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Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines; Final Rule

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA–97–2762; Amdt. 195–73]

RIN 2137–AD24

Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Final rule.

SUMMARY: This Final Rule makes changes in some of the corrosion control standards for hazardous liquid and carbon dioxide pipelines. The changes are based on our review of the adequacy of the present standards compared to similar standards for gas pipelines and acceptable safety practices. The changes are intended to improve the clarity and effectiveness of the present standards, and reduce the potential for pipeline accidents due to corrosion.

DATES: This Final Rule takes effect January 28, 2002. The incorporation by reference of the publication listed in the rule is approved by the Director of the Federal Register January 28, 2002.

Compliance dates: Under § 195.563(c), operators of certain effectively coated buried piping in breakout tank areas or pump stations are not required to cathodically protect that piping until December 29, 2003. Under § 195.567(a), operators of cathodically protected pipelines or pipeline segments that lack test leads for external corrosion control are not required to install test leads until December 29, 2004. Under § 195.573(a)(2), operators are not required to determine the circumstances in which a close-interval survey or comparable technology is practicable and necessary until December 29, 2003. Under § 195.573(b), operators of unprotected pipe are not required to reevaluate the need for corrosion control on the pipe at least every 3 years until December 29, 2003.

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SUPPLEMENTARY INFORMATION:

Background

Corrosion causes a significant proportion of hazardous liquid pipelines accidents. Based on this finding, we reviewed the corrosion control standards in 49 CFR part 195 to determine if the standards need to be made clearer, more effective, or consistent with acceptable safety practices. We believe that improving the standards will have the potential to reduce the number of accidents caused by corrosion.

The review began September 8, 1997, when we held a public meeting in Oak Brook, Illinois to discuss how part 195 corrosion control standards and the corrosion control standards for gas pipelines in 49 CFR part 192 might be improved (62 FR 44436; Aug. 21, 1997). We held the public meeting in conjunction with meetings of National Association of Corrosion Engineers International (NACE), a professional technical society dedicated to corrosion control. Participants agreed, universally, that part 192 and part 195 corrosion control standards are largely sufficient, and although some changes may be needed, the standards should remain generally unchanged.

Based on this conclusion, we began to consider whether the more comprehensive part 192 gas standards, possibly with some changes, would be appropriate for part 195's hazardous liquid and carbon dioxide pipelines. We met then, from time to time, with representatives of NACE, the pipeline industry, and state pipeline safety agencies for technical input. At these meetings, we also examined whether the part 192 standards need to be more effective or clearer. The meetings raised various concerns about the effectiveness and clarity of some of the part 192 corrosion control standards and the suitability of applying those standards to hazardous liquid and carbon dioxide pipelines. We also took into account that the National Association of Pipeline Safety Representatives, the Gas Piping Technology Committee, and the National Transportation Safety Board had at various times recommended changes to part 192 and part 195 corrosion control standards. So, to gather public comment on our concerns and the changes these organizations recommended, we held another public meeting on April 28, 1999, in San Antonio, Texas, and invited the public to submit written comments. The comment period remained open until June 30, 1999 (64 FR 16885; April 7, 1999).

Notice of Proposed Rulemaking

Sixty-two persons filed written comments in response to the San Antonio meeting notice. We then summarized these comments in a notice of proposed rulemaking (NPRM) published last year (65 FR 76968; Dec. 8, 2000). The NPRM proposed to add to part 195 a new subpart H called Corrosion Control. Subpart H would prescribe corrosion control standards for all new and existing steel pipelines to which part 195 applies. At this time, we also decided to address the concerns, recommendations, and comments that pertain primarily to the corrosion control standards in part 192 in a separate notice of proposed rulemaking on gas pipelines.

Although there was little support in the record for allowing NACE Standard RP0169–96, ''Control of External Corrosion on Underground or Submerged Metallic Piping Systems,'' to serve as an alternative to standards proposed in subpart H, we specifically requested further comment on this issue due to NACE's standing in the field of corrosion. Unfortunately, no one commenting on the NPRM responded to that request, perhaps because of earlier discussions of the issue in Oak Brook and San Antonio. While NACE urged us to reference the entire NACE Standard, not just section 6 as we proposed, NACE did not assert that the NACE Standard could serve as an acceptable alternative to proposed subpart H.

The NPRM discussed each of the standards proposed for inclusion in subpart H. Many of these standards are identical to present corrosion control requirements in part 195, and many of the standards are substantially like the present requirements in part 192. Proposed subpart H also includes standards that, while based on present part 192 requirements, include changes which we think are beneficial improvements.

Discussion of Comments

We received comments from the following entities in response to the NPRM: Alberta Energy Company (AEC), City of Dallas Water Utilities, Enron Transportation Services Company (Enron), Environmental Defense, Equilon Pipeline Company (Equilon), L.A. ''Roy'' Bash, NACE, Phillips Pipe Line Company (Phillips), State of Iowa Utilities Board (Iowa), State of Washington Utilities and Transportation Commission (WUTC), and Tosco Corporation (Tosco). Most commenters supported the rulemaking, and all but the City of Dallas recommended changes to some of the proposed standards.

The City of Dallas related its experience with a major pipeline spill caused partly by corrosion. Gasoline containing MTBE, a fuel oxygenate which effects the taste and odor of water, entered a lake resulting in a water supply crisis. The City stated that it is critical for DOT to adopt rules to require all pipelines, especially those transporting gasoline with MTBE near a municipal water resource, to be regularly monitored for corrosion, cracks, and leaks; and that any deficiencies found, be timely repaired.

This rulemaking will accomplish what the City of Dallas is seeking with respect to corrosion. In particular, §§ 195.573, 195.579, and 195.583 will require operators to monitor pipelines regularly for corrosion and correct any deficiencies found in corrosion control. Additionally, new § 195.585 specifies corrective action for any harmful corrosion found. The timeliness of correcting corrosion control deficiencies and harmful corrosion is covered by existing §§ 195.401(b) and 195.452(h).

The requirement for operators to patrol their pipelines regularly for signs of failures is longstanding (§ 195.412(a)). However, we recently broadened requirements by publishing standards on integrity management which will require pipelines in or near high-consequence areas, such as drinking water sources, to be internally inspected or pressure tested at regular intervals for corrosion, cracks, and other defects (65 FR 75377; Dec. 1, 2000). These new standards currently apply to operators with 500 or more miles of hazardous liquid pipelines, and we have proposed similar standards for the remaining hazardous liquid operators subject to part 195 (66 FR 15821; Mar. 21, 2001).

The following material, which is organized by sections of final subpart H, summarizes comments on the NPRM. In addition, the material explains how we treated the comments and other considerations in developing final subpart H. If a subsection is not mentioned, no significant comments were received on the corresponding proposed rule and we are adopting the proposed rule as final.

Section 195.551. This informational section provides the content of subpart H. Subpart H contains minimum requirements for protecting steel pipelines against corrosion.

In commenting on proposed § 195.551, Tosco suggested we replace the term ''steel'' with ''metallic'' so subpart H would apply to pipelines made of any metal. Indeed, our corrosion control standards for gas pipelines apply to any metallic pipeline (49 CFR 192.451(a)). However, in contrast to gas pipelines, hazardous liquid and carbon dioxide pipelines are almost exclusively made of steel. For this reason, many of the existing standards in part 195, including corrosion control standards, apply only to steel pipelines. Our review of the corrosion control standards did not disclose a need to expand their coverage to include pipelines made of metals other than steel. In commenting on the NPRM, no one, including Tosco, presented information to explain why the coverage should be expanded. Nevertheless, operators are required to provide us an opportunity to review the safety of any pipeline that is to be constructed with a material other than steel (§ 195.8). In the case of a metallic pipeline made from a material other than steel, such as aluminum, our review would include the operator's plan for corrosion control.

Section 195.553. This new section was not in the NPRM. It provides definitions of terms used in subpart H. The definitions of ''active corrosion,'' ''electrical survey,'' and ''pipeline environment,'' proposed in § 195.569(c), drew no adverse comment. Additionally, final § 195.553 establishes definitions of ''buried'' and ''you.'' The definition of ''buried'' reflects the common corrosion control practice of treating any portion of pipe in contact with the soil as if that portion were buried. The term ''you'' has the same meaning as ''operator.''

Section 195.555. This section, based on proposed § 195.553, keeps in effect the existing qualification standards in § 195.403(c) for corrosion control supervisors. Under § 195.403(c), each operator must require and verify that its supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under § 195.402 for which they are responsible, to insure compliance.

While Tosco and WUTC supported the proposed rule, Phillips objected to it. Phillips believed that part 195 should include qualifications for supervisors of all operation and maintenance activities, not just corrosion control. In the negotiated rulemaking on qualification of pipeline personnel (64 FR 46866; Aug. 27, 1999), we removed the requirements in § 195.403(c) concerning qualifications of supervisors of operations and maintenance activities, effective October 28, 2002. We did so based on the requirement under subpart G of part 195, that on this date, individuals performing regulated operation and maintenance activities must be fully qualified, thus lessening the need to regulate the qualifications of their supervisors. After revising § 195.403(c), our more specific review of the corrosion control standards called attention to the special role that supervisors play in carrying out corrosion control activities. As we explained in the NPRM, individuals qualified to do such activities as taking electrical readings, usually hand the data collected over to supervisors who make critical decisions about corrosion control adequacy and the need for corrective action. None of the commenters, including Phillips, argued that corrosion control supervisors do not need to have the qualifications required by existing § 195.403(c). So given the special role of corrosion control supervisors and the apparent acceptability of the existing supervisor qualification requirements, we continue to believe those requirements should remain in effect after October 28, 2002. This decision does not affect the expiration on October 28, 2002, of qualification requirements for supervisors of other operation and maintenance activities.

Equilon and NACE believed qualifications for supervisors should be no less rigorous than stated in paragraph 1.3 of NACE Standard RP0169–96. These NACE provisions address the need for corrosion control supervisors to have a minimum level of technical competency.[1] In our corrosion control review, we considered this NACE provision as well as 49 CFR 192.453, which provides that gas pipeline corrosion control procedures must be carried out by or under the direction of a person qualified in corrosion control methods. Also, in the San Antonio meeting notice, we asked if more specific standards are needed for individuals who direct corrosion control procedures. Everybody who responded opposed changing § 192.453, and most responders also opposed establishing specific technical qualifications like those in NACE Standard RP0169–96. We expect that individuals who qualify as a supervisor under proposed § 195.553, will have appropriate technical training or experience in corrosion control. Given that neither our review, nor comments on the NPRM disclosed anything in the pipeline industry's safety record to demonstrate the need for more specific technical qualifications, we did not adopt the Equilon and NACE comment.

Sections 195.557, 195.559, and 195.561. These three standards on

[1] Paragraph 1.3 reads:

The provisions of this standard shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, required by education and related practical experience, are qualified to engage in the practice of corrosion control on buried or submerged metallic piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists or cathodic protection specialists by NACE if their professional activities include suitable experience in external corrosion control of buried or submerged metallic piping systems.

external coating are based on proposed § 195.555 and 195.557. Collectively, the standards require buried or submerged pipelines to have external coating with particular attributes, and require operators to inspect pipe coating and repair any damage. As stated in proposed § 195.555, the standards are limited to pipelines constructed, relocated, replaced, or otherwise changed after certain effective dates in § 195.401(c); and limited to certain converted pipelines. In final § 195.557, we have clarified that aboveground breakout tank bottoms need not be coated. We determined that such a requirement is impractical and not a customary corrosion control practice.

In the NPRM, we proposed in § 195.555 to limit the applicability of proposed §§ 195.557 (external coating), 195.559 (cathodic protection), and 195.561 (test leads) to pipelines constructed, replaced, relocated, or otherwise changed after the applicable effective date. We based proposed § 195.555, for the most part, on existing § 195.200, titled Scope, which similarly limits the applicability of corresponding existing §§ 195.238, 195.242, and 195.244. However, we inadvertently omitted from § 195.555 the pipe movement exception included in § 195.200. In this Final Rule, the substance of proposed § 195.555 regarding external coating and cathodic protection is in § 195.557(a), which does include the omitted exception for pipe movement. We addressed the proposed limit on test leads differently, as discussed below under the heading, section 195.567.

Tosco believes it would be helpful to include in subpart H the past effective dates cross-referenced in proposed § 195.555. Tosco believes the dates are not widely known. We did not adopt this comment because the dates are already stated in § 195.401(c) for purposes of indicating the applicability of standards in addition to corrosion control standards, and we do not want to create an unnecessary redundancy in part 195.

Final § 195.557 specifies which pipelines must have external coating. Rather than cross-referencing § 195.5(b) to indicate which converted pipelines must have coating, we transferred to final § 195.557 the coating aspect of § 195.5(b). We transferred the cathodic protection aspect to final § 195.563(b); and the test lead aspect is covered by § 195.567.

Equilon and NACE suggested we establish an additional standard to minimize damage to coating when operators install pipe by boring, driving, directional drilling, or any similar method. Final § 195.559(d) requires external coating to have enough strength to resist damage due to handling and soil stress. We believe this standard is broad enough to cover the potential pipe installation problems raised by these commenters.

Phillips advised against requiring the installation of coating on older existing bare or ineffectively coated pipelines. We believe Phillips may be referencing existing hazardous liquid pipelines constructed before the applicable effective dates stated in § 195.401(c). These pipelines are not subsequently replaced, relocated, or otherwise changed. Final § 195.557 does not require these older pipelines to be coated.

Tosco suggested that § 195.557 should include the dates for which pipelines must have external coating. The final rule accomplishes this objective by cross-referencing § 195.401(c). Restating the dates listed in § 195.401(c) would be unnecessarily redundant since the dates are in § 195.401(c) for purposes other than corrosion control.

Section 195.563. Final § 195.563 combines cathodic protection requirements proposed in §§ 195.555, 195.559, and 195.563. It also cross-references final § 195.573(b), which requires cathodic protection of unprotected pipe found to have active corrosion. As a result, all pipelines that must have cathodic protection under subpart H are identified in a single section.

Final § 195.563(a), which is based on proposed §§ 195.559(a) and (b), requires cathodic protection on each pipeline that must have an external coating under § 195.557(a). The cross-reference to § 195.557(a) limits the cathodic protection requirement to those pipelines constructed, relocated, replaced, or otherwise changed after certain dates, as proposed under § 195.555. Section 195.563(a) does not contain the second sentence of proposed § 195.559(a) which would require operators to have a test procedure to determine whether adequate cathodic protection was achieved. We now believe this sentence is redundant due to the routine monitoring conducted to determine the adequacy of cathodic protection, required by final § 195.573(a). Also, amended § 195.402(c)(3) requires operators to have procedures to carry out § 195.573(a). Although proposed § 195.559(b) only referred to completion of construction as the beginning of the period during which cathodic protection must be installed, final § 195.563(a) reflects the broader applicability indicated by proposed § 195.555.

We proposed in § 195.559(a), which was based on existing § 195.242(a), a requirement that operators install cathodic protection systems on all buried or submerged pipelines ''to mitigate corrosion that might result in structural failure.'' Equilon and NACE suggested this proposed rule would be clearer if we replaced ''structural failure'' with ''structural failure or penetration of pipe or tank wall.'' In light of their comment, we believe the phrase, ''to mitigate corrosion that might result in structural failure,'' creates confusion. It could be interpreted to require protection only against severe external corrosion. Moreover, since it is clear that existing § 195.242(a) requires cathodic protection against all external corrosion, the phrase seems superfluous. Therefore, we did not use it in final § 195.563(a).

Equilon and NACE also commented on the § 195.559(b) proposed requirement that a cathodic protection system be installed not later than 1 year after completing construction. They believe cathodic protection should be in effective operation at the end of 1 year, to guard against significant corrosion that could be caused by stray currents or galvanic long-line currents. We believe effective operation is implicit in the existing and proposed standards on installation of cathodic protection. Nevertheless, to avoid confusion on this point, in final § 195.563(a) we replaced ''installed'' with ''in operation.'' This change is consistent with the comparable standard for gas pipelines in § 192.455(a)(2). Under final § 195.571, when the cathodic protection system is placed in operation, it would have to comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169–96. Subsequent electrical tests and other steps required by final § 195.573(a) will assure that adequate protection is maintained.

WUTC raised the concern that under proposed § 195.559(b) corrosion could go uncontrolled on some facilities for up to 2 years. Based on a Washington State administrative rule, WUTC recommended that § 195.559(b) require that facilities be cathodically protected within 90 days after they are buried or submerged. We did not propose to change the currently required time limit (1 year after completing construction) because our review of the corrosion control standards and the comments from the San Antonio meeting did not indicate any need to reduce the installation time limit. After considering

WUTC's comment, we still believe 1 year after construction is acceptable as a generally applicable time limit considering that soil conditions may need time to stabilize in order to support cathodic protection.

Final § 195.563(b) requires cathodic protection on certain converted pipelines. This requirement does not differ substantively from the cathodic protection aspect of the corrosion control requirement of § 195.5(b). Therefore, we are modifying § 195.5(b) to cross-reference the new subpart H standards.

Under final § 195.563(c), which is based on proposed § 195.563, all buried or submerged pipelines, that have an effective external coating must have cathodic protection. This requirement does not apply to breakout tanks. This requirement is substantially the same as existing § 195.414(a), which requires that all effectively coated pipelines must be cathodically protected, except for breakout tank areas and buried pumping station piping.

However, Equilon and NACE each stated it saw no need to except buried piping in breakout tank areas and pumping stations from the requirement to cathodically protect effectively coated pipelines. We agree that the exception seems to lack a sound safety basis. For example, NACE Standard RP0169–96 does not have a similar exception from cathodic protection. Also, we believe it is now common practice in the hazardous liquid pipeline industry to cathodically protect effectively coated buried piping in breakout tank areas and pump stations. So, in view of the Equilon and NACE comments, and our further consideration, we decided to terminate the exception for buried piping in breakout tank areas and pumping stations. Therefore, the final rule keeps the exception in effect only until December 29, 2003. This period will give operators time to install cathodic protection on any effectively coated piping in breakout tank areas and pumping stations where it is not already installed. Also, since no one commented on application of the proposed rule to the bottoms of breakout tanks and there may not be many older breakout tanks that have effectively coated bottoms, the final rule does not change the present exception for breakout tank bottoms.

Initially, we did not propose regulations similar to §§ 195.414(b) and (c), which require cathodic protection in areas of active corrosion found through electrical inspections previously required on bare pipelines, breakout tank areas, and buried pumping station piping. We reasoned that §§ 195.414(b) and (c) are no longer necessary because the inspection deadlines had expired. However, we now recognize that the cathodic protection provisions of §§ 195.414(b) and (c) are continuing requirements, and so we included them in subpart H as final § 195.563(d).

Section 195.565. This section, concerning the installation of cathodic protection on breakout tanks, is the same as proposed § 195.559(c). There were no comments on proposed § 195.559(c).

Section 195.567. In this section concerning test leads, paragraphs (a) and (b) are based on proposed § 195.561 and existing § 195.244. The existing test lead standards in § 195.244 apply to onshore pipelines constructed, replaced, relocated, or otherwise changed after certain past dates; and to onshore converted pipelines if required by § 195.5(b). The NPRM did not propose to vary this application. However, upon further consideration of the importance of test leads in determining the adequacy of cathodic protection, we are applying final § 195.567 to all onshore pipelines that must have cathodic protection under subpart H. This increased coverage will affect pipelines or segments of pipelines that must have cathodic protection under existing §§ 195.414 and 195.416(d) (i.e., effectively coated pipelines and places on bare pipelines, breakout tank areas, and pumping station piping where active corrosion is found through electrical inspection). The increased coverage will also affect converted pipelines that were not substantially in compliance with existing § 195.244 when placed in service, as § 195.5(b) now permits. To ease the burden of compliance on existing cathodically protected pipelines or pipeline segments on which test leads are not now required by existing § 195.244 or § 195.5(b), final § 195.567(a) allows operators 3 years to identify these pipelines or pipeline segments and install test leads as necessary to meet § 195.567(b). On existing unprotected pipelines, any newly identified segment that must have cathodic protection as a result of an electrical survey under final § 195.573(b), must have test leads in time to carry out the annual monitoring test under final § 195.573(a).

Final § 195.567 is consistent with acceptable practices. The practices recommended for test leads in NACE Standard RP0169–96 and in ASME B31.4 are not limited to new, relocated or replaced pipelines. Also, our gas pipeline regulations in 49 CFR 192.469 and 192.471 for test stations and test leads, apply to all gas pipelines that must be cathodically protected under 49 CFR part 192. Moreover, existing § 195.416(a) requires annual testing of each cathodically protected pipeline to determine the adequacy of cathodic protection; and operators normally comply with this requirement by obtaining electrical measurements through test leads. So we believe § 195.567 will have only a minimal impact on hazardous liquid pipeline companies.

Based on existing § 195.244(b)(1), we proposed in § 195.561(b)(1) that operators install test leads with enough looping or slack to prevent the leads from being unduly stressed or broken during backfilling. Equilon and NACE suggested that to assure test lead wires remain effective, we should add the phrase "to remain mechanically secure and electrically conductive." We believe the objective of this phrase is within the purpose of the existing rule, and therefore, added the phrase to final § 195.567(b)(2) for emphasis.

The long term integrity of test leads is also covered by final § 195.567(c). Based on proposed § 195.573, this standard requires maintenance of test leads. There were no comments on the proposed rule, however we edited the final rule for clarity.

Equilon and NACE also commented on testing cathodic protection of offshore pipelines. They contended that test lead readings at platforms or at shore locations may be of little benefit in determining the adequacy of cathodic protection of offshore pipelines. As an alternative to such readings, they suggested we require operators to analyze or inspect each cathodic protection system before the end of its design life. In our experience, test leads for offshore pipelines normally are installed only on platforms or on shore because of the difficulty of accessing leads at underwater locations. For this reason, § 195.567 does not apply to buried or submerged portions of offshore pipelines. Since pipeline corrosion in an offshore environment generally occurs at a uniform rate, we believe readings taken by operators at offshore platforms or on shore are used satisfactorily to determine the adequacy of protection over the entire pipeline. Moreover, this test method is acceptable for offshore gas pipelines under paragraph A862.15 of the ASME B31.8 Code. Because there is no information to support the need to require the use of an alternative testing method, we chose not to take action on the commenters' suggestion.

WUTC commented that because the proposed standard does not prescribe the number or precise location of test leads, government inspectors may disagree with operators over whether test readings are sufficient to determine the adequacy of cathodic protection. To ameliorate this situation, WUTC suggested that we require operators to conduct close-interval electrical surveys every 5 years. Although final § 195.567 does not specify the number or precise location of test leads, it does provide a performance standard for the location of test leads. Under § 195.567(b)(1) test leads must be installed at sufficiently frequent intervals to obtain electrical measurements indicating the adequacy of cathodic protection. Section 4.5 of NACE Standard RP0169–96, which lists many customary test lead locations, may be used as a guide to comply with § 195.567(b)(1). Additionally, the final rule on monitoring external corrosion control, § 195.573, will require operators to use close-interval surveys in some situations and install additional test leads where warranted.

Section 195.569. This section, which is based on proposed § 195.565, provides that whenever an operator learns that any portion of a buried pipeline is exposed, the exposed portion must be examined for external corrosion if the pipe is bare or has deteriorated coating. Further, if external corrosion requiring remedial action is found, the operator must investigate pipe in the vicinity of the exposed portion (by visual examination, indirect method, or both) to determine if there is any additional external corrosion requiring remedial action.

Phillips requested more flexibility in the proposed requirement to look for additional corrosion. Phillips commented that the extent of further investigation should depend on the type of corrosion found and whether the corrosion could be expected to extend beyond the exposed segment. We do not believe there is a clear understanding of the relationship between the type of corrosion and the likelihood of finding similar corrosion in the vicinity of the exposed pipe to justify limits on the requirement for additional investigation. Pipe and soil conditions are generally too variable to make such predictions with accuracy. Therefore, we did not adopt Phillips' comment.

WUTC believed subpart H should include additional requirements for operators to do more to determine the condition of coating than just visually examine it whenever pipelines are exposed. WUTC stated that the standards should require operators to conduct surveys to identify areas with coating defects and take remedial measures such as re-coating the pipeline. Although the final rules do not specifically require pipe coating surveys, operators must conduct electrical tests periodically to determine the adequacy of corrosion control on their buried pipelines. Low cathodic protection potential readings obtained during these tests often are a sign of coating defects. So, in areas with low potential readings, many operators supplement cathodic protection tests with coating surveys to help them identify places where the pipeline must be excavated to look for corrosion cells or to determine where additional cathodic protection must be applied. The need to mandate the use of coating surveys in addition to electrical tests for corrosion, was not evident from our review of the regulations.

Section 195.571. This standard, proposed as § 195.567, incorporates by reference the criteria and other considerations in section 6 of NACE Standard RP0169–96, as standards for the adequacy of cathodic protection.

Environmental Defense and Iowa argued that because cathodic protection criteria are fundamental to safety, the criteria should be stated in part 195 rather than incorporated by reference. Iowa believed that acquiring and maintaining a separate document is arbitrary and unnecessarily burdensome. In considering these comments, we reviewed OMB Circular A119 and the National Technology Transfer and Advancement Act of 1995. Both documents direct Federal agencies to use consensus standards where practical to meet their policy objectives rather than develop government-unique standards. We also reviewed the rules of the **Federal Register** on incorporation by reference. In light of these Federal policies, we think it is appropriate for us to incorporate the NACE criteria and other considerations by reference, as proposed.

Enron, Environmental Defense, and L. A. (Roy) Bash urged us to adopt the criteria in Appendix D of part 192 instead of the NACE criteria. Enron commented that many operators are successfully using Appendix D for hazardous liquid pipelines; and Environmental Defense viewed Appendix D as more specific and therefore more enforceable. Roy Bash submitted technical documentation in support of two Appendix D criteria, 300 mV shift and E-log-I. In the NPRM we discussed our reluctance to propose Appendix D as the new standard for hazardous liquid pipelines because the Appendix D 300 mV shift and E-log-I criteria are not incorporated in the NACE Standard. Furthermore, we explained that under paragraph 6.2.1 of the NACE Standard, operators may use any criteria which they can demonstrate achieves corrosion control comparable to section 6 criteria. Also, operators may continue to use criteria which they have successfully applied to existing pipelines, on these pipelines. While this provision may satisfy Enron, and should satisfy Roy Bash's concern about the continued use of the 300 mV shift and E-log-I criteria, the lack of specificity in paragraph 6.2.1 may be indicative of Environmental Defense's concern. Yet, we do not believe the performance wording of paragraph 6.2.1 alone is sufficient reason not to reference section 6 of the NACE Standard. On the contrary, we generally favor performance standards over specification standards because they encourage operators to develop and apply better alternatives. If however, an operator chooses to use alternative criteria, we will carefully examine the operator's rationale for determination that the criteria met the "comparable to" or "successfully applied" tests of paragraph 6.2.1 of the NACE Standard.

WUTC was concerned that the criteria in section 6 of the NACE Standard would not be mandatory because paragraph 6.1.1 refers to paragraph 1.2, which states that the Standard is a guide; and also refers to paragraph 1.4, which allows deviations from the Standard. Proposed § 195.567 refers solely to the criteria and other consideration provisions of section 6, which are contained in paragraphs 6.2 and 6.3 of the NACE Standard. We did not intend to allow operators to treat section 6 as a guide or to deviate from the criteria and other considerations in section 6. Therefore, the final rule refers to paragraphs 6.2 and 6.3, instead of section 6.

WUTC was also concerned about special conditions, such as elevated temperatures, disbonded coatings, thermal insulating coatings, shielding, bacterial attack, and unusual contaminants in the electrolyte, which may cause cathodic protection to be ineffective. WUTC believed the rules on coating and cathodic protection should address these special conditions. The theory behind final § 195.571 is that if all external surfaces of a pipeline are cathodically protected according to the criteria and other considerations in paragraphs 6.2 and 6.3 of the NACE Standard, external corrosion will be controlled successfully. In practice, if an operator learns though in-line inspection or other means that because of a special condition external corrosion is not being controlled successfully, the operator must take corrective action. The operator could either remedy the condition or adjust the cathodic protection system to assure the adequacy of cathodic protection in the area of the special condition. We believe this requirement is implicit in final § 195.571. Section 195.573(e) also would require corrective action if the condition is detected by monitoring under § 195.573.

In addition, WUTC was concerned that the proposed rules did not specify how long the cathodic protection current may be shut off when measuring polarization decay under the minimum 100 mV criterion. WUTC suggested that the limit be no more than 48 hours, unless a recording chart shows continuing significant decay beyond that time. To satisfy the100 mV criterion by the decay method, operators must determine that a negative polarization voltage shift of at least 100 mV occurs after the immediate voltage shift caused by shutting off the cathodic protection current. Whether this minimum negative voltage shift occurs in minutes or hours after the current is cut off, it is irrelevant to satisfying the criterion. We recognize that the longer the current remains off, the greater the opportunity for the pipeline to corrode. However, in our experience decay tests have not posed a serious problem in this regard to warrant establishing a time limit.

Finally, WUTC opposed use of the net protective current criterion on bare or ineffectively coated hazardous liquid pipelines. WUTC was concerned about the criterion being applied only at predetermined current discharge points identified through leaks, leak history, or electrical surveys, preventing the pipeline from having complete cathodic protection against corrosion leaks. WUTC suggested that if we allow use of the criterion, we limit its use to pipelines constructed before part 195 went into effect. According to part 195's terms, the net protective current criterion applies only to bare or ineffectively coated pipelines. Because all pipelines subject to part 195 construction standards must be effectively coated, the net protective current criterion will mostly be used on older pipelines constructed before those standards took effect. The effective dates for different groups of pipelines are stated in § 195.401(c).

WUTC's primary concern seems to be that we did not propose a requirement that operators fully cathodically protect bare or ineffectively coated pipelines. We did not propose such action for several practical reasons. To cathodically protect these pipelines over their entire surface area without first coating or recoating them would require very high levels of impressed currents. Cathodic protection systems producing such high current levels would be costly to install, maintain, and operate. Also, to coat all bare or ineffectively coated buried pipelines in order to facilitate cathodic protection could be a costly endeavor. We also considered the possibility that raising pipe sections to coat them would likely create unanticipated stresses and disturb pipe foundations, introducing new risk factors not present in the existing pipelines.

Section 195.573. This section is based on proposed § 195.569. It requires operators to monitor the performance of cathodic protection facilities and monitor unprotected pipe for active corrosion.

Final § 195.573(a) enhances proposed § 195.569 with regard to determinations of the adequacy of cathodic protection. We edited § 195.573(a) to clearly state that operators must conduct tests to determine whether cathodic protection complies with § 195.571 and not whether cathodic protection is adequate, as proposed. In addition, we are concerned that proposed § 195.569 does not provide latitude in monitoring separately protected short segments of bare or ineffectively coated pipelines, as does the corresponding rule for monitoring protected gas pipelines (49 CFR 192.465(a)). The gas rule allows monitoring of short protected segments over a 10-year period where annual monitoring is impractical. We considered adding a similar provision to § 195.573(a) but decided that the 10-year period would add more latitude than circumstances warrant on bare or ineffectively coated hazardous liquid pipelines. Many operators now monitor short protected segments of bare or ineffectively coated lines on the same cycle as adjoining unprotected segments. So, rather than use the gas rule provision, we added a provision that allows monitoring at 3-year intervals which is consistent with the monitoring cycle we are adopting for unprotected sections (see discussion of § 195.573(b) below).

We also addressed the problem of how to test pipelines to determine the adequacy of cathodic protection. In complying with existing § 195.416(a), which was the basis of proposed § 195.569, operators generally conducted electrical surveys. This action involves measuring potentials at pre-established test stations, to determine the adequacy of cathodic protection. In practice, however, this method of compliance has not always been sufficient to assure protection of all pipeline surfaces. Corrosion problems often arise in areas between test stations where there may be interference currents, different environmental conditions, damaged coatings, or malfunctioning anodes. So, in order to check on cathodic protection adequacy in greater detail, many operators augment test station data with periodic close-interval electrical surveys or use newer technologies. As WUTC pointed out in its comments, these more detailed surveys also help operators determine if additional test stations are needed to assure the adequacy of cathodic protection.

Paragraph 10.1.1.3 of NACE Standard RP0169–96 recommends that operators use close-interval surveys where they are practicable and sound engineering judgment indicates they are necessary.[2] For this reason and because we believe the general method of monitoring cathodic protection at established test stations may not always be sufficient, we have referenced the NACE provision in final § 195.573(a)(2). Although the final rule does not prescribe a frequency of close-interval surveys, operators will have to describe in their maintenance procedures the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of the NACE Standard, and then follow those procedures.

In order to provide operators with time to prepare for compliance with the new close-interval survey requirement, the compliance date for existing pipelines will not be mandatory until December 29, 2003.

Final § 195.573(b), which is based on proposed § 195.569(c), requires that operators must reevaluate their unprotected pipe and cathodically protect the pipe where active corrosion is found. Operators must determine if active corrosion exists by electrical survey where practical, or otherwise by a review and analysis of certain maintenance records and the pipeline environment. Proposed definitions of the terms ''active corrosion,'' ''electrical survey,'' and ''pipeline environment'' are combined with other definitions in final § 195.553. Also, final § 195.573(b) applies to ''pipe'' rather than ''pipelines'' as proposed, because we did not intend for the proposed rule to apply to unprotected breakout tank bottoms. Integrity inspection of the bottoms of breakout tanks is covered by existing § 195.432.

[2] Paragraph 10.1.1.3 reads: Where practicable and determined necessary by sound engineering practice, a detailed (close-interval) potential survey should be conducted to (a) assess the effectiveness of the cathodic protection system; (b) provide base line operating data; (c) locate areas of inadequate protection levels; (d) identify locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or (e) select areas to be monitored periodically.

Equilon, Environmental Defense, and NACE argued that because unprotected pipelines may deteriorate as they age, operators should reevaluate these pipelines at intervals of less than 5 years, the maximum interval proposed in the NPRM. They suggested that to be consistent with part 192 we set the maximum interval at 3 years, not to exceed 39 months. Like these commenters, Iowa also saw a need to add 3 months to the maximum interval, whether it be 5 or 3 years, to provide scheduling and operational flexibility.

In view of the three comments favoring a 3-year inspection interval and the Technical Hazardous Liquid Pipeline Safety Standards Committee's unanimous recommendation to establish a maximum 3-year interval (see the Advisory Committee Consideration heading below), we reconsidered whether the appropriate maximum inspection interval should be 3 or 5 years. We considered the fact that the relation between relevant risk factors on unprotected pipelines and an appropriate inspection interval is uncertain. As discussed in the NPRM, we are also seeking to make the corrosion control standards for gas and hazardous liquid pipelines consistent wherever reasonable. At present part 192 prescribes a maximum inspection interval of 3 years for unprotected gas pipelines; and part 195 prescribes 5 years. Although there is no evidence in the record to demonstrate conclusively the advantage of a 3-year interval over a 5-year interval, taking into consideration the risk to the public and environment, we believe the more conservative 3-year interval is the prudent choice. Furthermore, we believe this choice is reasonable based on our enforcement experience, as well as, discussions with industry representatives which indicate that many hazardous liquid pipeline operators inspect their unprotected pipelines every 3 years. Therefore, the final rule is changed from the proposed maximum 5-year interval to a maximum 3-year interval.

In order to provide operators with time to prepare for compliance with the new 3-year inspection interval, compliance will not be mandatory until December 29, 2003.

Equilon and NACE suggested that in-line inspection may be a more appropriate alternative to electrical survey than analysis of leak repairs and other matters as proposed in § 195.569(c). However, the proposed rule did not limit an operator's choice of alternatives to an analysis of leak repairs. Rather, where electrical surveys are impractical, we proposed the use of any alternative means of determining whether active corrosion exists, as long as that means includes a review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. Under the final rule, if operators have in-line inspection data and want to use it as an alternative to electrical surveys where such surveys are impractical, they may do so provided they interpret the data in light of the required review and analysis of other pertinent information.

WUTC suggested we put the following sentence in the final rule: ''Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.'' We discussed in the NPRM why we did not propose such a requirement. We stated that it is unnecessary to direct such action due to the existing requirements under § 195.401(b). This section requires operators to correct within a reasonable time any condition that could adversely affect safe operation of a pipeline system; and if an immediate hazard exists, to cease operating the affected part of the system until the condition is corrected. In addition, on pipelines that could affect high consequence areas, new § 195.452(h) requires operators to take prompt actions to address integrity issues and to repair certain conditions within specific time limits. However, in light of WUTC's comment, we established § 195.573(e) to draw attention to the remedial action required by existing §§ 195.401(b) and 195.452(h).

WUTC also was concerned that the discretion built into the proposed definition of ''active corrosion'' would allow operators to ignore corrosion leaks detrimental to public safety or the environment. WUTC suggested we require operators to classify and schedule all corrosion leaks for repair. In response, we believe the purpose of proposed § 195.569(c) is to require operators to look for and cathodically protect certain areas of corrosion before leaks occur. Operator response to leaks, whether due to corrosion or other causes, is not covered by new subpart H. Leak response is governed by existing § 195.401(b) or § 195.452(h), which together require timely corrective action for all unsafe conditions on pipelines subject to Part 195.

Section 195.575. This standard requires electrical isolation to provide for adequate cathodic protection. The standard is based on proposed § 195.571.

Enron expressed support for the proposed rule; however, Tosco believed we should specify the frequency of inspection and electrical tests.

We did not adopt Tosco's comment because the purpose of the proposed inspection and electrical tests is to ensure that electrical isolation is adequate when it is installed. All post-installation inspections and tests of cathodic protection facilities are covered by final § 195.573.

In final paragraph (d), for clarity, we changed the proposed wording ''where a combustible atmosphere is anticipated'' to read ''where a combustible atmosphere is reasonable to foresee.'' Similarly in paragraph (e), we changed the proposed ''where fault currents or unusual risk of lightning may be anticipated'' to read ''where it is reasonable to foresee fault currents or an unusual risk of lightning.''

Section 195.577. The purpose of this standard, which is based on proposed § 195.575, is to minimize the adverse effects of stray currents on pipelines and the effects of impressed currents on adjacent structures. Expressing support for the proposed rule, Tosco stated that the proposed program to identify, test for, and minimize the detrimental effects of stray currents may result in operators participating in corrosion coordinating groups. We agree that such coordination may be necessary for an effective program.

Section 195.579. This standard, proposed as § 195.577, requires operators to investigate the effects of transporting hazardous liquid or carbon dioxide which could corrode the pipeline, and take adequate steps to mitigate corrosion. Tosco suggested that in the final rule we clarify that the investigation may be done by review of operating history. A review of relevant operating history may be a satisfactory investigation in some situations. However, we did not explicitly include this option in final § 195.579. We used the proposed wording because we think it is broad enough to permit operators to use any method of investigation that will provide a sound basis for deciding how to mitigate internal corrosion adequately.

Under proposed § 195.577(d), if operators discover harmful corrosion inside removed pipe, they must investigate further to determine if additional harmful corrosion exists in the vicinity of the removed pipe. Phillips suggested that the extent of further investigation should depend upon the type of corrosion found and whether that corrosion could be expected to extend beyond the exposed segment. We do not believe there is a clear understanding of the relationship between the type of corrosion and the likelihood of finding similar corrosion in the vicinity of removed pipe to justify limits on a requirement for additional investigation. The effect of corrosive liquids on pipe may be too variable to make such predictions with accuracy. Therefore, we did not adopt Phillips' comment.

Section 195.581. This section, based on proposed § 195.579, modifies an existing requirement (§ 195.416(i)) that all pipelines exposed to the atmosphere must be protected against atmospheric corrosion by a suitable coating. Final § 195.581 gives operators flexibility when deciding to coat pipelines where atmospheric corrosion will be limited to a light surface oxide, or will not affect the safe operation of the pipeline before the next scheduled inspection. Splash zones of offshore pipelines and soil-to-air interfaces of onshore pipelines are omitted from this exception.

Iowa opposed allowing pipe with metal loss to remain unprotected or unrepaired. Iowa stated that public safety should not depend on an operator's judgment of whether a corroding pipe will not fail before the next inspection (which could be up to 3 years). Yet under the proposed rule, if an operator chose not to coat, it would have to show that testing, investigation, or experience supports the decision. In other words, safety would not depend solely on an operator's judgment. Also, the need for coating would be reviewed again in 3 years. A 3-year delay in coating a pipeline judged to be safe should not jeopardize public safety, considering that atmospheric corrosion generally progresses at a slow rate. Therefore, we did not adopt Iowa's comment. Nevertheless, mindful of Iowa's concern, we edited the final wording to clarify that any decision not to coat a particular pipeline must be supported by testing, investigation, or experience relevant to that pipeline.

Tosco called the proposed rule ''a positive revision.'' However, Enron recommended that we add ''active'' as a descriptor of ''atmospheric corrosion.'' It believed the term ''active atmospheric corrosion'' would clarify that the rule does not apply to harmless corrosion. We did not adopt Enron's comment because we think the proposed exceptions will satisfy Enron's objective. Also, ''active atmospheric corrosion'' is a term that may not be in general use in the industry.

Section 195.583. Under this section, proposed as § 195.581, operators must periodically inspect exposed pipelines for atmospheric corrosion, giving particular attention to areas such as soil-to-air interfaces. Onshore pipelines must be inspected every 3 years; and offshore pipelines every year. If any inspection reveals atmospheric corrosion, the operator must protect the pipeline against atmospheric corrosion in accordance with § 195.581.

Enron, Equilon, Iowa, and NACE advocated adding a 3 months grace period to the maximum 3-year inspection interval. We agree that this period is useful to allow operators scheduling and operational flexibility, and included it in final § 195.583.

Tosco wanted to make certain that the proposed remedial action would not be required for light surface oxide. By the cross reference to § 195.581, final § 195.583 allows operators latitude when deciding to coat pipelines which exhibit only a light surface oxide.

AEC urged us to allow operators to use means of assessment other than periodic visual inspection. As an example, AEC commented that by using in-line inspection and a corrosion growth model, operators could predict when a pipeline should be reinspected or repaired. This approach, according to AEC, would enable operators to allocate resources for maximum benefits instead of periodically scattering them across entire systems. AEC's comment indicates two things: first, AEC apparently misunderstood the proposed rule to mandate visual inspection; and second, AEC would like operators themselves to decide appropriate inspection frequencies with the aid of a corrosion growth model. As to the first item, the proposed rule would not limit operators to using visual means of inspection. They could use any means capable of detecting atmospheric corrosion, including in-line inspection devices. As to growth models, AEC did not suggest which model, if any, can successfully predict the growth of atmospheric corrosion on exposed pipelines in changing and varied environments. Furthermore, AEC did not suggest how operators would decide when to inspect exposed pipe that has no history of corrosion. Since the record of this rulemaking proceeding lacks information on these important issues, we have adopted the proposed inspection frequencies as final. However, we would welcome receiving more complete information that could possibly serve as a basis for changing the rule as AEC suggests.

AEC also suggested we extend the proposed maximum inspection interval for onshore pipelines from 3 years to 5 years. It believes that extending the time to 5 years is appropriate because atmospheric corrosion rates are low, and exposed pipe is typically located outside high consequence areas where the maximum interval for reevaluation of pipeline integrity is 5 years (see § 195.452(j)(3)). In developing the proposed rule, we considered whether 3 or 5 years would be the appropriate maximum interval. We proposed 3 years primarily because the ASME B31.4 Code, a widely accepted consensus standards code for hazardous liquid pipelines, specifies a minimum 3-year inspection frequency for atmospheric corrosion onshore. Generally, atmospheric corrosion rates are found to be low and therefore, we must assume this factor was considered when the 3-year consensus standard was adopted. However, a low rate by itself does not seem to justify a longer interval. Also, the 5-year interval for integrity reevaluation in high consequence areas is based on various factors besides corrosion rate, including the time needed to carry out in-line inspections or pressure testing on the pipelines involved. Moreover, the 5-year reevaluation applies in addition to other monitoring frequencies required by part 195, such as annual cathodic protection monitoring and biweekly right-of-way inspections. Yet, we did not intend the 5-year period to serve as a yardstick for determining the adequacy of other monitoring frequencies.

Finally, AEC was concerned about the possible adverse consequences of visually inspecting soil-to-air interfaces on pipe spans over creeks and ravines. AEC suggested that if the interface is on a steep bank, the process of visually examining the pipe could accelerate bank erosion causing water pollution and overstress of the pipeline. We believe the proposed inspection requirement is flexible enough to allow operators to take precautions in inspecting soil-to-air interfaces on steep banks to avoid or minimize the disturbance AEC foresees. Should a disturbance occur that affects the safe operation of the pipeline, the operator would have to correct the problem. We did not change the final rule as a result of this comment.

Section 195.585. This section, which is substantively the same as proposed § 195.583, requires operators to take certain actions to correct corroded pipe. If general corrosion reduces pipe wall thickness to less than that required for the maximum operating pressure of the pipeline or if localized corrosion pitting exists to a degree that leakage might result, the operator must: replace the pipe; repair the pipe; or reduce the maximum operating pressure commensurate with the strength of the pipe. We edited the final rule to clarify that it is the ''maximum operating pressure'' that must be reduced.

Environmental Defense believed this section also should require operators to account for why corrosion has become so advanced. This commenter suggested operators should review their corrosion control systems to ensure that further harmful corrosion will not occur. We believe the combination of cathodic protection criteria under § 195.571 and periodic monitoring under § 195.573 will accomplish the objective of this comment. Whenever an operator discovers a corrosion control deficiency, it must review its corrosion control system and make adjustments as necessary to provide adequate protection against corrosion. If adequate protection cannot be achieved, the pipe involved may have to be replaced.

Section 195.587. This section is based on proposed § 195.585. It authorizes, but does not require, operators to use the widely accepted ASME B31G criteria for determining the remaining strength of corroded steel pipe.

Iowa fully supported the proposed rule. In contrast, WUTC was concerned that because ASME B31G allows wall loss of up to 80 percent without repair or replacement, it does not provide a reasonable measure of strength needed to withstand cyclical stresses, environmental loads, and other combined forces.

Although WUTC is correct, we consider B31G to be a guide to the capability of corroded pipe to withstand internal pressure. Final § 195.587 advises operators that B31G sets limits on use of the criteria. One limitation states that a pipe subject to significant secondary stresses should not be kept in service for the purpose of satisfying the criteria (paragraph 1.2(d)). To ensure that operators consider the effects of secondary stresses, in final § 195.585(a)(1), we added the words ''needed for serviceability'' immediately following ''strength of the pipe.'' Consequently, as a remedy for generally corroded pipe, operators may reduce maximum pressure commensurate with the pipe strength needed for serviceability. In determining the amount of pressure reduction required, operators may use B31G but also must consider any significant secondary stresses that may affect pipe serviceability.

Section 195.589. Under this section, proposed as § 195.587, operators must to keep current records or maps of the location of cathodically protected pipelines; cathodic protection facilities (including anodes) installed after the Final Rule takes effect; and structures bonded to cathodic protection systems. Additionally, operators must keep records of required maintenance activities including inspections, tests, analyses, checks, demonstrations, examinations, investigations, reviews, and surveys. These records must demonstrate the adequacy of corrosion control measures, or that corrosion requiring control measures does not exist. Operators will have to keep these records for at least 5 years, except that records related to § 195.569 (examination of pipeline when exposed); §§ 195.573(a) and (c) (monitoring external corrosion control); and §§ 195.579(b)(3) and (c) (monitoring internal corrosion control) will have to be kept for as long as the pipeline involved is in service.

Commenting on examinations of exposed pipe, Equilon and NACE believed that there is no need to keep records of good pipe for as long as the pipeline remains in service, and that there is no need to keep records of defective pipe after the latest in-line inspection. Equilon and NACE also contended that old records of internal corrosion monitoring are of little benefit without knowledge of flow rates, upstream pipeline operations, fluid properties, and other information. None of these records are generally available. We did not adopt either comment because the proposed records provide a useful history of pipeline condition and are easy to maintain in electronic form. The records may be helpful in assessing corrosion control needs, and could be used as a comparative base for evaluating in-line inspection data.

We also considered the Equilon and NACE comment that subpart H should not require operators to keep records of maintenance activities that occur before subpart H takes effect. Final § 195.589 specifically states that records must be kept for certain maintenance activities ''required by this subpart.'' For example, final § 195.589 does not require operators to keep records of corrosion control monitoring conducted before subpart H takes effect. However, until subpart H takes effect, § 195.404(c)(3) requires records of corrosion control inspections and tests required by subpart F of part 195. Operators must continue to maintain records established under that section for the retention period prescribed.

Tosco believed we should revise § 195.404(c)(3) to indicate that corrosion control records are required by subpart H. However, no confusion about the application of § 195.404(c)(3) to corrosion control should occur because this section applies only to inspections and tests ''required by this subpart,'' meaning, required by subpart F. After new subpart H goes into effect, Subpart F will no longer require corrosion control inspections and tests.

Phillips argued that the current 2-year retention requirement in § 195.404(c)(3) is adequate for auditing compliance, since 2 years of records show the current state of corrosion control. However, as we explained in the NPRM, 5 years is the minimum retention period that will assure the availability of records for our compliance auditing.

Environmental Defense stated that it would help government inspectors determine the adequacy of cathodic protection systems if we required operators to keep records of the location of existing cathodic protection facilities and not just those facilities installed after subpart H takes effect. While this suggestion has merit, we did not propose to require records of existing facilities due to the difficulty of creating such records, particularly for galvanic anode systems. Also, in our experience the lack of such a requirement has not caused a significant problem due to the number of operators who keep records of the location of existing corrosion control facilities.

Format and Organization

In accordance with **Federal Register** guidelines, we drafted final subpart H in an easier to read and understand format. Section headings are in the form of questions. We minimized passive voice and used the word ''you'' as a substitute for ''operator.'' Also, a few proposed sections were eliminated, combined with other sections, or separated into two or more sections. This Final Rule also changes §§ 195.5, 195.402, 195.404 and removes §§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, 195.418 to account for the new subpart H.

Advisory Committee Consideration

We presented the NPRM for consideration by the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) at a meeting in Washington, DC on February 7, 2001 (66 FR 132; Jan. 2, 2001). The THLPSSC is RSPA's statutory advisory committee for hazardous liquid pipeline safety. The committee has 15 members, representing industry, government, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. The committee voted unanimously to approve proposed subpart H but unanimously recommended that we require operators of bare or ineffectively coated pipe to inspect the pipe for external corrosion every 3 years. Our treatment of this recommendation is discussed in the Discussion of Comments section under section 195.573. A transcript of the February 7, 2001, meeting is available in Docket No. RSPA–98–4470.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures. RSPA does not consider this rulemaking to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. RSPA also does not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

We prepared a Final Regulatory Evaluation of the final rules and a copy is in the docket. The evaluation states that the rules are, on the whole, comparable either to existing safety standards currently in part 195 for hazardous liquid pipelines or to existing safety standards in part 192 for gas pipelines. The evaluation also states that the information presented at public meetings and meetings with industry and state representatives strongly suggests that imposing gas pipeline safety standards for corrosion control on hazardous liquid pipelines would not require a significant departure from customary safety practices on liquid pipelines.

An important feature of the final rules not found in part 192 or part 195 is the reference to cathodic protection criteria in NACE Standard RP0169–96. The evaluation states that these criteria are well known and widely followed throughout the industry, as indicated by meetings with industry representatives and by the voluntary standards in the ASME B31.4 Code. The evaluation further states that operators who do not now apply the NACE criteria are likely to apply the criteria in appendix D of part 192. The final rules would allow use of appendix D criteria under conditions stated in the NACE Standard. The evaluation concludes that there should be only minimal additional cost, if any, for operators to comply with the final rules.

Final § 195.563(c) (protecting effectively coated pipelines), § 195.567 (test leads), and § 195.573(a)(2) (monitoring cathodic protection by close-interval surveys or comparable technology) are changed from the proposed rules. However, the changes are consistent with industry practices and should not result in more than minimal additional costs.

Regulatory Flexibility Act. The final rules are consistent with customary practices for corrosion control in the hazardous liquid and carbon dioxide pipeline industry. Therefore, based on the facts available about the anticipated impacts of this rulemaking, I certify, pursuant to section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this rulemaking will not have a significant impact on a substantial number of small entities.

Executive Order 13084. The final rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13084, ''Consultation and Coordination with Indian Tribal Governments.'' Because the rules will not significantly or uniquely affect the communities of the Indian tribal governments and will not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Paperwork Reduction Act. Section 195.589 contains minor additional information collection requirements. Operators will be required to record the location of certain newly installed protection facilities, and keep these records for as long as the pipeline concerned is in service. In addition, records of inspections, tests, and other maintenance actions will have to be kept for as long as the pipeline is in service or for 5 years, depending on the nature of the information recorded. The present minimum retention period for records of inspections and tests is 2 years or the prescribed interval of test or inspection, whichever is longer (up to 5 years in some cases).

Hazardous liquid pipeline operators are required to keep records under Information Collection 2137–0047, Transportation of Hazardous Liquids by Pipeline: Record Keeping and Reporting Requirements. Operators already maintain records of the location of their protection facilities for as long as the pipeline is in service. They do so to find the facilities for their own purposes and to carry out existing monitoring requirements in part 195. Also, we believe the burden of retaining inspection, test, and survey records for the longer period will be minimal. These records are largely computerized and maintaining these records in a computer file represents very minimal costs. Because the additional paperwork burdens of this final rule are likely to be minimal, we believe that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary.

Unfunded Mandates Reform Act of 1995. This rulemaking will not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It will 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 rule.

National Environmental Policy Act. We have analyzed the final rules for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the rules parallel present requirements or practices, we have determined they will not significantly affect the quality of the human environment. An environmental assessment document is available for review in the docket. We also made a finding of no significant impact.

Impact on Business Processes and Computer Systems. We do not want to impose new requirements that mandate business process changes when the resources necessary to implement those requirements could otherwise be applied to ''Y2K'' or related computer problems. The final rules do not mandate business process changes or require modifications to computer systems. Because the rules do not affect the ability of organizations to respond to those problems, we have not delayed the effectiveness of the requirements.

Executive Order 13132. The final rules have been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). The final rules do not contain any regulation that (1) has substantial direct effects 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; (2) imposes substantial direct compliance costs on State and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply. Nevertheless, during our review of the existing corrosion control standards, representatives of state pipeline safety agencies gave us advice both in private sessions and in the two public meetings we held. In addition, our pipeline safety advisory committees, which include representatives of state governments, were, on two occasions in 1999, briefed on the corrosion control review project.

Executive Order 13211. This rulemaking is not a ''Significant energy action'' under Executive Order 13211. It 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, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects in 49 CFR Part 195

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

In consideration of the foregoing, 49 CFR part 195 is amended as follows:

PART 195—[AMENDED]

1. 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.

2. Section 195.3 is amended by adding paragraphs (b)(8) and (c)(7) to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(b) * * *

(8) NACE International, 1440 South Creek Drive, Houston, TX 77084.

(c) * * *

(7) NACE International (NACE):

(i) NACE Standard RP0169–96, ‘‘Control of External Corrosion on Underground or Submerged Metallic Piping Systems’ (1996).

(ii) [Reserved]

3. Section 195.5(b) is revised to read as follows:

§ 195.5 Conversion to service subject to this part.

* * * * *

(b) A pipeline that qualifies for use under this section need not comply with the corrosion control requirements of subpart H of this part until 12 months after it is placed into service, notwithstanding any previous deadlines for compliance.

* * * * *

4. Section 195.402(c)(3) is revised to read as follows:

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

* * * * *

§ 195.404 [Amended]

5. In § 195.404, paragraph (a)(1)(v) is removed, and paragraphs (a)(1)(vi) through (a)(1)(viii) are redesignated as paragraphs (a)(1)(v) through (a)(1)(vii).

§§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, 195.418 [Removed]

6. The following sections are removed and reserved: §§ 195.236, 195.238, 195.242, 195.244, 195.414, 195.416, and 195.418.

7. Subpart H is added to read as follows:

Subpart H—Corrosion Control

Sec.

Subpart H—Corrosion Control

§ 195.551 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for protecting steel pipelines against corrosion.

§ 195.553 What special definitions apply to this subpart?

As used in this subpart—

Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.

Buried means covered or in contact with soil.

Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

You means operator.

§ 195.555 What are the qualifications for supervisors?

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under § 195.402(c)(3) for which they are responsible for insuring compliance.

§ 195.557 Which pipelines must have coating for external corrosion control?

Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is—

(a) Constructed, relocated, replaced, or otherwise changed after the applicable date in § 195.401(c), not including the movement of pipe covered by § 195.424; or

(b) Converted under § 195.5 and—

(1) Has an external coating that substantially meets § 195.559 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

§ 195.559 What coating material may I use for external corrosion control?

Coating material for external corrosion control under § 195.557 must—

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;

(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(c) Be sufficiently ductile to resist cracking;

(d) Have enough strength to resist damage due to handling and soil stress;

(e) Support any supplemental cathodic protection; and

(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

§ 195.561 When must I inspect pipe coating used for external corrosion control?

(a) You must inspect all external pipe coating required by § 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

(b) You must repair any coating damage discovered.

§ 195.563 Which pipelines must have cathodic protection?

(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in § 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

(b) Each buried or submerged pipeline converted under § 195.5 must have cathodic protection if the pipeline—

(1) Has cathodic protection that substantially meets § 195.571 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

(c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection.[1] Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.

(d) Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.

(e) Unprotected pipe must have cathodic protection if required by § 195.573(b).

§ 195.565 How do I install cathodic protection on breakout tanks?

After October 2, 2000, when you install cathodic protection under § 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels (79.5m^3) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. However, installation of the system need not comply with API Recommended Practice 651 on any tank for which you note in the corrosion control procedures established under § 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

[1] A pipeline does not have an effective external coating material if the current required to cathodically protect the pipeline is substantially the same as if the pipeline were bare.

§ 195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?

(a) *General.* Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.

(b) *Installation.* You must install test leads as follows:

(1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

(2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.

(3) Prevent lead attachments from causing stress concentrations on pipe.

(4) For leads installed in conduits, suitably insulate the lead from the conduit.

(5) At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(c) *Maintenance.* You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with § 195.571.

§ 195.569 Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under § 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

§ 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169–96 (incorporated by reference, see § 195.3).

§ 195.573 What must I do to monitor external corrosion control?

(a) *Protected pipelines.* You must do the following to determine whether cathodic protection required by this subpart complies with § 195.571:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169–96 (incorporated by reference, see § 195.3).

(b) *Unprotected pipe.* You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

(1) Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) For the period in the first column, the second column prescribes the frequency of evaluation.

Period	Evaluation frequency
Before December 29, 2003.	At least once every 5 calendar years, but with intervals not exceeding 63 months.
Beginning December 29, 2003.	At least once every 3 calendar years, but with intervals not exceeding 39 months.

(c) *Rectifiers and other devices.* You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier	At least six times each calendar year, but with intervals not exceeding 2½ months.
Reverse current switch.	
Diode	
Interference bond whose failure would jeopardize structural protection.	
Other interference bond.	At least once each calendar year, but with intervals not exceeding 15 months.

(d) *Breakout tanks.* You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under § 195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

(e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by § 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under § 195.452, you must correct the deficiency as required by § 195.452(h).

§ 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

§ 195.577 What must I do to alleviate interference currents?

(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

§ 195.579 What must I do to mitigate internal corrosion?

(a) *General.* If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

(b) *Inhibitors.* If you use corrosion inhibitors to mitigate internal corrosion, you must—

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7½ months.

(c) *Removing pipe.* Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under § 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

(d) *Breakout tanks.* After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under § 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.

§ 195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§ 195.583 What must I do to monitor atmospheric corrosion control?

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by § 195.581.

§ 195.585 What must I do to correct corroded pipe?

(a) *General corrosion.* If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you—

(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) *Localized corrosion pitting.* If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

§ 195.587 What methods are available to determine the strength of corroded pipe?

Under § 195.585, you may use the procedure in ASME B31G, ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' or the procedure developed by AGA/Battelle, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk),'' to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

§ 195.589 What corrosion control information do I have to maintain?

(a) You must maintain current records or maps to show the location of—

(1) Cathodically protected pipelines;

(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and

(3) Neighboring structures bonded to cathodic protection systems.

(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §§ 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

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Administrator.

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