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DOT Docket Management System: U.S. Department of Transportation
Docket Operations, M-30
Room W12-140
1200 New Jersey Avenue, S.E.
Washington, DC 20590-0001

VIA FEDERAL E-RULEMAKING PORTAL (www.regulations.gov)

Re: Docket No. PHMSA-2008-0291: *Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements*

Good afternoon:

Pursuant to the notice of proposed rulemaking ("Proposed Rule") issued in the referenced docket by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") on July 1, 2009, and published in the July 2, 2009, issue of the *Federal Register*,[1] the Interstate Natural Gas Association of America ("INGAA") submits the following comments.

INGAA is a non-profit trade association that represents the interstate natural gas transmission pipeline industry. INGAA's members operate over two thirds of the nation's natural gas transmission pipeline mileage and represent almost one quarter of the natural gas transmission pipeline entities reporting to PHMSA. Their interest in the NOPR is self-evident.

EXECUTIVE SUMMARY

INGAA appreciates PHMSA's interest in improving its incident, infrastructure and performance database. Consistent with this focus, the proposed definition of "incident" should be substantially modified to reflect the central role that risk plays in distinguishing incidents from other events. INGAA urges a number of revisions, and specifically objects to the "lost gas" provision that would make a gas transmission leak a reportable incident once the amount of gas lost exceeds a mere 3,000 Mcf.

INGAA also appreciates PHMSA's interest in establishing and reasonably maintaining a National Registry of Pipeline and LNG Operators. Unfortunately, the proposed regulations governing registry updates do not accord with basic business practices and far exceed similar requirements that have long been imposed by the Federal Energy Regulatory Commission.

The Proposed Rule would revise 49 C.F.R. § 191.25 by eliminating the distinction between discovering a condition and determining that the condition is reportable. No reason was given for eliminating this valuable and sensible distinction, and INGAA urges the distinction be preserved. Elsewhere, the Proposed Rule would revise 49 C.F.R. § 191.27 without updating the text to reflect significant regulatory changes that have occurred since the regulation was first promulgated in 1991. INGAA urges PHMSA take this opportunity to update the reporting deadline in 49 C.F.R. § 191.27 to reflect current regulations.

Finally, INGAA urges a number of revisions to the proposed annual report and accompanying instructions. INGAA presents these suggested revisions not only in the text of these comments, but also in a marked-up copy of the annual report, which is being filed with these comments as Appendix A. Given the number and nature of the suggested revisions, INGAA urges PHMSA to provide a supplemental public notice, giving the public 30 days to comment on its proposed annual report as further

[1] 74 Fed. Reg. 31675.

revised to reflect INGAA's comments and the comments of others. The supplemental notice and opportunity to comment would mirror the procedures PHMSA is employing with regard to accident reports, and foster an integrated data collection approach. In closing, INGAA notes that integrated management of these data collection initiatives would be substantially enhanced by coordinated implementation, including the use of an appropriate test period, which would allow all of PHMSA's data collection initiatives to be instituted at the start of the same calendar year.

COMMENTS

I. The definition of "incident" should be substantially amended to distinguish incidents from events on the basis of risk.

Events that involve the unintentional release of gas from a natural gas transmission pipeline are disclosed to PHMSA through the annual report.[2] The essential purpose for defining "incident" is to determine when an incident report should be filed. Annual reports can be used to determine trends and patterns. To the extent additional information is needed for in depth trending analysis (that is, analysis beyond the data available in the annual report) the collection of such information should be limited to events that impose a higher actual or potential level of risk.[3] From the origins of incident reports in 1971, the critical factor separating reportable incidents from other events is the risk posed to pipeline operators, PHMSA and the public.

In discussions between PHMSA and INGAA leading up to this rulemaking, the goal was to review the factors for determining that a release of natural gas, at the point and time of the event, caused sufficient risk to classify the event as an incident warranting an incident report (rather than a leak that would be reported on the annual report). A consensus emerged that the main criteria for identifying reportable incidents were whether the release was intentional or unintentional, where the release occurred, the consequences of the release and the amount of natural gas released.

This docket proposes several improvements in the annual report, particularly with regard to the categorization of the causes of events, and INGAA supports these changes. Still, the consensus to distinguish incidents from other events based on risk is not reflected in the presently proposed definition of "incident." As a result, the proposed definition lacks rigor and invites misinterpretation. INGAA therefore recommends the following modifications:

The proposed introductory clause should be amended to read: "Incident means an event that causes:" instead of "Incident means any of the following events:".

Proposed subparagraphs (1)(i)-(iv) describe the consequences of an event rather than the incident. The suggested rephrasing more accurately reflects the role risk causation plays in distinguishing incidents from other events.

Conforming changes would have to be made to proposed paragraphs (1), (2) and (3). In proposed paragraph (1) this would be accomplished by striking "An event that involves". In proposed paragraph (2) this would be accomplished by striking "An event", inserting a comma after "facility" and deleting "that results in" before "an emergency". In proposed paragraph (3) this would be accomplished by striking "An event that is" and inserting "risk" after "significant".

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[2] See 49 C.F.R. § 191.17 (requiring operators to file DOT Form PHMSA 7100.2.1). Data and related information concerning leaks is currently reported in parts C, D and E of the annual report.

[3] For example, incident reports are appropriately used to assess trends in operator performance, which in turn may guide PHMSA in determining its involvement in an incident investigation.

Proposed subparagraph (1)(ii) should be amended to read: "Estimated property damage to the operator and others, or both, of $50,000 or more, excluding cost of gas lost." instead of "Estimated property damage of $50,000 or more, including loss to the operator and others, or both.".

Current regulations define "incident" according to the estimated dollar value of property damage (specifically, "[e]stimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more").[4] Under the Proposed Rule, the language would be changed to "[e]stimated property damage of $50,000 or more, including loss to the operator and others, or both." The obvious intent of this modification is to remove the cost of gas lost from the $50,000 damage threshold, which is understandable since gas costs would now be handled through their own threshold. Unfortunately, the proposed modification to the $50,000 threshold does not completely address the problem in light of a January 3, 1973 advice letter defining "property damage" to include "the estimated cost of gas lost."[5] To lay the matter to rest fully, the $50,000 threshold should be phrased as "estimated property damage to the operator and others, or both, of $50,000 or more, excluding cost of gas lost."

Proposed paragraph (1) should be amended by substituting "an unintentional release" for "a release" and proposed subparagraph 1(iii) should be amended by inserting "unintentional" between "Estimated" and "gas".

Incident reports are intended to identify events where a hazard has been created through an unintentional release of natural gas. When natural gas is intentionally released consistent with standard operation and maintenance practices (*e.g.*, at valves or rupture disks), there are procedures and processes in place to minimize safety concerns. These intentional releases, such as blow downs of pipe sections and station blow downs, should not be reported as incidents no matter how much natural gas released.[6] Inserting "unintentional" in paragraph (1) and subparagraph (1)(iii) clarifies this critical point.

Proposed subparagraph (1)(iii) should be amended by inserting "at the incident location" after "loss".

The safe release of natural gas at a location designed for that purpose does not create a risk and should therefore not be considered an incident. Adding the words "at the incident location" to item (1)(iii) clarifies that the gas loss threshold applies only to losses at locations that are not designed and operated to safely release natural gas.

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[4] 49 C.F.R. § 191.3.

[5] Letter from Joseph C. Caldwell, Director, Office of Pipeline Safety, to D.J. Hendrickson, Director, Pipeline Safety Division, Indiana Public Service Commission, Jan. 3, 1973. As illustrated by the January 1973 letter, "property damage" also includes the "cost of material, labor and equipment to repair" a leak. For example, when an operator employs a contractor to "pump down" a valve station, the contractor's fee is included in the repair cost and, ultimately, the property damage subject to the $50,000 threshold.

[6] If a blow down system correctly activates after receiving a signal, the release should be considered intentional and not be reported. Conversely, a malfunction should be considered an unintentional release and reported.

Proposed subparagraph (1)(iii) should be amended so that for events on natural gas transmission pipelines the triggering volume of gas loss would be 20,000 Mcf, as opposed to the 3,000 Mcf level currently proposed.

The current definition of "incident" identifies events that have been viewed as having significant consequences:

- *Fatality or injury*
- *Property damage over $50,000*
- *Explosion or fire*
- *Events that are "significant" in eyes of the operator*

The Proposed Rule would add two criteria to capture "near miss" events that had the **possibility** of consequences but where the possible consequences did not occur:

- *LNG*
- *Gas loss*

As mentioned above, the occurrence and the cause of these and other events are already reported under the annual report. The main advantage of continuing to report these events as incidents is to maintain continuity and with former incident reports, which did not have the improved clarity of the actual consequences that the new forms provide.

The LNG criterion reflects a heightened public concern about LNG plants. Still, the LNG criterion does not necessarily reflect a risk concern because it is the reporting of the correct operation of safety equipment at an LNG facility. As was mentioned above, the main benefit of retaining this criterion is continuity of data collection.

The second criterion "gas loss" is now separated from the property damage criterion. As a result, a "gas loss" incident does not reflect an actual consequence of concern, but rather a "near miss". The amount of gas lost during an event is not a significant indicator of the risk by itself.

For hazardous liquid pipelines, the total amount of product loss is a good indicator of the severity of the consequences, which are primarily environmental. In contrast, the potential consequences of a natural gas transmission pipeline event is less a function of the amount of gas lost than the rate of gas loss and its relative proximity to people and property. INGAA realizes that it would be difficult to adopt this concept of potential consequences in this rulemaking, and that adopting this concept would impair continuity across the PHMSA data base and other INGAA filings. Accordingly, agrees that, for trending purposes, a volume threshold should be included within the definition of "incident." INGAA objects, however, to the proposed threshold level.

Under the Proposed Rule, the definition of "incident" would be amended to include "an event . . . that results in . . . estimated gas loss of 3,000 million cubic feet or more."[7] INGAA assumes PHMSA intended the proposed threshold to be 3,000 Mcf, or thousand cubic feet, consistent with its discussion of this provision in the regulatory preamble.[8]

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[7] Proposed Rule, 74 Fed. Reg. at 31683 (text of proposed 40 C.F.R. § 191.3(1)(iii)).

[8] *Id*. at 31677.

If the volume of gas lost is to be considered an independent basis for classifying an event as an incident, the threshold should be set at a level that captures roughly the same events that are reported as incidents currently. As a starting point for analysis, since the triggering dollar threshold was $50,000 (including property damage) the triggering volume should be set at a level that at least comes close to equaling $50,000 worth of natural gas.

As INGAA stated in its earlier petition, the appropriate level of gas loss for events on natural gas transmission pipelines continues to be 20,000 Mcf. The $50,000 property damage trigger was set in 1984, and has not been updated since. For purposes of data continuity, the gas loss trigger should be tied to the average gas price in 1984, which was $2.50 per Mcf. At 1984 prices, a $50,000 gas loss equates to 20,000 Mcf.

Approaching the gas loss threshold from a different perspective, one of the primary goals of this rule change as documented by INGAA's original petition and the subsequent GAO report was to remove the volatility of the incident reporting criteria because of the price of natural gas. The Energy Information Administration ("EIA") reports that on August 19, 2009, the natural gas spot price, measured at the Henry Hub, was $3.02 per million British thermal units,[9] which converts to approximately $3.11 per Mcf.[10] At this price, a 3,000 Mcf threshold translates into less than $10,000 in lost value, less than one-fifth the current dollar threshold for defining an incident. Using the current Henry Hub spot price would set the threshold at over 16,000 Mcf, which is at least somewhat in line with the property damage criterion.[11]

In addition, INGAA analyzed the reportable incidents for 2008 and determined (through the use of the various reported fields in the reports) that the majority of these reported incidents would have been reported to PHMSA because of they would have met one of the other triggering criteria, *i.e.*, injury or fatality, fire, or property damage of $50,000 or more. Of the remaining events, many would have been reported under INGAA's proposed 20,000 Mcf criteria. (For example, leaks larger than 1 inch.) The remaining events, which were reported as reportable incidents but did not appear to exceed the INGAA 20,000 Mcf criteria, were pinholes that were low risk (the operator did not determine them to be a significant risk) and therefore more appropriately recorded in the annual report.

Based on this analysis, adopting the proposed 3,000 Mcf threshold will cause a significant number of the low risk pinhole and fitting leaks, which are presently reported in the annual report (DOT Form PHMSA F 7000-1.1), would be shifted to the incident report (DOT Form PHMSA F 7000-2). The number of incident reports, and the cost of reporting, will increase sharply,[12] and the incident database, which has proven useful in policy analysis and development, will lose its continuity.

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9 Natural Gas Weekly Update (EIA, Aug. 20, 2009) available at:

http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp

10 As noted by EIA, one Mcf equals 1.031 million Btu on average. Frequently Asked Questions—Natural Gas (EIA) available at:

http://tonto.eia.doe.gov/ask/ng_faqs.asp#ng_conversions

11 The Proposed Rule states that the 3,000 Mcf threshold "more accurately represents the median volume of gas lost reported through transmission incident reports since 2002." Proposed Rule, 74 Fed. Reg. at 31677. Even if this is true, it is irrelevant. The fact that a certain amount of gas is lost (on average) when there is $50,000 or more property damage does not justify using that amount to set a reporting threshold when the only loss is the value of the gas itself.

12 PHMSA's own analysis predicts that an additional 308 incident reports will be filed in the first year because of the criteria change. Pipeline Safety: Pipeline and Liquefied Natural Gas Reporting Requirements; February 2009; Docket ID PHMSA-2008-0291-0009; Page 23

In the Proposed Rule PHMSA argues that the lower gas loss value is necessary to capture gas distribution incidents.[13] An examination of field reports presently on file suggests that a distribution-driven gas loss criterion would have little or no value. Distribution incident reports that were triggered by the $50,000 property loss criterion had an overwhelming bias toward owner or public property damage rather than gas loss. Conversely, gas transmission incident reports triggered by the same criterion had a bias toward gas loss compared with other property damage. While it could be argued that the proposed 3,000 Mcf standard is inappropriate even for events on distribution systems, INGAA does not take a position on this issue.

Proposed subparagraph (1)(iv) should be promoted to a separate paragraph and amended by inserting "intentional or unintentional release of gas that results in an" after "An".

As proposed, an event becomes a reportable incident on the basis of one of four consequences: death or personal injury, property damage, gas loss, or fire. Amendments proposed earlier in these comments would apply the first three consequences only to events involving unintentional releases of gas. The fourth consequence — an unintentional fire — should render an event reportable whether the gas release was intentional or unintentional, *e.g.*, if gas ignites during a blow down.

Conforming changes would have to be made to proposed paragraphs (2) and (3). Proposed paragraph (2) would be redesignated paragraph (3). Proposed paragraph (3) would be redesignated paragraph (4), and the cross-reference in the text of paragraph (4) would be expanded to reference paragraphs (1), (2) and (3).

Proposed paragraph (2), which INGAA would redesignate paragraph (3), should be amended by substituting "a deviation from normal operation, a structural failure, or severe environmental conditions that have the potential to cause harm to people or property, and that result in an emergency shutdown of the facility" for "an emergency shutdown, excluding the activation of emergency shutdown devices for maintenance".

As currently proposed, every emergency shutdown ("ESD") at an LNG facility (except the activation of emergency shutdown devices for maintenance) would qualify as a reportable incident. ESDs may occur without impact to operator personnel, or risk to the public, and without meeting any of the triggering criteria in proposed paragraph (1).[14] For example, the malfunction of an ESD instrumented control device should not be a reportable incident as this presents a potential "operational upset" to the process only. The substitute text for proposed paragraph (2) addresses these issues while maintaining incident status for events that pose an appropriate level of risk.

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[13] Proposed Rule, 74 Fed. Reg. at 31677.

[14] Or, per INGAA's proposed amendments, paragraphs (1) or (2).

As amended per INGAA's recommendations, the definition of "incident" would read as follows (insertions into initially proposed text in bold, deletions from initially proposed text indicated by strike-outs):

Incident means **an event that causes** ~~any of the following events~~:

(1) ~~An event that involves a~~ **An unintentional** 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 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~~ **to the operator and others, or both, of $50,000 or more, excluding cost of gas lost**; **or**

(iii) **(a)** **For events on a gas transmission pipeline, estimated** ~~Estimated~~ **unintentional** gas loss **at the incident location** of **20,000 Mcf** ~~3,000 million cubic feet~~ or more**; or**

(b) **For events on a gas distribution pipeline, estimated unintentional gas loss at the incident location of _______ Mcf or more**.

(2)~~(iv)~~ An **intentional or unintentional release of gas that results in an** explosion or fire not intentionally set by the operator.

(3)~~(2)~~ ~~An event at~~ **At** an LNG plant or LNG facility, ~~that results in~~ **a deviation from normal operation, a structural failure, or severe environmental conditions that have the potential to cause harm to people or property and that result in an emergency shutdown of the facility** ~~an emergency shutdown, excluding the activation of emergency shutdown devices for maintenance~~.

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

II. The proposed list of notifications to PHMSA under the National Registry of Pipeline and LNG Operators contradicts basic business practices and far exceeds the analogous notification standards required by the Federal Energy Regulatory Commission.

As part of creating a National Registry of Pipeline and LNG Operators, the Proposed Rule would require natural gas pipeline operators to provide PHMSA with 60 days advance notice of the following events:

- ✦ A change in the name of the operator;
- ✦ A change in the operating entity responsible for an existing pipeline, pipeline segment, or pipeline facility, or LNG facility;
- ✦ The acquisition or divestiture of 50 or more miles of pipeline or pipeline system regulated by PHMSA;
- ✦ Any rehabilitation, replacement, modification, upgrade, uprate, or update costing $5 million or more;
- ✦ Construction of 10 or more miles of a new gas transmission pipeline or any project involving a pipeline or pipeline facility costing $5 million or more; and

- ✦ The acquisition or divestiture of an existing LNG plant or LNG facility or construction of a new LNG plant or LNG facility.[15]

The vast majority of these changes occur through inter-corporate commercial transactions which, for legitimate business reasons, are negotiated in confidence and announced to the public only after they are consummated. It is simply impossible to provide PHMSA 60 days advance notice. For changes in the name of the operator or the responsible operating entity,[16] notification should be provided to PHMSA when such changes take effect; for acquisitions and divestitures, notification should be provided to PHMSA within 60 days from the closing date of the underlying transaction.

As for pipeline modification and construction, INGAA appreciates PHMSA's interest in keeping the registry reasonably up to date. The Federal Energy Regulatory Commission ("FERC") shares a similar interest in maintaining reasonable track of the construction and modification of the natural gas transmission pipeline grid as well as LNG terminals and facilities. FERC obtains the information it needs through a series of annual reports, and annual reporting is sufficient for PHMSA's needs as well.

Through its blanket certificate authorization procedures,[17] FERC provides "automatic authorization" for pipelines "to make miscellaneous rearrangements of any facility, or acquire, construct, replace, or operate any eligible facility" provided the project cost does not exceed an annually set threshold.[18] The threshold for calendar 2009 is $10,400,000.[19] Every March 31st, each pipeline sends FERC a report describing the facilities in detail,[20] including their location and construction dates.[21] Facility replacements are handled through a similar report pipelines file with FERC every May 1st.[22]

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15 Proposed Rule, 74 Fed. Reg. at 31684 (text of proposed 49 C.F.R. § 191.22(b)(1)-(6)).

16 INGAA has a separate issue with the way one of the registry-reportable events is characterized in the Proposed Rule. As proposed, an operator would have to report "[a] change in the operating entity responsible for an existing pipeline, pipeline segment, or pipeline facility, or LNG facility." *Id*. at 31684 (text of proposed 49 C.F.R. § 191.22(b)(2)). The corresponding text in the preamble provides that an operator must report "[a] change in the operating entity responsible for managing or administering a safety program (such as an Integrity Management **or Corrosion Protection Program**) covering an existing pipeline, pipeline segment or facility." *Id*. at 31678 (emphasis added). There is no current regulatory requirement to specify a responsible individual or entity for corrosion protection programs, and mentioning it in the regulatory preamble implies this requirement (and perhaps others) either currently exists or is being imposed, without public notice or comment, through these reporting requirements. The unfortunate, parenthetical reference to corrosion protection programs was likely inadvertent; still, INGAA urges PHMSA to clarify that the proposed notification requirements for the registry were not intended to impose, and in fact do not impose, any new substantive requirements concerning the operation of existing safety programs.

17 18 C.F.R. §§ 157.201-.218.

18 18 C.F.R. §§ 157.208(a).

19 *Natural Gas Pipelines; Project Cost and Annual Limits*, 74 Fed. Reg. 6539.

20 18 C.F.R. §§ 157.208(e)(1) (The report must provide a "description of the facilities installed . . . , including a description of the length and size of pipelines, compressor horsepower, metering facilities, taps, valves, and any other facilities constructed.").

21 18 C.F.R. §§ 157.208(e)(2) (The report must provide the "specific purpose, location, and beginning and completion date of construction of the facilities installed, the date service commenced, and, if applicable, a statement indicating the extent to which the facilities were jointly constructed.").

22 18 C.F.R. § 2.55(b)(4).

Projects that are too large to qualify for blanket certification and that do not qualify as facility replacements go forward under project-specific FERC certificates. When construction begins on one of these projects, the pipeline must notify FERC within 10 days. The pipeline must also notify FERC within 10 days once construction is completed and placed in service.[23] Similar 10-day notices apply to acquisitions that are not covered by blanket certification.[24] While not codified in regulations, FERC imposes the reporting requirements on LNG terminals through project-specific certification orders.

Reporting that has proven itself adequate for FERC should equally suffice for PHMSA. For rehabilitations, replacements, modifications, upgrades, uprates, updates and construction, PHMSA regulations should provide that when an interstate natural gas pipeline operator or LNG operator provides a notice to FERC under 18 C.F.R. §§ 2.55(b)(4), 157.20(c), 157.20(d) or 157.208(a), or the corresponding provisions of a project-specific certification order, the operator will furnish a copy to PHMSA.

III. The current version of 49 C.F.R. § 192.25 appropriately distinguishes between discovering a condition that may be reportable and determining that the condition should be reported; proposed language blurring that distinction should be rejected.

As currently written, 49 C.F.R. § 192.25 ("Section 192.25") requires operators to report a safety-related condition "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." The language appropriately recognizes that there is a distinction between discovering a condition, which may or may not be reportable, and determining that the condition is subject to reporting under Section 192.25.

In modifying Section 192.25 to institute PHMSA's Safety-Related Condition Report, the Proposed Rule would eliminate the distinction between discovery and determination by requiring operators to file reports "within five working days (not including Saturdays, Sunday, or Federal Holidays) after the day a representative of the operator first **determines or discovers** that the condition exists, but not later than 10 working days after the day a representative of the operator **determines or discovers** the condition."[25] Ironically, the preamble to the Proposed Rule notes the prevailing distinction between discovery and determination,[26] but does not explain why this distinction is being eliminated.

Discovering a condition and determining that the condition should be reported are distinct events, occurring in a distinct sequence, and this distinction is appropriately captured in the current version of Section 192.25. There is no reasonable basis for eliminating this distinction, and none was articulated in the Proposed Rule. The original language in Section 192.25 should be retained, and the proposed change to this language should be rejected.

IV. The deadline for filing offshore pipeline condition reports should track the current version of 49 C.F.R. § 192.612, which permits performance-based inspection intervals, rather than the original version of 49 C.F.R. § 192.612, which required offshore pipelines to be inspected by a date certain.

As currently written, 49 C.F.R. § 192.27 ("Section 192.27") requires operators to report specifically identified information to PHMSA "within 60 days after completion of the inspection of all its underwater pipelines subject to [49 C.F.R.] § 192.612(a)." The Proposed Rule would eliminate the list of

[23] 18 C.F.R. § 157.20(c)(1), (2).

[24] 18 C.F.R. § 157.20(d)(1), (2).

[25] Proposed Rule, 74 Fed. Reg. at 31685.

[26] *Id*. at 31679.

specific information and instead require operators to file a newly-designed Offshore Pipeline Condition Report. INGAA does not object to the report *per se*. In fact, INGAA commends PHMSA on its design of this report as well as the Safety-Related Condition Report, the LNG Annual Report, and the LNG Incident Report. All four of these reports track their corresponding regulations reasonably well. INGAA's issue concerns timing. The proposed regulation retains the requirement from the current version of Section 192.27; that is, the form must be filed "within 60 days after completion of the inspection of all [of an operator's] underwater pipelines subject to [49 C.F.R.] § 192.612(a)."[27] This timing requirement was adopted in 1991, together with a revision to 49 C.F.R. 192.612 ("Section 192.612") that required operators to complete a one-time inspection of all applicable pipelines by November 16, 1992.[28]

In its historical context — specifically, the inspection deadline imposed by Section 192.612 — the Section 192.27 timing requirement made sense. However, Section 192.612 was subsequently amended to allow individual operators to determine "appropriate periodic" inspection intervals for their pipelines.[29] For an operator that utilizes a risk-based approach, this could mean multiple and changing intervals for the pipelines identified in 192.612(a). Moreover, each operator is allowed to choose the criteria it will use to determine its risk-based inspection intervals.

The timing requirement in Section 192.27 should have been changed when Section 192.612 was amended. Instead, the current timing requirement, which would remain unchanged under the Proposed Rule, is interpreted to mean 60 days after inspection has been completed for the last of the inventory of pipelines identified in 49 C.F.R. § 192.612(a). In the current context of risk-based inspection intervals, the reporting deadline under Section 191.27 would be tied to when the pipeline with the greatest risk based interval was inspected. By the time this occurs, years might elapse and some of the identified pipelines may have been inspected more than one time. The data assembled through the offshore pipeline condition reports would have little continuity and would be of little analytical value.

To harmonize Section 192.27 with Section 192.612 as amended, INGAA recommends amending Section 192.27 to require offshore pipeline condition reports to be filed **as soon as practical but not more than 60 days after the operator discovers that its pipeline is exposed underwater pipeline or poses a hazard to navigation**. The triggering event is drawn from 49 C.F.R. § 192.612(c)(1), which requires an operator to notify the National Response Center by telephone within 24 hours if the operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation.

V. The Annual Report form (DOT Form PHMSA 7100.2.1) and accompanying instructions should be modified in several critical respects, and the modified report and instructions should be recirculated for public comment, as PHMSA did for the agency's standardized forms for reporting pipeline incidents and accidents.

Under the Proposed Rule the semi-annual report on performance measures, which natural gas transmission pipeline operators file as part of their Integrity Management Programs, would be merged with these operators' annual reports. To accommodate this merger, the Proposed Rule would make several modifications to the annual report form and accompanying instructions, and this docket is the appropriate forum to comment on the form and instructions as modified.

For ease in presentation, an annotated copy of the proposed annual report form and instructions is attached to these comments as Appendix A, with INGAA's comments provided in the margin. INGAA's suggested revisions are also described below:

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27 *Id*. at 31685.

28 Amdts. 191-9, 192-67 effective January 6, 1992.

29 Amdt. 192-98. PHMSA based its adoption of risk-based inspection intervals on the data generated by the November 1992 inspections.

OVERALL: All pipeline mileage should be reported to the nearest one-tenth of a mile.

PART A – OPERATOR INFORMATION: Eliminate the last set of check boxes appearing in question 8, which generally asks whether there have been corporate or system changes from what was reported the previous year. The apparent reason for this set of check boxes was if none of the boxes were checked the operator would not have to fill out the form. Still, for none of the boxes to be checked there would have to be no new construction, no new installations, no facility modifications and no abandonments. On this basis alone, virtually every operator will check at least one of the boxes. The rare case where none of the boxes would be checked does not warrant the bother that would be imposed on everyone else.

PART C – DELIVERED VOLUME TRANSPORTED IN TRANSMISSION PIPELINES: It is impractical to provide volume-miles since the natural gas transported does not necessarily traverse the whole pipeline system. In addition, the proposed data is of questionable value. Presently we report the amount of volume transported through the systems, and PHMSA collects the length of the system, so this factor could be determined with just the volume being reported by the companies.

PART D – MILES OF STEEL PIPE BY CORROSION PROTECTION: In this part and in several subsequent sections of the form, it is not clear when gathering lines should be included in reported figures. The form and the corresponding instructions should be adjusted based on the new rulemaking on natural gas gathering lines.

PART F – BASELINE INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION: The form and instructions should make it clear that responses to Part F should include only baseline integrity data for the integrity management program and the amount of mileage in over-testing due to that program.

With regard to question 1, the separate collection of information about the types of in-line inspection devices can be confusing and of marginal value. INGAA recommends this portion of Part F be removed.

Question 2, regarding anomalies, should be collapsed into question 1 and limited to anomalies within high consequence areas ("HCAs"). At present, HCAs are the only locations with standardized repair criteria.

For the same reason, question 3, concerning mileage inspected and actions taken based on pressure testing, should be limited to facilities within HCAs.

With regard to question 4, concerning mileage inspected and actions taken based on direct assessment methods, the next to last paragraph of the instructions is phrased in terms of exceeding repair criteria. The proper phasing is meeting the repair criteria.

PART G – REASSESSMENT INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION. This portion of the form should be broken into several identical subparts, one for each reassessment. In addition, the instructions for Part G should mirror the instructions for Part F.

PART N – CERTIFYING SIGNATURE. As proposed, certification would be for the information contained in Parts H and I. It appears that the proper reference should be to Parts F and G.

INGAA and others filed similar sets of detailed comments when PHMSA announced proposed revisions to its standardized forms for reporting pipeline incidents and accidents.[30] PHMSA agreed with many of the suggested changes, and in light of these changes PHMSA issued a second public notice to

[30] *Information Collection Activities*, 73 Fed. Reg. 51697.

provide an opportunity for the public to comment on the proposed forms as revised to reflect the changes suggested in the comments.[31]

Revisions to the accident reporting forms are proceeding under Office of Management and Budget ("OMB") regulations implementing the Paperwork Reduction Act of 1995,[32] while this docket, and its proposed revisions to the annual report, are proceeding under the rulemaking provisions of the Administrative Procedure Act. While recognizing this distinction, INGAA urges PHMSA follow the accident reporting form precedent here. PHMSA should revise the annual report and accompanying instructions per the comments provided above, and then provide public notice of the revised forms with a 30-day comment period. This approach will insulate the resulting annual reports from criticism, including judicial review, based on whether the initial public notice in this docket made the public reasonably aware that the final version of the annual report could turn out as amended by the comments filed by INGAA and others.[33]

CONCLUSION

INGAA appreciates the opportunity to comment and offers its continued assistance in the development of this important proposed rule.

Respectfully submitted,

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31 *Information Collection*, 74 Fed. Reg. 41496.

32 44 U.S.C. § 3507, see generally 5 C.F.R § 1320.8(d) (OMB implementing regulations).

33 The link between this docket and the Paperwork Reduction Act docket addressing the accident reporting forms is not merely procedural. As evidenced by PHMSA's proposal to require electronic reporting, Proposed Rule, 74 Fed. Reg. at 13677-78 (preamble) and 31684 (text of proposed 49 C.F.R. § 191.7), the accident reports and annual reports form an integrated whole. The histories behind the various reports require they be handled in separate dockets, but the substance of the revision effort should be managed as an integrated whole. Integrated management argues for exposing the annual report revisions to a second round of public notice and comment, as was done for the revisions to the accident reports. Moreover, integrated management suggests coordinated implementation of the revisions to both forms, with a single implementation date, preceded by an appropriate test period, which would allow all of these changes to be implemented at the start of a new calendar year.