstate pipelines as those to subject to FERC jurisdiction "under the Natural Gas Act" rather than simply "subject to FERC jurisdiction," noting that some intrastate pipelines are subject to limited FERC jurisdiction.

NAPSR suggested defining synthetic gas. NAPSR also suggested clarifying the instructions on counting repaired leaks. For example, if a section of pipe with leaks is replaced, does PHMSA consider that one repair or must the number of leaks within the section be reported?

SWGas and Paiute contended that the definition of operator in the instructions is inconsistent with the definition in the regulations in that it introduces the term "substantial control."

INGAA suggested that the instructions for Part F, Question 4 should refer to "meeting repair criteria" rather than "exceeding." INGAA also suggested that the instructions for Part G should mirror those for Part F.

SWGas and Paiute suggested that the instructions for Part J clarify reporting for pipe that is classified as transmission under the functional aspects of the regulatory definition even though it operates at less than 20% SMYS.

Response

PHMSA has revised the instructions to address requirements for applying for alternate methods (*i.e.,* non-electronic) of data submission and to use the statutory definition of interstate pipeline from 49 USC 60101. PHMSA has included a definition of synthetic gas that is consistent with the definition in the instructions for the new incident report form. PHMSA has also reviewed and revised all definitions to be consistent with regulations.

Counting leaks has always been problematic. As NAPSR pointed out, when a section of pipe is replaced due to leakage, an operator could count the repair as one repair or as the number of leaks in the replaced section. When replaced pipe is retired in place, it may not be possible to count the number of leaks. Operators have previously been required to report the number of leaks repaired as part of their annual reports. Operators should report the number of leaks repaired based on the best data they have available. For sections replaced, but retired in place, operators should consider leak survey information to determine, to the extent practical, the number of leaks in the replaced section.

PHMSA has made editorial changes concerning repair of anomalies "meeting" repair criteria. INGAA's suggestion that the instructions for Part G mirror those for Part F was predicated on its recommended expansion of Part G so that the parts would be similar in content. As discussed above, this change is not necessary because we have simplified Part G to reflect only baseline and reassessment miles, regardless of vintage.

PHMSA does not understand the basis for confusion over whether Part J should apply to transmission pipelines operating at less than 20 percent SMYS. The proposed part explicitly included a section in the form for pipeline operating at less than or equal to 20 percent SMYS. Nevertheless, PHMSA has clarified in the instructions that Part J applies to all transmission pipeline.

Comments on the Annual Report for Hazardous Liquid Pipelines

General Comments

API and AOPL commented that mileage should be reported to the nearest mile rather than to three decimal places citing a lack of need or justification for the proposed level of precision. API and AOPL also commented that reporting by state should be limited to infrastructure data (*e.g.,* miles by state) and that by-state reporting of IM data should be required for intrastate pipelines only because interstate hazardous liquid pipelines are operated as systems and operators do not keep or track data by state. They noted that reporting all data by state would be a significant increase in burden with no corresponding increase in safety.

Response

PHMSA agrees that reporting of mileage to three decimal places is unnecessary yet notes that for those pipelines less than one mile in length it would be unclear whether zero or one should be reported, if reporting were by mile. PHMSA has revised the form to allow reporting to one decimal place and has indicated that rounding to the nearest mile is allowed.

PHMSA also agrees that reporting all IM data by state is unnecessary. PHMSA has revised the form and instructions to require that IM data be reported once for all interstate pipelines under an OPID. We will continue to require data for intrastate pipelines to be reported by state.

Part A—Operator Information

API and AOPL submitted a number of comments on this part. They recommended that PHMSA—

- Make explicit the implication in the first box of question 5 that lines that cannot affect an HCA need not be in an IM program.
- Clarify question 5 regarding how information for companies under a common IM program is to be collected. Specifically, they contended that

operators of pipelines that are under a common program should not be required to be report data that will be reported for the OPID under which the common program is managed.

• Delete question 7, which asks operators to list the states in which their inter- and intrastate pipelines are located, since this duplicates information collected elsewhere on the form.

• Combine the first two sub-blocks of Question 8, Part 3 because mergers and acquisitions can be confused.

• Revise question 4 to add space for state and zip code.

Response

PHMSA has revised Question 5 but has not accepted all of the suggestions. While in most cases pipelines that cannot affect an HCA are not in an IM program, that is not universally true. Some pipelines that cannot affect HCAs are covered by an IM program as a result of special requirements imposed by compliance orders or as conditions of a special permit, for example. PHMSA expects IM data for these pipelines to be reported as part of the annual report. IM data is to be reported by individual OPID and not as part of a common program, as discussed above. PHMSA has revised question 5 and the instructions to make this clear. The revised question simply asks whether the pipelines and pipeline facilities under the OPID being reported are under an IM program. If not, the form indicates which parts (*i.e.,* those collecting IM-related data), need not be completed.

PHMSA has revised question 6. Although we received no comments on this question, review of the form to address other comments revealed that PHMSA had omitted biofuels/ethanol as a commodity type. On August 10, 2007, PHMSA published in the **Federal Register** (72 FR 45002) a determination that transport of unblended biofuels by pipeline is under its jurisdiction and has previously revised the accident report form (PHMSA F 7000–1) to include this commodity type. Operators would select this commodity type in question 6 for pipelines that predominantly carry unblended biofuels. Transportation of biofuels blended with refined petroleum products would be reported as Petroleum Products/Refined Products. PHMSA is aware of only a limited number of miles of U.S. pipelines in Florida and Texas that currently transport unblended biofuels, but notes that some operators have expressed an interest in constructing such pipelines.

PHMSA has retained question 7. There is little burden associated with answering these questions given that operators are aware of the states in which their pipelines are located. Answering this question in Part A helps position the operator to complete the remainder of the form. The answer also provides an opportunity for PHMSA to cross-check that necessary data is, indeed, reported for all appropriate states as part of its ongoing efforts to assure data quality.

PHMSA has revised question 8 in response to the API and AOPL comment and to comments made with regard to a similar question on the gas transmission and gathering pipeline annual report form. PHMSA has combined the blocks operators would use to report changes due to mergers and acquisitions because these two terms can be confused and there is no reason to report the events separately. PHMSA has also revised question 8 to indicate that operators who have experienced no changes need not complete many sections of the form for which data would be identical to that reported in the prior year. (Note that this is not applicable to reporting on this form for calendar year 2010 because the data will be reported for the first time during that year). This will reduce the reporting burden for operators who do not experience changes to their pipeline systems. Operators who experience changes due to any of the reasons listed in question 8 must complete the entire form.

There has been some confusion regarding the intent of question 8. In particular, comments submitted with respect to the gas transmission and gathering pipeline annual report form suggested that the question was unnecessary because virtually all operators would experience one of the listed changes during any given year. In response, PHMSA notes that simply experiencing such a change does not lead to a "yes" answer to this question. Instead, "yes" indicates that the numbers reported on the prior year's form have changed as a result of one of the listed events. PHMSA intends to use the responses to this question to understand why reported data changes for a given operator from year-to-year and to help prioritize its inspection activities. In addition, by eliminating the requirement for operators who have not experienced changes that affect data reported previously to report the same data again will improve data quality by avoiding collection of inaccurate data due to data entry errors. For example, operators who experience a modification to their pipeline (one of the listed changes) but for whom that modification results in no change to the numbers reported on the prior year's annual report would answer "no" to question 8 and would not have to complete the bulk of the form (except for the reporting of calendar year 2010 data). PHMSA has made editorial changes to the form to emphasize this.

PHMSA has also changed the form to allow state and zip code information to be entered for the operator headquarters' address.

Part C—Volume Transported in Barrel-Miles

API and AOPL recommended allowing reporting for more than one commodity, adding columns for crude oil, refined products, HVL, and CO_2. They maintained that these changes would return to the intent of the current form.

Response

PHMSA had revised this part of the form to reflect the requirement that operators must file separate annual reports for each pipeline carrying a different commodity type. PHMSA recognizes that the operator files only one annual report for each pipeline system based on the commodity predominantly carried. PHMSA has restored the option to report volume for all commodities, as suggested by API and AOPL, thus eliminating the possibility of double reporting mileage of batched systems.

Part D—Miles of Pipe by Corrosion Protection and

Part H—Miles of Pipe by Nominal Pipe Size

API and AOPL suggested that we revise the titles of these parts to explicitly apply to steel pipe.

Response

Corrosion prevention, the subject of Part D, only applies to steel pipe and PHMSA has revised the title of this part accordingly. Part H applies to all pipe. PHMSA recognizes that most pipe in hazardous liquid pipeline systems is steel, nevertheless, there is some non-steel pipe in some systems. PHMSA has not revised the title of Part H and expects operators to report this data for all pipe materials.

Part F—Integrity Inspections Conducted and Actions Taken Based on Inspection

API and AOPL suggested a number of changes for this part:

• Refer to "could affect an HCA" vs. "HCA affecting." The former is defined in the regulations while the latter is not.

- Refer to "anomalies repaired" vs. "conditions repaired" for consistency with the Plastic Pipe Data Committee reporting. They would have the instructions refer to API RP 1163 for a definition of "anomaly."
- Clarify that repairs are to be reported for the year in which the repair is made rather than the year in which an assessment was conducted.
- Add actions (*e.g.,* repairs) for ruptures that occur during pressure tests.
- Add an option to question 1 for a combination ILI tool, since use of combination tools is becoming more prevalent.
- Clarify that the state identifier is required only for intrastate pipelines.

Response

PHMSA agrees it is better to use terms defined in the regulations, and has revised the form to use "could affect an HCA" rather than "HCA affecting."

The regulations refer to repairs that must be made following IM assessments as "conditions" (*i.e.,* immediate repair conditions, 60-day conditions, 180-day conditions). PHMSA has retained use of this term for those elements of questions in Part F that refer to repairs made that are required by the rule. PHMSA has revised the form to use the term "anomaly" for those elements that refer to repairs made as a result of an operator's criteria, which may be different than those in the rule. PHMSA has not adopted the suggestion to refer to API RP 1163 for the definition of anomaly. API RP 1163 is not currently incorporated by reference into the Code of Federal Regulations. Further, PHMSA considers it more important to understand anomalies that operators determine require repair. Operators may use the definition in API RP 1163 or they may use a different definition. Data concerning the number of repairs made as a result of operator-defined repair criteria should be reported in terms of the number of repairs actually made, regardless of a formal definition of the term "anomaly."

PHMSA has clarified that data to be reported for pressure test ruptures should reflect the number of repairs made. PHMSA has also revised the header for Part F to clarify that the state identifier is only applicable to intrastate pipeline systems.

PHMSA has not modified the list of tool types to include a combination tool. PHMSA recognizes that combination tools are becoming more common. When using such a tool, an operator is inspecting its pipeline using each of the tools included in the combination, and the number of miles inspected should be reported for each of those tool types. Reporting the data once for a "combination" tool would confuse the data concerning the prevalence of different ILI inspection methods.

Part G—Miles of Baseline Assessments and Reassessments Completed (HCA-Affecting Segment Miles Only)

API and AOPL would delete this part because the baseline period is over for all pipelines and collecting assessments by vintage would add confusion while adding no useful information. They further commented that PHMSA should clarify that the state identifier is only required for intrastate pipelines, if PHMSA retains this part.

Response

PHMSA has not deleted this part. Contrary to API's and AOPL's assertion, the baseline period is not over for all pipelines. The baseline period is still running for rural low-stress pipelines recently made subject to Part 195, for example. New baseline assessments can also be expected as a result of new HCAs and new pipelines. PHMSA has revised this part to require data for baseline assessments and reassessments and has eliminated the need to report mileage by the vintage of reassessment (*e.g.,* first, second). PHMSA agrees that this could be confusing, particularly when new HCAs develop near pipelines already assessed. PHMSA expects that data will show a significant drop in the number of conditions requiring repair as a result of reassessments compared to baseline assessments but does not expect the same trend between reassessments.

PHMSA has clarified that the state identifier is only required for intrastate pipeline systems.

Part J—Miles of Pipe by Specified Minimum Yield Strength

API and AOPL would limit this part to a report of pipe above or below 20% SMYS because the additional categories are of limited use.

Response

PHMSA has retained the proposed breakdown for this part. There are few categories in addition to the two suggested by API–AOPL (*i.e.,* above and below 20 percent SMYS). The limited additional data required addresses non-steel pipe. Pipeline operators should acquire this data wherever possible. This data is important to pipeline operators so that they know where this pipe is and take it into account in the risk analyses required by IM regulations.

PHMSA has also modified this part to include rural low-stress pipelines not generally subject to the safety requirements of Part 195. Section 195.48, added by rulemaking on June 3, 2008 (73 FR 31634), imposed the reporting requirements of Subpart B, including the requirement to submit annual reports, on operators of these pipelines. These reporting requirements were necessary so that PHMSA could collect data for the second phase of its rulemaking addressing rural low-stress pipelines. The data must be segregated so that it can be used for this purpose. The changes to Part J accommodate reporting by these new reporting operators and PHMSA's data needs.

Part K—Miles of Regulated Gathering Lines

API and AOPL would clarify that the first row in this part requires reporting of pipelines less than "or equal to" 20% SMYS. They would also delete the row for non-steel pipe operating at greater than 125 psi, since non-steel pipe is not allowed in hazardous liquid pipeline systems.

Response

PHMSA agrees that the first row should be "less than or equal to" 20% SMYS to be consistent with the definition of regulated gathering lines and has revised the form accordingly. PHMSA has not deleted reference to non-steel pipeline operating above 125 psi. The regulations acknowledge that some pipe of this type may exist within gathering pipeline systems (*see* 195.11(a)(3)(ii)).

Part L—HCA-Affecting Segment Miles of Pipe by Type of HCA

API and AOPL recommended revising this part to report the total onshore and offshore HCA miles and not miles by HCA type. API and AOPL contended that operators do not keep data on mileage by HCA type given that all types are treated the same within an IM program.

Response

PHMSA considers that the mileage of pipeline that could affect HCAs of various types is important to its ability to analyze risks. PHMSA also considers that this data should have value for operators performing risk analyses required by IM requirements. PHMSA has retained this part as proposed.

Part M—Breakout Tanks

API and AOPL requested that we revise this part to allow operators to alternatively report information on breakout tanks to either to the NPMS or on the annual report.

Response

We considered the past practice of allowing the option of filing breakout tank information via either the annual report or via the NPMS and determined that this option causes potential ambiguities in the data. Accordingly, we are eliminating the option to file this information via NPMS.

Instructions

API and AOPL noted that the instructions need to address electronic filing and the process for applying for alternate reporting methods. API and AOPL also suggested that the instructions refer to Appendix A of Part 195 for examples of inter- and intra-state pipelines and that the definitions in the instructions be made consistent with those used for accident report forms.

The instructions for Part G instruct reporting parties to compare the total completed and scheduled assessment mileage to the mileage reported in Part B, to identify any discrepancies, and to submit corrections via a supplemental report, as needed. API and AOPL contended that this could be interpreted to require correction of data reported in prior years based on current-year data. API and AOPL requested that PHMSA clarify its intent because this could misrepresent the IM data collected for prior years.

Response

PHMSA has revised the instructions to address the requirements to apply for non-electronic filing and to refer to Appendix A to Part 195 for further information on determining inter- and intrastate pipeline systems.

PHMSA has also clarified the instructions for Part G to explain that supplemental reports should not be submitted for prior years based on current-year data. Errors in prior year reporting that may be identified as a result of collecting and reviewing data for a new annual report should be addressed by submitting a supplemental report for the appropriate year.

Comments on the Safety-Related Condition Form

General Comment

NiSource suggested revising the form to allow for supplemental reports to address resolution of a condition or correction of previously-reported information.

Part C—Condition Information

Atmos and TPA noted that reporting the location of a condition by street address is not always appropriate and that other means of reporting conditions in rural areas should be provided. IUB agreed, noting that determining location by government land survey system (*e.g.,* township, section, range) is often most practical in the Midwest. Spectra commented that a single-point location is often inadequate to define the location of a condition that extends over some portion of a pipeline and suggested defining the location as the center of the condition or allowing for designation of endpoints.

Part D—Description of Condition

Atmos noted that a space is needed to report the percent blend for biofuels, as specified in the instructions. NAPSR suggested that CO_2 transported as a gas be added as a commodity transported in light of forthcoming carbon sequestration projects.

Instructions

Atmos commented that the instructions need to address electronic reporting and the requirements to apply for alternate reporting methods. Atmos and TPA also noted that the proposed instructions do not correlate to the proposed form, sections are in different order, and the instructions contain references that do not match the form. NAPSR requested that the instructions define synthetic gas.

Response

After considering these comments and evaluating its own information needs, PHMSA has decided to withdraw the proposed safety-related condition report and associated changes to §§ 191.25 and 195.56. PHMSA will continue to evaluate its needs and may, again, propose changes to requirements for submitting safety-related condition reports and the information to be included in such reports.

Comments on LNG Annual Report Form

General Comments

AGA, NiSource, INGAA, and Southern LNG (SLNG) commented that much of the data that would be reported on this form duplicates data currently submitted semi-annually to FERC, to the U.S. Coast Guard (USCG), or to PHMSA as a result of incidents. MidAmerican noted that terminology is inconsistent between this form and the LNG incident report form. MidAmerican also cautioned that "incidents" should not be referred to as "events." BG&E contended that this information is unnecessary given that LNG facilities are static and do not expand or change over time as do pipelines.

Part B—System Description

MidAmerican questioned the relationship of information across a given row of this part. They noted that plants can be installed on different dates, in different states, and can have significantly different storage capacities. MidAmerican also noted that this part of the proposed form included an apparent formatting error in that lines denoting rows in the table do not extend across all columns.

Part C—Releases in Past Year From Incidents and Safety-Related Conditions

BG&E contended that PHMSA should not collect this information on annual reports because some of it relates to economic issues (*e.g.,* insulation performance), rather than to safety issues. BG&E recommended that information related to incidents should be collected via the incident report form rather than annually. MidAmerican suggested we reformat this part because it is difficult to follow for operators trying to categorize releases by cause.

Part D—Other Events

AGA, NEGas and NWN recommended deleting this part. These commenters noted that other events are, by definition, not incidents. At most they are "near miss" events of limited relationship to safety and about which it will be difficult to collect consistent data. MidAmerican, NWN, and DOMAC cautioned that events reported on incident reports should not be reported again on this form, contending that summaries prepared for a different form at a different time are almost certain to result in confusion and apparent inconsistencies. MidAmerican, SWGas, and Paiute noted that this part is vague and needs clarification; they commented that several of the listed events appear to be subsets of emergency shutdown. NiSource and DOMAC recommended deleting rollovers and security breaches because these are not safety-significant events. MidAmerican maintained that both terms require better definition, noting that LNG is in constant rollover in tanks due to thermal gradients and suggesting that false activations of security systems/detectors should not be included as security breaches.

Instructions

TPA noted that the instructions need to address electronic filing and the requirements to apply for alternate reporting methods.

Response

Many LNG facilities under PHMSA jurisdiction do not fall under the jurisdiction of either FERC or USCG and do not report to those agencies. PHMSA thus cannot rely on data reported to those agencies for a complete understanding of the LNG facilities for which it is responsible. PHMSA understands that LNG facilities experience less year-to-year change than do pipeline facilities and that it would be an unnecessary burden for LNG facility operators to report the same data on consecutive year's forms. PHMSA has revised the LNG annual report form so that operators may report there has been no change from the data reported in the prior year. In that event, operators need not complete the remainder of the form.

PHMSA agrees that there was a formatting error in Part B of the form that was posted in the docket for comment. Lines denoting rows within this part should have extended across all columns, but did not. PHMSA has revised the format of Part B to improve clarity. PHMSA considers that this change also resolves the apparent confusion about reporting of dates, locations, capacities, etc., as these now clearly relate to individual facilities.

PHMSA has also revised the final form to change the formatting of Parts C and D. As proposed, these parts were in parallel columns, which appear to have caused confusion. In the revised form, these parts each extend across the entire form, which improves clarity. PHMSA does not agree that events to be reported in Part C (*e.g.,* insulation performance) are solely economic issues with no safety significance. Events to be reported in Part C are releases of gas or LNG that result from these causes. Releases may have safety significance and are appropriately of interest to PHMSA.

PHMSA agrees that events that have been reported as incidents should not be reported again on the annual report, and has revised Part D to eliminate categories that duplicate reportable incidents. PHMSA does not agree, however, that Part D should be deleted because none of the events is of safety significance. The remaining events do not reach the threshold of reporting as incidents or safety-related conditions, but do represent safety issues. They include, for example, situations that would have been reported as safety-related conditions had they not been corrected before the report of such a condition was required. (The safety significance of the conditions is the same as safety-related conditions. The only difference is time to repair). It is important to trend these safety events. Though individually of less significance, trends in their occurrence could reveal safety problems requiring additional regulatory attention. PHMSA has retained "rollover" as an event to be reported in Part D. PHMSA disagrees that LNG is in constant rollover. PHMSA agrees that blending and mixing routinely occur within LNG tanks, but this does not constitute rollover. Rollover is a term commonly understood within the LNG industry to refer to an event in which significant stratification has occurred within a tank and, as a result, significant quantities of liquefied gas suddenly relocate due to differences in density. Rollovers have resulted in damage to storage facilities and are safety significant events for LNG carriers and their unloading operations at import terminals. PHMSA recognizes that improved designs have significantly reduced the frequency of rollover occurrence, but considers events that do occur to be significant and to require reporting. PHMSA has also retained security breaches as an element to be reported in Part D. PHMSA does not consider it necessary to explicitly exclude false activations of security systems given that element to be reported is an actual breach rather than any activation of a security alarm system.

PHMSA has revised the instructions to reflect the requirements to apply for an alternate (*i.e.,* non-electronic) reporting method.

Comments on the LNG Incident Report Form

Terminology

AGA, NWN, and NEGas noted that some terms used are not applicable to LNG operations but seem, rather, to be associated with pipelines (*e.g.,* rupture of previously damaged pipe).

Response

PHMSA has revised the form and instructions to more accurately refer to LNG facilities and assure that requested elements are relevant to LNG.

Part B—System Description

DOMAC recommended that the on-line reporting system automatically populate this information with the operator having an opportunity to override or change as needed, and that information being collected for the OPID Registry should make this practical. BG&E commented that operational information is of limited relevance for incidents and suggested deleting this part.

Response

PHMSA is not deleting this part. PHMSA agrees that information in the OPID Registry and reported on annual reports should allow this part to be automatically populated when operators complete an incident report form electronically. We will configure the on-line system to do so. At the same time, some information may change and not yet have been reported to the Registry or NPMS. For example, the status of a facility may change. A mobile facility's location may be different than originally reported. For OPIDs with multiple LNG facilities, the electronic system will be unable to identify the particular facility involved in the incident and will populate data for all facilities. The electronic system will thus afford operators the opportunity to change information that is automatically populated, including deleting information for facilities not involved in the incident. This practice will minimize the burden for completing this information, which could prove useful in understanding and following up on incidents.

Part C—Consequences

DOMAC suggested revising the form to accommodate the possible situation that no evacuation was necessary and that the area was not unsafe, in which case there would be no elapsed time to make the area safe.

Response

PHMSA has revised the form to replace the question concerning elapsed time until the area was made safe to one asking for a timeline of the incident. This avoids the implication that the situation was "unsafe." PHMSA has retained reporting for evacuations. We have revised the instructions to require that operators complete this information based on their own knowledge or based on reports by police, fire or other emergency responder. If no evacuation was needed, operators enter zero. If an estimate is not possible, operators are requested to describe why in the narrative portion of the form. Evacuation information is collected in this same manner for pipeline incidents.

Part D—Origin of Gas Leak/Problem

DOMAC suggested that "gas leak" be replaced with "release," noting that a release may have been in liquid form. BG&E recommended deleting questions related to distributed control systems (DCS), since such systems are not required, the information is of limited value, and it will be burdensome to collect. DOMAC agreed that information concerning DCS systems would be of limited value, noting that such systems do not detect all hazards (*e.g.,* fire).

TPA commented that the list in question 1 of gases potentially involved is unnecessary given that the form is intended for LNG facilities only.

DOMAC suggested revising the title of question 2 in this part from "leak detection" to "hazard detection." DOMAC also suggested reorganizing the form to place this part before Part C; since an incident begins with a release it would be logical to begin data collection with the origin of the release rather than its consequences.

Response

PHMSA does not agree that references to DCS should be deleted. PHMSA has revised this part to address "computerized control systems," encompassing computer-based control systems that may be referred to by terms other than DCS. PHMSA recognizes that computerized control systems are not required to be installed in LNG facilities, but also notes that many facilities use such systems. It is important for PHMSA to understand how useful these systems are in identifying incidents. The information required for computerized control systems is very limited—whether one was in place and whether it initially detected the event—and thus not burdensome to report.

PHMSA has retained the list of gases in question D1. The list simply asks whether the incident originated with natural gas, LNG or "other flammable gas." Other gases are used in liquefaction processes and could be the origin of events that escalate to incidents. The definition of an incident in § 191.3 refers to events resulting in reportable consequences due to a release of "refrigerant gas," which may include other flammable gases.

PHMSA has not re-ordered the form to put Part D before Part C. While it is true that most incidents involve a release, the definition also includes emergency shutdowns and events that the operator considers significant even though they do not meet the other specified criteria. These other significant events may not involve a release (*e.g.,* security breach). Part C reports consequences, which is why the event constituted an incident in the first place. PHMSA considers that the order of these sections is appropriate.

Part E—Suspected Causes

DOMAC commented that this part appears to be taken from a pipeline context and does not fit the LNG environment.

Response

We have revised this part to be more applicable to the LNG environment.

Instructions

DOMAC noted that the instructions refer to Part 192 vs. Part 193 and will require significant revision. TPA suggested that the instructions for Part D, question 2, refer to "how was the release detected" instead of "where the leak/problem occurred." TPA also noted that the instructions need to address the requirements for reporting by methods other than electronic reporting.

Response

PHMSA has revised the instructions to be consistent with the form as modified. The instructions include an explanation of how an operator must apply to use alternate reporting methods. PHMSA notes its strong preference for electronic reporting, which will be the required method for all reports addressed in this rule. Allowance is made for alternative methods when operators demonstrate that electronic reporting involves undue burden. PHMSA will review requests for use of alternate methods critically to assure that electronic reporting would be truly burdensome before approving an alternative.

Comments on Offshore Pipeline Condition Report Form

API and AOPL noted that the form does not accommodate the likelihood that inspections will be completed with no exposed pipe identified.

Response

As discussed above, PHMSA is withdrawing this proposed form.

V. Advisory Committee Recommendations

The Technical Pipeline Safety Standards Committee (TPSSC) and the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) considered the July 2, 2009, NPRM to revise the reporting requirements in the pipeline safety regulations at a joint meeting on December 9, 2009. A transcript of this meeting is available in the docket.

The TPSSC and THLPSSC have been established by statute to evaluate proposed pipeline safety regulations. Each committee has an authorized membership of 15 individuals with membership evenly divided between the government, industry, and the public. Each member of these committees is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety regulations.

Each committee voted to support the proposed rule, subject to comments made during committee discussion. The amendments adopted in this final rule are consistent with the recommendations of the committees except for the issue of the change in the definition of an incident and the volume of measure for release of gas. The committees recommended that PHMSA adopt a threshold of 10,000 Mcf and not the 3,000 Mcf threshold proposed in the NPRM. For the reasons stated in Section 2, "Changing the definition of an 'Incident' for gas pipelines" of the preamble, PHMSA has adopted a threshold of 3,000 Mcf. Committee comments generally were consistent with written comments filed by other commenters discussed above.

VI. Section-by-Section Analysis

1. Section 191.1—This Section is amended to include in the scope of Part 191 regulated rural gathering lines. Rural onshore regulated gathering lines were defined by a final rule published March 15, 2006 (71 FR 13289), but that rule unintentionally failed to include these newly regulated lines in the reporting requirements of Part 191.

2. Section 191.3—This Section is amended to revise the definition of an incident for gas pipelines and LNG facilities. As discussed elsewhere in this document, principal changes include the addition of a criterion defining as an incident an unintentional release of gas that results in estimated gas loss of 3 million cubic feet or more. The criterion defining an incident on the basis of $50,000 property damage is correspondingly revised to omit consideration of the cost of gas lost. This amendment also clarifies that the activation of an emergency shutdown system at an LNG facility for reasons other than an actual emergency does not constitute an incident.

3. Sections 191.7 and 195.58—These Sections are amended to require that all required reports, except safety-related condition reports and offshore condition reports, be submitted electronically unless an operator has demonstrated that electronic reporting would pose an undue burden and hardship and has obtained PHMSA approval to report by other means.

4. Section 191.9—This Section is amended to remove the exclusion for LNG facilities that are part of distribution pipeline systems. Submission of incident reports for these facilities will now be required.

5. Section 191.11—This Section is amended to remove the exclusion for LNG facilities. Submission of annual reports for these facilities will now be required.

6. Section 191.15—This Section is amended to add the requirement that

operators of LNG facilities submit written incident reports.

7. Section 191.17—This Section is amended to add the requirement that operators of LNG facilities submit annual reports.

8. Sections 191.19 and 195.62—These Sections described how to obtain copies of required forms. The Sections are being removed, because all reports for which forms have been approved will now be required to be made electronically. Copies of the forms on which the electronic reporting system is based will continue to be available on PHMSA's Web site.

9. Sections 191.21 and 195.63—These Sections are amended to include new forms that are included under OMB Control Number 2137–0522 for gas pipelines and to add new OMB control numbers for forms associated with hazardous liquid pipelines.

10. Sections 191.22 and 195.64—These Sections are added to create a National Registry of Pipeline and LNG Operators. Operators will use the Registry to obtain and change an OPID. Operators who already have one or more OPIDs are required to validate the information in PHMSA's records currently associated with those OPIDs within six months. Operators are required to notify PHMSA, via the Registry, of certain changes that affect the facilities associated with an OPID. Operators are also required to use their assigned OPID for all reporting requirements and for submissions to the NPMS. Operators are also required to notify PHMSA of changes within safety programs managed in common across multiple OPIDs (*e.g.,* where a company operates multiple pipelines) that affect the OPID the operator considers "primary" for that program (generally representing which operating entity is responsible for the program).

PHMSA has previously obtained this information from operators informally, usually from an operator's compliance personnel, as this information is needed for inspection planning. PHMSA will also use this information to analyze safety program performance and to identify trends.

11. Section 192.945—This Section is amended to reflect the integration of reporting of IM performance measures for gas transmission pipelines into the annual report. Semi-annual reporting of IM performance measures is no longer required.

12. Section 192.951—This Section is amended to require that all reports required by Subpart O of Part 192 be submitted electronically in accordance with revised § 191.7.

13. Section 193.2011—This Section is amended to require that LNG facility operators submit annual reports and reports of incidents and safety-related conditions in accordance with the requirements of Part 191.

15. Section 195.48—This Section specifies the scope of hazardous liquid pipelines subject to the reporting requirements of Subpart B of Part 195. Exceptions from portions of the annual report for pipelines not otherwise subject to Part 195 have been revised and moved to § 195.49.

15. Section 195.49—This Section is amended to require that some parts of the hazardous liquid pipeline annual report form (designated on the form) must be completed separately for each state a pipeline traverses.

16. Section 195.52—This Section is amended to require that hazardous liquid pipeline operators have a written procedure for calculating an initial estimate of the amount of product released in an accident. The amended Section also requires that operators provide an additional telephonic report if significant new information becomes available during the emergency response phase.

17. Section 195.54—This Section is revised to remove the option to submit a facsimile of the PHMSA form because all reports must now be submitted electronically.

VII. Regulatory Analyses and Notices

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The amendments to the data collections requirements of the Pipeline Safety Regulations addressed in this rulemaking are issued under this authority and address NTSB and GAO recommendations. This rulemaking also carries out the mandates regarding incident reporting requirements under section 15 of the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (Pub. L. No. 109–468, Dec. 29, 2006).

Executive Order 12866 and DOT Policies and Procedures

This final rule is not a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735) and, therefore, was not reviewed by the OMB. This final rule is not significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034).

Overall, the costs of the final rule are approximately $1.6 million per year. The present value of this cost over ten years at a seven percent discount rate is approximately $11 million. Those costs cover changes to the 49 CFR to enhance general data and data management improvements for pipelines.

The average of the present value of net benefits over ten years at a seven percent discount rate is approximately $73 million.

The benefits of the final rule enhance PHMSA's ability to understand, measure, and assess the performance of individual operators and industry as a whole; integrate pipeline safety data in a way that will allow a more thorough, rigorous, and comprehensive understanding and assessment of risk; expand and simplify existing electronic reporting by operators; improve the data and analyses PHMSA relies on to make critical, safety-related decisions; and facilitate PHMSA's allocation of inspection and other resources based on a more accurate accounting of risk.

A comparison of the benefits and costs of the rule results in positive net benefits. The present value of net benefits (the excess of benefits over costs) for the final rule is approximately $73 million using a seven percent discount rate. A copy of the regulatory evaluation is available for review in the docket.

Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980, as amended, requires Federal agencies to conduct a separate analysis of the economic impact of rules on small entities. The Regulatory Flexibility Act requires that Federal agencies take small entities' concerns into account when developing, writing, publicizing, promulgating, and enforcing regulations. The requirements imposed in this final rule will affect hazardous liquid, natural gas pipelines (distribution and transmission), and LNG facility operators.

The Small Business Administration (SBA) size standards for hazardous liquid operators are companies with less than 1,500 employees, including employees of parent corporations. The SBA size standards are $6.5 million in annual revenues for the natural gas transmission pipeline industry and 500 employees for the natural gas distribution industry. PHMSA has reviewed the data it collects from the hazardous liquid pipeline industry and has estimated there are approximately 220 small hazardous liquid pipeline operators, 475 natural gas transmission pipeline operators, and 54 LNG facility operators that may be considered small entities. The rule could result in a significant adverse economic impact on small entities if the estimated average annual costs attributed to the rule exceed one percent of their annual revenues. Since the average cost of the rule for each small pipeline operator affected by the rule is modest—estimated at $6,691 for each hazardous liquid pipeline operator, $461 for each natural gas transmission operator and $913 for each LNG facility operator—PHMSA concludes that there will not be a significant impact on a substantial number of small pipeline operators.

Executive Order 13175

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

Paperwork Reduction Act

This final rule has resulted in revisions to several information collections that have either been approved by OMB, or have been submitted to OMB for approval. The following list contains the approved information collection and its approval information:

	OMB Control No.	Info collection title	Expiration date	Approved burden hours
1	2137–0522	Incident and Annual Reports for Gas Pipeline Operators	11/30/2011	53,627

The following list contains the information collections that have been submitted to OMB for approval. When approval is received from OMB on these information collections, PHMSA will publish a notice announcing their approval in the **Federal Register**:

	OMB Control No.	Info collection title
1	2137–0047	Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting
2	2137–0614	Pipeline Safety: New Reporting Requirements for Hazardous Liquid Pipeline Operators; Hazardous Liquid Annual Report.

Unfunded Mandates Reform Act of 1995

This final rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It would not result in costs of $100 million, adjusted for inflation, or more in any one year to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the final rule.

National Environmental Policy Act

PHMSA analyzed the proposed rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500–1508), and DOT Order 5610.1C, and preliminarily determined the action would not significantly affect the quality of the human environment. We received no comment on this determination. Therefore, we conclude that this action will not significantly affect the quality of the human environment.

Executive Order 13132

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

Executive Order 13211

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

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 in the **Federal Register** published on April 11, 2000 (70 FR 19477) or visit *http://dms.dot.gov.*

List of Subjects

49 CFR Part 191

Pipeline Safety, Reporting and recordkeeping requirements.

49 CFR Part 192

Pipeline safety, Fire prevention, Security measures.

49 CFR Part 193

Pipeline safety, Fire prevention, Security measures, and Reporting and recordkeeping requirements.

49 CFR Part 195

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

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

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

■ 1. The authority citation for Part 191 continues to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, and 60124, and 49 CFR 1.53.

■ 2. In § 191.1, paragraph (b)(4) is revised to read as follows:

§ 191.1 Scope.

* * * * *

(b) * * *

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this subchapter); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

■ 3. In § 191.3, the definition of "Incident" is revised to read as follows:

§ 191.3 Definitions.

* * * * *

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;

(iii) Unintentional estimated gas loss of three million cubic feet or more;

(2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

* * * * *

■ 4. In § 191.5, the section heading and paragraph (b) introductory text are revised to read as follows:

§ 191.5 Immediate notice of certain incidents.

* * * * *

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

* * * * *

■ 5. Section 191.7 is revised to read as follows:

§ 191.7 Report submission requirements.

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

(b) *Exceptions.* An operator is not required to submit a safety-related condition report (§ 191.25) or an offshore pipeline condition report (§ 191.27) electronically.

(c) *Safety-related conditions.* An operator must submit concurrently to the applicable State agency a safety-related condition report required by § 191.23 for intrastate pipeline transportation or when the State agency acts as an agent of the Secretary with respect to interstate transmission facilities.

(d) *Alternative Reporting Method.* If electronic reporting imposes an undue burden and hardship, an 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, PHP–20, 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* or 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.

■ 6. In § 191.9, paragraph (c) is revised to read as follows:

§ 191.9 Distribution system: Incident report.

* * * * *

(c) Master meter operators are not required to submit an incident report as required by this section.

■ 7. Section 191.11 is revised to read as follows:

§ 191.11 Distribution system: Annual report.

(a) *General.* Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *Not required.* The annual report requirement in this section does not apply to a master meter system or to a petroleum gas system that serves fewer than 100 customers from a single source.

■ 8. Section 191.15 is revised to read as follows:

§ 191.15 Transmission systems; gathering systems; and liquefied natural gas facilities: Incident report.

(a) *Transmission or Gathering.* Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(b) *LNG.* Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(c) *Supplemental report.* Where additional related information is obtained after a report is submitted under paragraph (a) or (b) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

■ 9. Section 191.17 is revised to read as follows:

§ 191.17 Transmission systems; gathering systems; and liquefied natural gas facilities: Annual report.

(a) *Transmission or Gathering.* Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2.1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(b) *LNG.* Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1 This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

§ 191.19 [Removed]

■ 10. Section 191.19 is removed.

■ 11. Section 191.21 is revised to read as follows:

§ 191.21 OMB control number assigned to information collection.

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137–0522

Section of 49 CFR Part 191 where identified	Form No.
191.5	Telephonic.
191.9	PHMSA 7100.1, PHMSA 7100.3.
191.11	PHMSA 7100.1–1, PHMSA 7100.3–1.
191.15	PHMSA 7100.2.
191.17	PHMSA 7100.2–1.
191.22	PHMSA 1000.1.

■ 12. Section 191.22 is added to read as follows:

§ 191.22 National Registry of Pipeline and LNG Operators.

(a) OPID Request. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain on OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with § 191.7.

(b) OPID validation. An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

(c) Changes. Each operator of a gas pipeline, gas pipeline facility, LNG plant or LNG facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov* of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

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

(iii) Construction of a new LNG plant or LNG facility.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter; or

(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter.

(d) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

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

■ 13. The authority citation for Part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

■ 14. In § 192.945, paragraph (a) is revised to read as follows:

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by § 191.17 of this subchapter.

■ 15. Section 192.951 is revised to read as follows:

*   *   *   *   *

§ 192.951 Where does an operator file a report?

An operator must file any report required by this subpart electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with § 191.7 of this subchapter.

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

■ 16. The authority citation for Part 193 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60103, 60104, 60108, 60109, 60110, 60113, 60118, and 49 CFR 1.53.

■ 17. Section 193.2011 is revised to read as follows:

§ 193.2011 Reporting.

Incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities must be reported in accordance with the requirements of Part 191 of this subchapter.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

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

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118, and 49 CFR 1.53.

■ 19. Section 195.48 is revised to read as follows:

§ 195.48 Scope.

This subpart prescribes requirements for periodic reporting and for reporting of accidents and safety-related conditions. This subpart applies to all pipelines subject to this part and, beginning January 5, 2009, applies to all rural low-stress hazardous liquid pipelines.

■ 20. Section 195.49 is revised to read as follows:

§ 195.49 Annual report.

Each operator must annually complete and submit DOT Form PHMSA F 7000–1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state.

■ 21. Section 195.52 is 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, the operator of the system must give notice, in accordance with paragraph (b) of this section, of any failure that:

(1) Caused a death or a personal injury requiring hospitalization;

(2) Resulted in either a fire or explosion not intentionally set by the operator;

(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

(b) Information required. Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202–267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Name, address and identification number of the operator.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) Initial estimate of amount of product released in accordance with paragraph (c) of this section.

(7) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

(c) Calculation. A pipeline operator must have a written procedure to calculate and provide a reasonable initial estimate of the amount of released product.

(d) New information. An operator must provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response phase of a reported event at the earliest practicable moment after such additional information becomes known.

■ 22. In § 195.54, paragraph (a) is revised to read as follows:

§ 195.54 Accident reports.

(a) Each operator that experiences an accident that is required to be reported under § 195.50 must, as soon as practicable, but not later than 30 days after discovery of the accident, file an accident report on DOT Form 7000–1.

* * * * *

■ 23. Section 195.58 is revised to read as follows:

§ 195.58 Report submission requirements.

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

(b) *Exceptions.* An operator is not required to submit a safety-related condition report (§ 195.56) or an offshore pipeline condition report (§ 195.67) electronically.

(c) *Safety-related conditions.* An operator must submit concurrently to the applicable State agency a safety-related condition report required by § 195.55 for an intrastate pipeline or when the State agency acts as an agent of the Secretary with respect to interstate pipelines.

(d) *Alternate Reporting Method.* 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, PHP–20, 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.

§ 195.62 [Removed]

■ 24. Section 195.62 is removed.

■ 25. Section 195.63 is revised to read as follows:

§ 195.63 OMB control number assigned to information collection.

The control numbers assigned by the Office of Management and Budget to the hazardous liquid pipeline information collection pursuant to the Paperwork Reduction Act are 2137–0047, 2137–0601, 2137–0604, 2137–0605, 2137–0618, and 2137–0622.

■ 26. Section 195.64 is added to read as follows:

§ 195.64 National Registry of Pipeline and LNG Operators.

(a) OPID Request. Effective January 1, 2012, each operator of a hazardous liquid pipeline or pipeline facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID or a change to an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with § 195.58.

(b) OPID validation. An operator who has already been assigned one or more OPID by January 1, 2011 must validate the information associated with each such OPID through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

(c) Changes. Each operator must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at *http://*

opsweb.phmsa.dot.gov, of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

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

(iii) Construction of a new pipeline facility.

(2) An operator must notify PHMSA of any following event not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (*e.g.,* company, municipality) responsible for operating an existing pipeline, pipeline segment, or pipeline facility;

(iv) The acquisition or divestiture of 50 or more miles of pipeline or pipeline system subject to this part; or

(v) The acquisition or divestiture of an existing pipeline facility subject to this part.

(d) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

Issued in Washington, DC, on November 9, 2010, under the authority delegated in 49 CFR Part 1.

Cynthia L. Quarterman,

Administrator.

[FR Doc. 2010–29087 Filed 11–24–10; 8:45 am]

BILLING CODE 4910–60–P