(156.65 MHz) and channel 16 (156.8 MHz).

(d) *Enforcement period.* The security zone will be enforced from 3 p.m. until 10 p.m. on May 11, 2007; from 9 a.m. to 11 p.m. on May 12, 2007; and from 9 a.m. to 10 p.m. on May 13, 2007.

(e) *Effective period.* This regulation is effective from 3 p.m. on May 11, 2007, to 10 p.m. on May 13, 2007.

Dated: April 6, 2007.

Patrick B. Trapp,

Captain, U.S. Coast Guard, Captain of the Port, Hampton Roads.

[FR Doc. E7–7669 Filed 4–20–07; 8:45 am]

BILLING CODE 4910–15–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2005–22642]

RIN 2137–AE09

Pipeline Safety: Design and Construction Standards To Reduce Internal Corrosion in Gas Transmission Pipelines

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

ACTION: Final rule.

SUMMARY: This final rule requires operators to use design and construction features in new and replaced gas transmission pipelines to reduce the risk of internal corrosion. The design and construction features required by this rule will reduce the risk of internal corrosion and related pipeline failures by reducing the potential for accumulation of liquids and facilitating operation and maintenance practices that address internal corrosion.

DATES: This final rule takes effect May 23, 2007.

FOR FURTHER INFORMATION CONTACT: Barbara Betsock by phone at (202) 366–4361, by fax at (202) 366–4566, or by e-mail at *barbara.betsock@dot.gov.*

SUPPLEMENTARY INFORMATION:

Background

We initiated this rulemaking proceeding in response to a 2003 recommendation of the National Transportation Safety Board (NTSB) and corresponding advice of the Technical Pipeline Safety Standards Committee (TPSSC). The NTSB recommendation arose out of its investigation of the August 19, 2000 gas transmission pipeline explosion near Carlsbad, New Mexico in which 12 people were killed. In its accident investigation report, PAR–03–01, issued February 11, 2003, the NTSB concluded that the immediate cause of the Carlsbad pipeline failure was severe internal corrosion. The NTSB recommended that PHMSA (1) require that new and replaced gas transmission pipelines be designed and constructed with features to mitigate internal corrosion; (2) require operators to ensure that their internal corrosion control programs address water and other contaminants in the corrosion process; and (3) change its Federal inspection to ensure adequate assessments of pipeline operator safety programs. In 2004 and 2005, the NTSB closed as acceptable PHMSA actions to respond to the second and third recommendations. This rulemaking proceeding responds to the first recommendation.

On December 15, 2005, PHMSA published a notice of proposed rulemaking (NPRM) in the **Federal Register** (70 FR 74262) proposing to require operators to use design and construction features to reduce the risk of internal corrosion in transmission pipelines. As we explained in the NPRM, the proposed rule was intended to prevent the risk of internal corrosion by applying knowledge and experience about the causes and prevention of corrosion to design of pipelines. The incorporation of design features to address internal corrosion improves the ability of the operator to prevent internal corrosion and facilitates maintenance activities to control internal corrosion.

The basic requirements of this final rule are similar to those proposed in the NPRM. New and replaced gas transmission pipelines must be configured to reduce the risk that liquids will collect in the line; have effective liquid removal features; and allow use of corrosion monitoring devices in locations with significant potential for internal corrosion. When an operator changes the configuration of a pipeline, the operator must consider and address the impact the changes will have on the risk of internal corrosion in an existing downstream pipeline. This final rule does not supersede or negate the requirement to address internal corrosion during operation and maintenance activities. Designing and building a pipeline in accordance with the final rule will not prevent internal corrosion unless the operator also follows a well-planned maintenance program. For example, incorporating equipment to measure gas quality will not prevent internal corrosion unless it is used and the operator acts on the results.

Advisory Committee Consideration

PHMSA briefed the TPSSC in June 2005 and considered the Committee's advice in developing the NPRM. PHMSA presented the NPRM and regulatory evaluation to the TPSSC for formal consideration at their meeting on June 28, 2006. At that meeting, members expressed concern that the proposed documentation requirements were burdensome. TPSSC members asked for information about whether PHMSA intended to require detailed documentation of every action taken during design and construction; what alternatives commenters suggested; and how the NTSB reached its recommendation. PHMSA provided additional information in the form of a concept paper on the documentation needed for compliance, an expanded summary of comments, and excerpts from the NTSB report on the Carlsbad incident. PHMSA briefed the TPSSC at a meeting on August 26, 2006 and outlined changes we intended to make in response to comments. A few members expressed individual concerns about particular issues. These concerns are addressed in the remainder of this preamble. The TPSSC voted unanimously to support the NPRM as technically feasible, reasonable, cost-effective and practicable, provided the final rule included the changes PHMSA outlined at the meeting. In addition, the TPSSC advised PHMSA to hold discussions in an open forum on enforcement criteria, including protocol development and recordkeeping. The final rule is consistent with the discussion at the TPSSC meeting. In accordance with the TPSSC's advice, PHMSA intends to convene an open forum soon after the final rule is issued.

Comments on the NPRM

PHMSA received public comments on the NPRM from 18 commenters, 13 of them operators of gas transmission pipelines. The Gas Piping Technology Committee, Interstate Natural Gas Association of America, American Gas Association, the Texas Pipeline Association, and the Iowa Utilities Board also commented. Commenters agreed with the basic concept of the proposal—addressing internal corrosion risks during design and construction. Most commenters viewed the documentation requirements of the proposed rule as burdensome. Some expressed confusion about what an operator would have to do to comply. As an example, some questioned whether the proposed rule would require an operator to conduct an engineering analysis to justify variations in elevation due to following the contours of the land. PHMSA has revised the rule text to clarify the final rule and refine the documentation requirements to ensure compliance without excessive burden. We discuss the major comments and how we are addressing them more specifically in the following paragraphs.

Redundancy

Some commenters contend existing regulations in 49 CFR part 192 make this rulemaking redundant and unnecessary. These commenters point to regulations requiring operators to design new pipeline to allow the use of instrumented internal inspection devices (§ 192.150); to check for internal corrosion when pipe is removed (§ 192.475); to maintain continuing surveillance (§ 192.613); and to develop integrity management programs addressing internal corrosion (subpart O). However, none of the regulations cited by commenters squarely addresses the goals of this rulemaking and the NTSB recommendation.

The purpose of § 192.150 is to allow internal inspection to address a variety of pipeline risks. Section 192.150 incidentally aids internal corrosion control because a pipeline designed to allow internal inspection can also accommodate cleaning pigs. Cleaning pigs remove liquids and contaminants from a pipeline as part of corrosion control. In its report on the 2000 Carlsbad incident, the NTSB recognized the value of cleaning pigs and their limitations in addressing the internal corrosion issues in the Carlsbad incident.[1] The NTSB recommended additional regulation to require design features focused on internal corrosion. In addition, unlike this final rule, § 192.150 does not apply to gathering lines.

The regulations requiring an operator to check line pipe removed from a pipeline for signs of internal corrosion (§ 192.475) and to maintain continuing surveillance (§ 192.613) are not design requirements. These regulations are among those operation and maintenance regulations requiring operators to monitor their pipelines and collect and analyze information about safety risks. But these practices usually only enable operators to detect signs of corrosion. The actions recommended by the NTSB and addressed in this final rule reduce the risk that internal corrosion will even initiate by designing and constructing pipelines to reduce that risk in the first place. Requiring operators to design their systems to reduce the risk of internal corrosion neither duplicates nor obviates the need to detect and monitor internal corrosion.

Some commenters said the proposed rule did not take into account the internal corrosion management plans required by the integrity management regulations (subpart O). In fact, we believe that the final rule will complement the existing requirements under subpart O. Subpart O applies only to pipelines in high consequence areas (HCAs). In those areas, it supplements the safety protection provided by the minimum standards. This final rule sets a minimum standard for design and construction applicable to all onshore pipelines, regardless of location. For pipeline in an HCA, compliance with the new standard will facilitate addressing the risk of internal corrosion under an integrity management program. For example, § 192.927(c)(4) requires an operator to continually monitor covered segments where internal corrosion has been identified. A segment constructed in accordance with this final rule will have liquid removal features and allow the use of appropriate monitoring devices.

Exceptions Based on What the Operator Expects To Occur During Operations

Many commenters requested an exception to the design and construction requirements if the operator believes liquids will not pose a problem in the line. Commenters suggested several variations. Some commenters suggested that we establish an exception applicable if the operator confirms liquids will not present an uncontrolled threat (presumably because of planned corrosion control activities). Others suggested requiring design and construction features only where corrosive gas is transported. Others pointed to areas without a history of internal corrosion and suggested that the rule should not apply to pipelines installed in these areas.

PHMSA does not agree with the suggestions of these commenters and, accordingly, is not establishing exceptions to design and construction requirements based on expected operations. An operator needs to include internal corrosion control measures in operation and maintenance programs. Relying on these operation and maintenance programs alone to control internal corrosion misses the safety and economic benefit from good design. Building features to reduce the risk of corrosion into new pipelines costs little and provides additional and fuller protection against internal corrosion. Even where operators do not expect to have liquids enter the pipeline, one commenter noted that an operator cannot rule out upset conditions which can result in the introduction of liquids. These can occur when there is an operational error; tertiary recovery introduces liquids; gas comes from a new or different area of the same field; gas from a different operator joins the gas stream; equipment fails; or other causes. The increased risk of internal corrosion such a situation causes, albeit possibly small, justifies the minimal incremental cost of incorporating the measures required in the final rule. However, in the interest of cost effectiveness, PHMSA agrees with the need to provide operators flexibility to select design and construction options fitting the relative risks that there will be liquids in the pipeline in the future.

Exceptions for Particular Types of Facilities

A few commenters requested that PHMSA carve out exceptions to the final rule for particular types of pipeline facilities. We address these comments in the following paragraphs, by reference to the particular pipeline facilities in issue.

Offshore pipelines. The Interstate Natural Gas Association of America and one large gas transmission operator requested that PHMSA carve out an exception for offshore lines. Among the reasons given were the lower risk to public safety in the offshore environment and the impossibility of engineering out the effects of dips and low spots offshore. PHMSA agrees that offshore lines should be excepted from the final rule.

Although there have been serious gas incidents offshore, these have been caused by outside force damage sufficient to rupture the pipeline, such as an anchor dragging or vessel

[1] From NTSB report PAR 03–01:

The Safety Board concludes that, as a likely result of the partial clogging of the drip upstream of the rupture location, some liquids bypassed the drip, continued through the pipeline, and accumulated and caused corrosion at the eventual rupture site where pipe bending had created a low point in the pipeline.

Periodic use of cleaning pigs can remove water and other liquid and solid contaminants from a pipeline. One of the considerations for the design and construction of a cleaning pig system is to make provisions for effective collection and removal of the accumulated materials from the pipeline after pigging [* * *]

[* * *] The Safety Board therefore concludes that if the accident section of pipeline 1103 had been able to accommodate cleaning pigs, and if cleaning pigs had been used regularly with the resulting liquids and solids thoroughly removed from the pipeline after each pig run, the internal corrosion that developed in this section of pipe would likely have been less severe.

grounding. This sort of damage includes sources of ignition from vessels passing overhead. In contrast, a corrosion leak in an offshore gas pipeline poses less risk to people. Unless corrosion is widespread, a corrosion failure is likely to leak rather than rupture and is not likely to pose a threat to people. It is highly unlikely that a vessel would pass over the underwater pipeline at the moment of rupture and provide both a source of ignition triggering a fire and people to be killed or injured. Between 2000 and 2005, there were more than twice as many internal corrosion incidents offshore as onshore, but less damage, even though damage includes the cost of lost gas and repair to the underwater pipeline. There have been no injuries or fatalities.[2]

Finally, as noted by the commenters, there are more limited design and construction options available for offshore pipelines. Pipelines commonly follow the contours of the seabed with its natural low points. Installing and operating liquid removal equipment is not possible at low points in deep water. Some new pipelines are being installed in water more than one mile deep, complicating the under water pipeline design process. Control of liquids in the gas stream is already a critical factor in deep water pipeline construction and operation.

Moreover, adopting this exception will not leave offshore pipelines unprotected or allow an operator to ignore the risk of internal corrosion. Existing regulations in subparts I and L require operators of offshore pipelines to address internal corrosion during operation and maintenance.

Gathering lines. The only regulated gas gathering lines are those in populated areas, where the risk of injury or property damage in the event of failure is greatest. By their very nature, gathering lines regularly transport gas containing liquids—a combination known to cause corrosion over time. Approximately a third of onshore incidents caused by internal corrosion involve gathering lines.[3] None of the commenters challenged these basic facts. PHMSA does not except gathering lines from this final rule.

At least one commenter suggested that gathering lines were not within the scope of the NPRM in this rulemaking. That is not the case. When PHMSA issued the NPRM in December 2005, gas gathering lines in non-rural areas were subject to the same regulations applicable to transmission pipelines (49 CFR 192.9 (2005)). The only exceptions were the requirement that new pipelines accommodate internal inspection devices (§ 192.150) and integrity management regulations (subpart O). PHMSA published a Supplemental Notice of Proposed Rulemaking (SNPRM) proposing changes to regulation of gathering lines on October 3, 2005 (70 FR 57536). The SNPRM on gathering lines proposed to continue to subject gathering lines to most regulations applicable to transmission pipelines, including both corrosion control and design and construction requirements. The final rule on gathering lines continued to subject gathering lines to corrosion control and design and construction requirements such as this final rule (71 FR 13289; March 15, 2006).

Compressor stations. PHMSA is not persuaded that the final rule should except compressor stations. The commenter suggesting an exception did not offer a reason, and we cannot discern one. Compressors do not operate well when liquids are present in the gas flow. Actions to remove liquid before it enters the compressor may result in liquid accumulation in the compressor station piping. About forty percent of the damage caused by internal corrosion onshore incidents between 2000 and 2005 was due to incidents at compressor stations. People work in compressor stations. They also live near compressor stations, particularly in suburban locations in which there has been significant development since the transmission pipelines were constructed.

Placement Within 49 CFR Part 192

Several commenters suggest subpart I—Requirements for Corrosion Control—is the wrong place for a rule addressing internal corrosion control in design and construction. Commenters cite two reasons for their position. First, the regulations in subpart I primarily address operation and maintenance requirements. These requirements apply to pipelines existing when the regulations are issued. Design and construction requirements, such as those in the final rule, apply only to new and replaced pipelines. The commenters suggest PHMSA place these requirements applicable only to new and replaced pipelines in one of the subparts of 49 CFR part 192 which contain no requirements applicable to existing pipelines. Second, some commenters suggest that operators designing and constructing pipelines might overlook design and construction requirements placed in subpart I. Commenters who addressed the issue were not uniform in their suggestions for alternate placement within Part 192. They suggest placement in subpart C—Pipe Design, subpart D—Design of Pipeline Components, or subpart G—General Construction Requirements for Transmission Lines and Mains.

Some regulations in subpart I already include design and construction requirements, such as requirements for pipe coating. PHMSA believes consolidating corrosion control requirements strengthens the planning aspects of this regulation. To address commenters' concerns, PHMSA has reworded the final rule to be consistent with other design and construction requirements in the regulations. We have also added an applicability date to the final rule clearly indicating the non-retroactive effect of the design and construction requirements. Finally, the final rule cross references subpart I in subpart D to alert those designing pipelines of the need to consult corrosion control requirements.

Recordkeeping

Many commenters and the TPSSC expressed concern about the recordkeeping provision proposed in the NPRM, contending it would be costly, difficult to adhere to, and burdensome. PHMSA agrees. Operators normally maintain as-built drawings and other construction records. These records may already contain adequate explanation of variances. If not, some additional explanation will be necessary. We have modified the final rule to require maintenance of records demonstrating compliance.

Changes Affecting Downstream Pipeline

Few commenters discussed the proposal to require an operator to address the effect changes to an existing pipeline would have on the risk of internal corrosion in the downstream portions of the pipeline. The Texas Pipeline Association noted that the proposal matched what prudent operators already do and that the proposed standard was appropriate. Another commenter noted the proposed language might be too restrictive because it would require an operator to use equipment to address the effects. One member of the TPSSC noted that the proposal would apply to any change to the pipeline and suggested clarifying the regulation to apply only to changes affecting configuration. We have made changes to the final rule to limit applicability to changes that have the potential for affecting downstream risk. The final rule allows operator flexibility in addressing the risks.

[2] The only fire was almost instantaneously extinguished by the water.

[3] Based on data reported for incidents occurring between 2000 and 2005.

Changes Due To Uprating

Existing pipeline safety regulations (§ 192.555 and § 192.557) allow an operator to increase maximum allowable operating pressure of a gas pipeline through a process called uprating. Uprating results in operation at an increased hoop stress. A pipeline operating at a hoop stress of 20 percent or more of the specified minimum yield strength is considered a transmission pipeline by definition regardless of its function (§ 192.3). Thus, uprating a distribution line may result in its classification as a transmission line. A member of the TPSSC asked whether such a change would result in the line being considered a new transmission line subject to the design and construction requirements of this final rule. The answer is no. The uprated line is not newly constructed. However, to the extent an operator makes replacements in the line in connection with uprating to meet the requirements of § 192.555(b)(2) or § 192.557(b)(3), the replacements must be designed and constructed in accordance with this final rule. In addition, the operator would have to consider the effect of the replacement on internal corrosion risk to the downstream portion of the pipeline.

Terminology

The proposed rule allows an operator to deviate from specific aspects of design and construction if the operator can demonstrate that compliance is ''impracticable'' or ''unnecessary.'' Some commenters said that the terms are too subjective and will result in disputes over the appropriateness of an operator's actions. They suggest clarification through examples. We do not agree that further clarification is required at this time. The terms ''impracticable'' and ''unnecessary'' are used elsewhere in regulation. As long as an operator makes a reasonable effort to address internal corrosion in design and construction, the potential for disagreement is slight. At the request of the TPSSC, PHMSA intends to conduct a public workshop on implementation of this regulation. Part of the workshop could be devoted to developing examples of situations in which regulators and industry agree that compliance with the final rule would be presumptively impracticable or unnecessary.

The Final Rule

The final rule adds a new subsection to § 192.143 in Subpart D—Design of Pipeline Components. The new subsection cross-references the design and installation requirements specifically addressing corrosion control in Subpart I—Requirements for Corrosion Control.

The final rule also adds a new section to subpart I. The new section, § 192.476, requires an operator to address internal corrosion risk when designing and constructing a new gas transmission line or when replacing line pipe or components in a transmission line.

Paragraph (a) addresses design and construction. It imposes a general performance requirement—that the design and construction of new and replaced pipelines include features to reduce the risk of internal corrosion. More specifically, the rule identifies three categories of corrosion control features that an operator must provide for unless doing so is impracticable or unnecessary: (1) Configuration to reduce the risk that liquids will collect in the line (paragraph (a)(1)); (2) effective liquid removal features (paragraph (a)(2)); and (3) ability to use corrosion monitoring devices in locations with significant potential for internal corrosion (paragraph (a)(3)).

There are many design features that an operator can incorporate to address the requirements of paragraph (a). These include the following:

- An operator can minimize dead ends and low areas;
- An operator can minimize aerial crossings, since these can result in variation of temperature;
- An operator can design for turbulent flow, in which the velocity at a given point varies erratically in magnitude and direction, to decrease the chance of liquids separating from the flow and accumulating;
- An operator can design a pipeline to minimize entry of water and corrosive gases at receipt locations;
- When corrosive gas is expected, an operator can provide slam valves to isolate systems;
- An operator can apply coatings to interior walls to inhibit internal corrosion;
- An operator can identify critical low spots and instrument the pipeline to monitor relevant operating conditions (temperature, pressure, velocity, dew point);
- An operator can evaluate seasonal nature of delivery and capacity patterns and design to avoid no-or low-flow conditions;
- An operator can include equipment to evaluate gas characteristics; and
- An operator can include equipment to allow sampling at key areas, such as pig traps, isolated sections with no flow, dead ends, and river and road crossings.

Further, design should allow the use of cleaning pigs.[4]

Paragraph (b) provides exceptions to applicability. The design and construction requirements do not apply to pipeline installed or replacements made before the effective date of the regulation. They also do not apply to offshore pipelines.

Paragraph (c) requires an operator to consider and address the impact of changes in the physical features of a pipeline on internal corrosion risks of an existing downstream pipeline. This will ensure that changes in configuration made after a pipeline begins operation do not inadvertently increase the risk of internal corrosion. An operator who finds an increased risk due to changes upstream might need to install liquid removal equipment. Alternatively, after analysis, an operator may decide operation and maintenance measures would adequately address the impact. In its investigation of the Carlsbad accident, the NTSB noted the impact of the addition of a pig receiver many years after original construction.[5] This change in configuration allowed the liquids from pigging which were not caught in the receiver to flow downstream supposedly to be caught in the drip installed at the time of original construction to capture liquids before the low points near the river. The NTSB report notes that the pig receiver was added without also installing a separate storage leg or tank to collect the liquids from pigging. The NTSB also notes that partial clogging of the original drip, a maintenance issue, allowed liquids to bypass the drip and collect at the eventual rupture site.

Paragraph (d) requires an operator to maintain records demonstrating compliance. Written procedures supported by as-built drawings and other construction records ordinarily will satisfy this requirement. However, these records must adequately show why an action described in paragraph (a)(1), (a)(2), or (a)(3) is impracticable or unnecessary. For example, an operator might have a written design allowing pipe to be laid following the contour of the land. To avoid accumulation of liquid in the low spots, the design procedure might call for incorporating

[4] Section 192.150 requires an operator to design most new and replaced transmission pipeline to allow the use of instrumented internal inspection devices. The exceptions to § 192.150 include certain lower risk gathering lines and lines too small in diameter to accommodate instrumented internal inspection devices. Although neither § 192.150 nor this final rule expressly requires designing to allow the use of cleaning pigs, it is much easier to accommodate cleaning pigs than instrumented internal inspection devices.

[5] NTSB Report PAR 03–01, pages 41–42.

design features to maintain gas velocity or to remove liquids. The actual construction records or as-built drawings would show what the operator actually did. Another example might be a construction record showing the use of a filter or separator at the gate station of a distribution pipeline. Regardless of the choices in recordkeeping an operator makes, the records must show circumstances justifying variance based on impracticability or lack of necessity. For example, if an operator does not provide features for effective liquid removal at low spots, the records must show why it is not necessary to do so.

Regulatory Analyses and Notices

Privacy Act Statement

Anyone can search the electronic form of all comments received in response to any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). The Department of Transportation's complete Privacy Act Statement is published in the **Federal Register** on April 11, 2000 (65 FR 19477), and on the Web at *http://dms.dot.gov.*

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 subject to review by the Office of Management and Budget. This final rule is not significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034).

Commenters pointed to discrepancies in the incident data used for the regulatory evaluation. Those discrepancies have been corrected in the regulatory evaluation for this final rule. One member of the TPSSC questioned whether the analysis included consideration of uncertainties. We have considered the comment and decided that our analysis adequately handles uncertainty in benefits and costs.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities. This final rule would affect operators of gas transmission pipelines and onshore gas gathering pipelines. The number of small entities operating gas transmission pipelines is not substantial and the cost of compliance with the final rule is small. Therefore, I certify, under 5 U.S.C. 605, that this rulemaking will not have a significant impact on a substantial number of small entities.

Executive Order 13175

PHMSA has analyzed this final rule according to Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because the final rule will not significantly or uniquely affect the communities of the Indian tribal governments nor impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act

This final rule affects information collection that the Office of Management and Budget has approved under Control Number 2137–0049 (recordkeeping under 49 CFR part 192). Operators of gas transmission pipelines must keep records to show the adequacy of corrosion control measures. In addition, they must keep construction records and make them available to individuals operating and maintaining the pipeline. The final rule may require some added effort to document decisions about internal corrosion made during design and construction. Because of existing recordkeeping needs and prudent business practice, PHMSA estimates the added burden hours will be nominal.

Unfunded Mandates Reform Act of 1995

This final rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more 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 rulemaking.

National Environmental Policy Act

PHMSA has analyzed the final rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the final rule requires limited physical change or other work that would disturb pipeline rights-of-way, PHMSA has determined the final rule is unlikely to affect the quality of the human environment significantly. An environmental assessment document is available for review in the docket.

Executive Order 13132

PHMSA has analyzed the 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. The final rule does not impose substantial direct compliance costs on State and local governments. Federal pipeline safety law prohibits State safety regulation of interstate pipelines. This regulation would not preempt state law for intrastate pipelines. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211

Transporting gas impacts the nation's available energy supply. However, this final rule is not a ''significant energy action'' under Executive Order 13211. It also is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, the Administrator of the Office of Information and Regulatory Affairs has not identified this final rule as a significant energy action.

List of Subjects in 49 CFR Part 192

Design and construction, Internal corrosion, Pipeline safety.

■ For the reasons provided in the preamble, PHMSA amends 49 CFR part 192 as follows:

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

■ 1. 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.

■ 2. Amend § 192.143 by designating existing text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 192.143 General requirements.

* * * * *

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

■ 3. Add § 192.476 to read as follows:

§ 192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

Issued in Washington, DC on April 16, 2007.

Thomas J. Barrett,

Administrator.

[FR Doc. E7–7701 Filed 4–20–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 070213033–7033–01; I.D. 041807B]

Fisheries of the Exclusive Economic Zone Off Alaska; Yellowfin Sole by Vessels Using Trawl Gear in the Bering Sea and Aleutian Islands Management Area

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; closure.

SUMMARY: NMFS is closing directed fishing for yellowfin sole by vessels using trawl gear in the Bering Sea and Aleutian Islands management area (BSAI). This action is necessary to prevent exceeding the second seasonal allowance of the 2007 halibut bycatch allowance specified for the trawl yellowfin sole fishery category in the BSAI.

DATES: Effective 1200 hrs, Alaska local time (A.l.t.), April 19, 2007, through 1200 hrs, A.l.t., May 21, 2007.

FOR FURTHER INFORMATION CONTACT: Jennifer Hogan, 907–586–7228.

SUPPLEMENTARY INFORMATION: NMFS manages the groundfish fishery in the BSAI according to the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson-Stevens Fishery Conservation and Management Act. Regulations governing fishing by U.S. vessels in accordance with the FMP appear at subpart H of 50 CFR part 600 and 50 CFR part 679.

The second seasonal allowance of the 2007 halibut bycatch allowance specified for the trawl yellowfin sole fishery category in the BSAI is 195 metric tons as established by the 2007 and 2008 final harvest specifications for groundfish in the BSAI (72 FR 9451, March 2, 2007).

In accordance with § 679.21(e)(7)(v), the Administrator, Alaska Region, NMFS, has determined that the second seasonal allowance of the 2007 halibut bycatch allowance specified for the trawl yellowfin sole fishery category in the BSAI has been caught. Consequently, NMFS is closing directed fishing for yellowfin sole by vessels using trawl gear in the BSAI.

After the effective date of this closure the maximum retainable amounts at § 679.20(e) and (f) apply at any time during a trip.

Classification

This action responds to the best available information recently obtained from the fishery. The Assistant Administrator for Fisheries, NOAA (AA), finds good cause to waive the requirement to provide prior notice and opportunity for public comment pursuant to the authority set forth at 5 U.S.C. 553(b)(B) as such requirement is impracticable and contrary to the public interest. This requirement is impracticable and contrary to the public interest as it would prevent NMFS from responding to the most recent fisheries data in a timely fashion and would delay the closure of directed fishing for yellowfin sole by vessels using trawl gear in the BSAI. NMFS was unable to publish a notice providing time for public comment because the most recent, relevant data only became available as of April 17, 2007.

The AA also finds good cause to waive the 30-day delay in the effective date of this action under 5 U.S.C. 553(d)(3). This finding is based upon the reasons provided above for waiver of prior notice and opportunity for public comment.

This action is required by § 679.21 and is exempt from review under Executive Order 12866.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: April 18, 2007.

James P. Burgess

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

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