Exhibit No. ______ (DMC-4)
Docket No. TO-011472
Witness: Dan Cummings

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Washington Utilities and Transportation Commission,	)	DOCKET NO. TO-011472
Complainant,	)	
v.	)	
Olympic Pipe Line Company, Inc.	)	
Respondent.	)	

EXHIBIT TO
REBUTTAL TESTIMONY OF
DAN CUMMINGS

OLYMPIC PIPE LINE COMPANY

June 11, 2002

1650 Federal Register / Vol. 67, No. 9 / Monday, January 14, 2002 / Rules and Regulations

normal business hours in the FCC Reference Center (Room CY–A257) at its headquarters, 445 12th Street, SW., Washington, DC 20554, or may be purchased from the Commission's copy contractor, International Transcription Service, Inc., (202) 857–3800, 1231 20th Street, NW., Washington, DC 20036, or may be reviewed via Internet at *http://www.fcc.gov/csb/*.

In this document we make non-substantive rule changes to correct errors in the publication of part 76 of the Commission's rules. With this action, we complete the Commission's biennial review of the public file, notice, recordkeeping, and notice requirements applicable to cable operators under part 76 of the Commission's rules.

Need for Correction

As published, the final regulations contain errors which may prove to be misleading and need to be clarified.

List of Subjects in 47 CFR Part 76

Multichannel video and cable television service.

Federal Communications Commission.
William F. Caton,
Deputy Secretary.

Accordingly, 47 CFR part 76 is corrected by making the following correcting amendments:

PART 76—MULTICHANNEL VIDEO AND CABLE TELEVISION SERVICE

1. The authority citation for Part 76 continues to read as follows:

Authority: 47 U.S.C. 151, 152, 153, 154, 301, 302, 303, 303a, 307, 308, 309, 312, 315, 317, 325, 338, 339, 503, 521, 522, 531, 532, 533, 534, 535, 536, 537, 543, 544, 544a, 545, 548, 549, 552, 554, 556, 558, 560, 561, 571, 572, 573.

§ 76.305 [Removed]

2. Remove § 76.305.

3. Add Note to § 76.309 to read as follows:

§ 76.309 Customer service obligations.

* * * * *

Note to § 76.309: Section 76.1602 contains notification requirements for cable operators with regard to operator obligations to subscribers and general information to be provided to customers regarding service. Section 76.1603 contains subscriber notification requirements governing rate and service changes. Section 76.1619 contains notification requirements for cable operators with regard to subscriber bill information and operator response procedures pertaining to bill disputes.

4. Add Note 4 to § 76.630 to read as follows:

§ 76.630 Compatibility with consumer electronic equipment.

* * * * *

Note 4 to § 76.630: Cable operators must comply with the notification requirements pertaining to the waiver of the prohibition against scrambling and encryption, and comply with the public file requirement in connection with such waiver.

5. Section 76.1510 is revised to read as follows:

§ 76.1510 Application of certain Title VI provisions.

The following sections within part 76 shall also apply to open video systems; §§ 76.71, 76.73, 76.75, 76.77, 76.79, 76.1702, and 76.1802 (Equal Employment Opportunity Requirements); §§ 76.503 and 76.504 (ownership restrictions); § 76.981 (negative option billing); and §§ 76.1300, 76.1301 and 76.1302 (regulation of carriage agreements); provided, however, that these sections shall apply to open video systems only to the extent that they do not conflict with this subpart S. Section 631 of the Communications Act (subscriber privacy) shall also apply to open video systems.

§ 76.1700 [Amended]

6. Section 76.1700 is amended by removing and reserving paragraph (a)(1).

§ 76.1702 [Amended]

7. Section 76.1702 is amended the first time it appears by removing the editorial note. Section 76.1702 is further amended by removing it the second time it appears in its entirety.

§ 76.1802 [Amended]

8. Section 76.1802 is amended the first time it appears by removing the editorial note. Section 76.1802 is further amended by removing it the second time it appears in its entirety.

[FR Doc. 02–766 Filed 1–11–02; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Parts 195

[Docket No. RSPA–99–6355; Amendment 195–74]

RIN 2137–AD61

Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria)

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

ACTION: Final rule.

SUMMARY: This final rule finalizes repair provisions for hazardous liquid pipelines. These provisions were initially proposed in the previous rulemaking action which addressed requirements for pipeline integrity management programs in high consequence areas for operators owning or operating 500 or more miles of hazardous liquid or carbon dioxide pipeline (Integrity Management rule.) In the Integrity Management rule, we requested comment on the repair and mitigation provisions, because the provisions were substantially modified from those originally proposed in the notice of proposed rulemaking. This final rule also makes several non-substantive corrections and clarifications to other provisions of the Integrity Management rule.

DATES: This rule is effective May 29, 2001, except for paragraph (h) of § 195.452 which takes effect February 13, 2002. The incorporation by reference of certain publications in this rule is approved by the Director of the Federal Register as of February 13, 2002.

FOR FURTHER INFORMATION CONTACT: Mike Israni, (202) 366–4571, or by e-mail: *mike.israni@rspa.dot.gov*, regarding the remediation provisions in paragraph (h) or any other provisions of the integrity management rule; or the Dockets Facility (202) 366–9329, for copies of this final rule or other material in the docket. All materials in this docket may be accessed electronically at *http://dms.dot.gov*. General information about the RSPA/Office of Pipeline Safety (OPS) programs may be obtained by accessing OPS's Internet homepage at *http://ops.dot.gov*.

SUPPLEMENTARY INFORMATION:

Background

On December 1, 2000, RSPA published a final rule (65 FR 75378) that prescribed integrity management program requirements for pipeline operators who own or operate 500 or more miles of pipeline transporting hazardous liquids or carbon dioxide. Under the Integrity Management rule, operators are required to develop and implement integrity management programs that focus on hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. High consequence areas are defined as: populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways.

As part of the Integrity Management final rule, we requested comment on repair and mitigation provisions (§ 195.452(h).) We made this request because we substantially changed the initial provisions proposed in the notice of proposed rulemaking. We noted at that time that, at the end of the comment period (March 31, 2001), we would either publish a final rule modifying these repair provisions or stating that the provisions would remain unchanged. We received comments from six sources. Based on our analysis of the comments received, we modified paragraph (h). We discussed the comments, our responses, and changes made to these provisions below, in greater detail.

This document also makes several corrections and language clarifications to other provisions in § 195.452 and the Appendix C guidance. These changes do not affect the substance of any of the Integrity Management rule requirements. Rather, these revisions either correct the rule because of mistakes found since the rule was issued, or they clarify some of the language.

Corrections

The reference in paragraph (j)(4)(i) that the external monitoring technology provide an understanding of the line pipe equivalent to that obtained under paragraph (j)(2), was incorrect. The reference should be to the assessment methods listed in paragraph (j)(5), not to the evaluation described in paragraph (j)(2).

We deleted the sentence in paragraph (j)(4)(ii) requiring an operator to complete an integrity assessment within 180 days, after providing 180-days advance notice that it could not complete the five-year continual integrity assessment because of unavailable technology. If we did not remove this requirement, an operator would have to complete the re-assessment within the five-year period. Thus, the exception for a longer assessment period would be illusory.

We corrected the notification period in paragraph (j)(5)(iii), which required using alternative technology in the continual integrity assessment, from 60 days to 90 days. 90 days is consistent with the advance notice required for a baseline assessment that uses technology other than a hydrostatic test or an internal inspection tool.

We added paragraph number 1 to precede the first sentence in paragraph (l).

We corrected the grammar in several places in Appendix C.

Clarifications and Non-Substantive Revisions

We added carbon dioxide pipelines to § 195.452(a) to clarify that the integrity management program requirements for hazardous liquid pipelines to also apply to carbon dioxide pipelines regulated under Part 195.

We clarified in paragraphs (c)(1)(i) and (j)(5) that the three allowable assessment methods for the baseline and continual integrity assessments are to be applied to lap welded pipe and to low frequency ERW pipe.

We clarified that the periodic evaluation (paragraph (j)(2)) is to consider the results from the integrity assessments required by § 195.452, i.e., the baseline and continual integrity assessments.

We clarified the language in paragraph (j)(4)(i) regarding the justification and notice required for a variance based on engineering reasons.

We added the requirement that an address and facsimile number must be included for notifications required by the Integrity Management rule, rather than referencing these in other pipeline safety regulations. Due to the confusion of some operators about where to send a notification required by § 195.452 versus notifications required for other purposes, we added a new paragraph (paragraph (m)), which provides this information.

We revised several paragraphs in § 195.452 and Appendix C to make the terminology consistent with changes made to the terms used in paragraph (h).

We added another section to the guidance in Appendix C, which lists conditions an operator should include in its schedule for evaluation and remediation.

Advisory Committee Consideration

The Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) is the Federal advisory committee charged with the responsibility of advising on the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed hazardous liquid pipeline safety standards. The committee is composed of members with the requisite statutory expertise who represent industry, government, and the general public.

We discussed the repair provisions in paragraph (h) and comments received on those provisions by teleconference with the THLPSSC at its meeting on August 13, 2001. Before the discussion, the committee members were mailed a summary of comments on the repair provisions, and a supplement to the cost-benefit analysis that addressed these provisions.

At the August 13 meeting, seven of the twelve current members participated in the teleconference. These seven THLPSSC members voted unanimously to accept the repair provisions, provided OPS consider the changes and comments discussed during the teleconference.

The following is a list of the changes and comments that the THLPSSC asked OPS to consider:

• Reevaluate and relax the 60-day repair schedule for dents on the top of the pipe.
• Allow mitigative measures, other than repair.
• The provisions assume the use of in-line-inspection technology to identify defects although the rule allows both hydrostatic testing and other technologies for the integrity assessments.
• Provide that discovery of a defect occurs when an engineering analysis of the assessment results is completed.
• Let the section reflect that some internal inspection assessment results cannot be analyzed as quickly as others. For example, it typically takes a year following completion of the assessment to receive final results from a crack detection tool.
• Delete the section on other conditions requiring repair or move it to Appendix C as guidance material.

We discuss below all changes made to § 195.452(h) in response to the THLPSSC and other commenters.

Comments on Section 195.452(h)

On December 1, 2000, OPS issued a final rule addressing pipeline integrity management in high consequence areas for operators owning or operating 500 or more miles of hazardous liquid or carbon dioxide pipeline (65 FR 75378) (The Integrity Management Rule.) This rule included provisions addressing the repair of conditions found during an integrity assessment. The provisions were found in paragraph (h) of section 195.452, under the title "What actions must be taken to address integrity issues." However, because the repair provisions in the Integrity Management rule were substantially different from what we initially proposed in the notice of proposed rulemaking, we requested comment on the provisions. All other provisions of the Integrity Management rule were final and became effective May 29, 2001.

We received comments from the following six sources:

—One trade association with members affected by this rulemaking:
American Petroleum Association (API)
—Three individual liquid pipeline operators:
Tosco Corporation
Chevron Pipe Line Company
Colonial Pipeline Company
—One operator not directly affected by this rulemaking:
Enron Transportation Services Company (natural gas transmission)
—One Engineering company:
SEFBO Pipeline Bridge, Inc.

SEFBO did not comment directly on the repair provisions but expressed its support for pipeline integrity management programs and stressed the importance of considering safety issues relating to the support structures used by pipelines to cross high consequence and other sensitive areas.

Some of the comments we received about the repair provisions also addressed other portions of the final rule. As we only requested comment on the repair provisions in paragraph (h), this document will focus on those comments. If at some point we determine that substantive revisions to the final rule are necessary and we propose changes, we will then consider those comments.

Comments on Section 195.452(h)—"What actions must be taken to address integrity issues?"

1. General comments about paragraph (h):

API objected to use of the word repair throughout paragraph (h). API contended the exclusive focus of the rule on repairs undermined the holistic approach of the rule. API commented that a key principle throughout the rule is the integration of information, so appropriate mitigative actions can be taken based on a comprehensive assessment. API explained that although actions may consist of repair, other actions such as further testing and evaluation, environmental changes, operational changes, or administrative changes could be appropriate. API advised that the goal should be to ensure operators differentiate defects injurious to a pipeline's integrity from those that are not.

Tosco also commented that requiring repair in all instances was too inflexible, and operators must have the flexibility to address a wide range of conditions.

Response:

To assure the integrity of pipeline segments that could affect high consequence areas, Section 195.452 requires an operator to conduct a variety of assessments. The assessments include baseline and continual integrity assessments of the line pipe and periodic evaluations of entire pipeline systems, to assure the integrity of pipeline segments that could affect high consequence areas. This is accomplished through the continual identification and remediation of potential problems. We agree the word "repair" in paragraph (h) might be too narrow to encompass the range of actions an operator could take to address a problem. We intended paragraph (h) to reflect the broader actions an operator must take to address integrity issues that are identified. We further agree that all anomalies identified by an integrity assessment or information analysis might not require repair. Therefore, we replaced the word repair with remediate throughout paragraph (h). Remediate can encompass a broad range of actions, which include mitigative measures as well as repair, that an operator can take to resolve a potential integrity concern. Although we firmly believe repair is necessary to address many anomalies, we recognize repair may not be necessary in all instances. The rule provides the operator flexibility to determine the most appropriate action to take. However, we added language to ensure that whatever action is taken by an operator, it must be adequate to resolve the integrity concern on the pipeline for the long term. We also added a requirement that when an operator chooses to remediate a condition through a reduction in operating pressure, the pressure reduction is not to extend beyond 365 days without the operator taking further action to ensure the safety of the pipeline.

2. Section 195.452(h)(1)—General Requirements: In this paragraph we required an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and information analysis, and evaluate all anomalies and repair those that could reduce a pipeline's integrity. An operator was further required to follow § 195.422 in making a repair.

API objected to the words "prompt" and "all" because these words could be interpreted in their absolute sense; could cause confusion because of the required time frames for addressing certain conditions; and could lead inspectors to require operators to take costly actions to address insignificant anomalies. API recommended deleting these terms.

Tosco suggested the rule only require an operator to comply with § 195.22 when a repair is necessary.

Response:

As explained in the previous section, we replaced "repair" with "remediate" throughout paragraph (h), allowing for actions other than repair, in order to address integrity threatening pipeline conditions. This will allow an operator flexibility in how to address anomalous conditions on its pipeline.

We did not delete the terms "prompt" and "all." The pipeline safety regulations have long incorporated the term "prompt," with consistent enforcement; there is little disagreement between operators and inspectors about its meaning. For the listed conditions, we determined what a prompt time frame should be (viz., immediate, 60 days, 180 days), but leave it to the operator to determine appropriate time frames for other conditions. We kept the word "all" because it is a reasonable requirement for an operator to evaluate all conditions indicated by an integrity assessment or the information analysis, in order to determine the significance of each concern. Upon evaluation of the condition, the operator can then determine the appropriate further action to take, if any. We revised the language to clarify that an operator must evaluate all anomalous conditions (i.e., any condition that is irregular, abnormal, deviates from the norm, etc.) and remediate those conditions that could reduce the integrity of a pipeline.

The word "address" is used in the introductory paragraph to encompass the process an operator should go through to find and remedy anomalous conditions, i.e., discovery, evaluation, and remediation of the condition through repair or other mitigative action. Using language to capture the process is consistent with API's comment about the intended goal of the rule. By having an operator address all anomalous conditions raised by the integrity assessment or the information analysis, we envision a process that begins with discovery of a condition or anomaly that poses an integrity concern to the pipeline; continues with an evaluation that includes the analysis of other relevant data about the pipeline (this analysis could also be part of the discovery); and concludes with fixing the problem.

We did not add "if necessary," to the requirement about complying with

§ 195.422, as suggested by Tosco. The rule now uses the word remediate, which should alleviate any confusion about when compliance with § 195.422 is necessary. Section 195.422 applies only to repairs. If actions other than repair are taken, the requirements in the section do not apply.

3. Section 195.452(h)(2)—Discovery of a condition.

The discovery of a condition triggers the time frames (either required by the rule or the operator's schedule) for remediating the condition. We defined discovery as occurring when an operator has adequate information to determine the need for a repair, and we provided examples of when such information might be available, depending on the circumstances. The examples included the receipt of the preliminary internal inspection report, the gathering and integrating of other inspection information, and the receipt of the final internal inspection report. The date of discovery could be no later than the date of the integrity assessment results or the final report.

API objected to tying discovery to a specific point in time because discovery is not usually a single event but occurs over time as information is analyzed. API commented that other provisions of the Integrity Management rule require operators to integrate information from various sources, and tying the date of discovery to the date of the integrity results or receipt of the final report is inconsistent with the concept of integrating data. API maintained that too much emphasis is put on the use of internal inspection tools and the data collected from running these tools through a pipeline. API also commented that the emphasis on the results of in-line inspections in determining what action must be taken, is inappropriate and inconsistent with the rule's intent for information from multiple sources to be integrated in the assessment process. API suggested that rather than tying discovery to the integrity assessment results or final report, discovery should occur when an operator has integrated other inspections, tests, surveillance, controls, or pipeline integrity data with the final inspection report from an in-line inspection vendor or hydrostatic test. API believes this integration should be completed within 90 days from the receipt of the final inspection report.

Tosco expressed similar concerns and suggested the word "discovery" not be used, since it has the common meaning of when something is first found and might cause confusion with how the term is used in § 195.56. Instead, Tosco would tie the repair schedules to the determination that a condition requires mitigation, which would be an outcome of the ongoing assessment process.

Chevron also believed it is inappropriate to tie discovery to a specific event because discovery is a process that is subject to change with new information. Chevron suggested language changes identical to those recommended by API.

Response:

We contend that discovery triggers an operator's process to address a condition that could affect the integrity of a pipeline. Therefore, discovery has to occur at a specific point in time to start the period for evaluation and remediation of the condition. The use of the word "discovery" here is consistent with how the word has been used in other pipeline safety regulation. However, to allow flexibility the rule provides that the time of discovery can vary depending on circumstances, and does not define discovery to occur at the same time for every operator and every pipeline.

Discovery will depend on circumstances. We revised the rule to provide that discovery occurs when an operator has adequate information about a condition to determine the condition presents a potential threat to the integrity of the pipeline. The "when" for an operator to have sufficient information to make a determination will not be the same for every operator and every pipeline. Although the examples in paragraph (h) provide circumstances when discovery might occur, they were intended only as examples. We decided to eliminate the list as it is not exhaustive and may cause confusion. We did keep the performance-based standard to give an operator flexibility when deciding there is adequate information to determine a condition presents a potential threat to its pipeline. However, we put an upper limit on the length of the discovery process. An operator must promptly obtain the information from an assessment to ensure that remediation of a condition which could threaten a pipeline's integrity occurs soon after an integrity assessment. The discovery process (the process for obtaining the adequate information) will end 180 days after an integrity assessment unless an operator can demonstrate that the 180-day period is impracticable.

4. Section 195.452(h)(3)—Review of integrity assessment:

This paragraph, as proposed, required an operator to include in its schedule for evaluation and repair a schedule for promptly reviewing and analyzing integrity assessment results. After March 31, 2004, an operator's schedule had to provide for this review within 120 days of conducting each assessment. The operator also had to obtain and assess a final report within an additional 90 days.

API objected to setting a fixed period for the review of integrity assessment results. API commented that the language confused the role of the vendor who conducts a specific test or provides interpretive results, with the operator who conducts the integrity assessment and uses information from sources other than in-line inspections in performing those assessments. API explained that an operator contracts with the vendor for a specific service that is part of an overall integrity assessment.

API also expressed concern that increased demand for inspection services would likely affect the time in which tool vendors deliver the reports. API stated that it is unlikely that operators will be able to meet the deadlines for every tool run and for every type of tool, as many types of tools are on the leading edge of development. API suggested that the rule: require review of integrity tests and inspections (rather than assessments); provide for integrating other appropriate data with the inspection/test results; and allow for a delay in schedule beyond the specified deadlines as long as an operator provides a reasonable explanation for the delay.

Tosco commented that the two separate time periods is confusing; that if assessment of inspection results must be accomplished within 120 days, it is not clear what additional evaluation is required within 90 days of obtaining the report of an inspection.

Response: We wish to note: an integrity assessment should not be confused with an integrity management program. Integrity management applies to the entire pipeline. It is a process that uses the information from an integrity assessment, in conjunction with the periodic evaluation and information analysis, to better manage the risks posed to each pipeline segment that could affect a high consequence area. Assessment is only one part of an operator's integrity management program and applies only to the line pipe. In the integrity management rule an assessment is required as a baseline and then required, periodically, every five years to ascertain the condition of the line pipe in each pipeline segment that could affect a high consequence area. To perform this assessment an operator has a choice of technologies: hydrostatic testing; internal inspection devices; or other technology. The rule clearly states that it is the operator's responsibility to perform the required baseline and periodic assessments.

Integration of information is a critical part of an operator's integrity management program. An operator must conduct periodic evaluations, which are to include evaluating data from the information analysis. The evaluations must be conducted as frequently as needed to assure pipeline integrity, not just when an assessment is done. Thus, the rule leaves it to each operator to best determine the frequency for evaluating its pipelines. We further expect an operator to structure its program to bring the necessary information together at the appropriate time.

The requirement that an operator obtain and analyze an integrity assessment report by a specified time was intended to prompt an operator to obtain a timely report so that it could begin the repair of pipeline integrity-threatening conditions. However, after further analysis of this requirement we believe its implementation would be confusing and likely result in endless disagreements between operators and enforcement personnel. For example, an operator might have a condition on its pipeline that falls into the 60-day category. It could be argued that discovery occurred when the operator received a preliminary report of its integrity assessment, and that the operator was required to remediate the condition within 60 days after it received the report. However, the operator is supposed to have 120 days to review and analyze a preliminary report. Thus, there could be disagreement over whether the 60-day requirement negated the period for review and analysis, or whether the period for initial review and analysis gave the operator an additional 120 days before it was required to remediate the condition.

Furthermore, we realized that the intent of this provision is to ensure an operator promptly addresses anomalous conditions on its pipeline, not to create disagreements about when an operator receives a report, reviews the report, and whether the report was a preliminary or final report.

Rather than create a potential compliance and enforcement nightmare, we eliminated this provision from paragraph (h). Instead, we rewrote the provision (see discussion on discovery above) to give the operator flexibility in what information it uses, and what analysis it needs to discover a condition. Now an operator must promptly obtain sufficient information about a condition to make the determination that the condition presents a potential threat to the integrity of the pipeline. However, the obtaining of this information can take no longer than 180 days after an integrity assessment. 180 days after an integrity assessment, is considered sufficient time for an operator to obtain a report and any other information the operator needs to determine that a condition may present a threat. In limited instances, an operator may be able to demonstrate that the 180-day period is impracticable.

By having a performance-based requirement, yet establishing an upper limit on when discovery can occur, it should be clearer to an operator on how to comply. It should also be clearer to determine when there is a violation, for enforcement purposes.

The revised provisions ensure that an operator takes prompt action following an integrity assessment to remediate anomalous conditions and encourage operators to use sophisticated and developing technologies, because the operator will not be dependent on the report from the vendor.

5. Section 195.452(h)(4)—Schedule for repairs: This paragraph required an operator to complete repairs according to a schedule that prioritizes conditions for evaluation and repair. The schedule was based on risk factors used for establishing the baseline and continual integrity assessment schedules. An operator would be allowed to notify RSPA/OPS when it could not meet the schedule and provide a justification for the delay. Notice was to be sent to the address in § 195.58 or to the facsimile number in § 195.56.

API recommended the reference to the risk factors be deleted because the factors are appropriate for establishing re-inspection intervals but not for prioritizing mitigative actions.

Tosco questioned, in the event an operator could not meet its schedule, whether the notification required should also be sent to the appropriate State agency in those States that are certified under Section 60105 of the Federal Pipeline Safety Statute. Tosco also noted that because § 195.58 applies to subpart B and § 195.56 applies to Safety Related Condition reports, we should reference the integrity management notification in these sections.

Response:

It is likely the results of an integrity assessment will be the principal basis for scheduling a condition for remediation. These results will generally indicate the significance of anomalies so operators can establish their relative importance for remediation. However, RSPA recognizes that there may be other factors an operator needs to consider in prioritizing the conditions for remediation, and agrees that requiring an operator to base its schedule on risk factors is unnecessary. We deleted this requirement from the rule and will leave it to the operator to determine how best to set up a schedule for evaluation and remediation of conditions identified from the assessment. Of course, an operator must document the basis for how it prioritizes conditions in its schedule.

As for where an operator is to send a notification when it is unable to meet its schedule, the language clearly provides the address and facsimile numbers for sending the notification. Although we see no reason for confusion about where to send a notification, we added a new paragraph (m) to the integrity management rule that contains the address and facsimile number for sending notification. This paragraph now contains the current room number and facsimile number for sending any notification required by § 195.452.

The rule continues to require operator notification to RSPA/OPS. We will then ensure that the relevant Regional office receives the notification for forwarding to a certified State. Having the notification come to RSPA is consistent with the filing of other reports, such as the safety-related condition report and accident report. As RSPA plans to keep a data base of notifications, it is most practicable for it to be the notified agency rather than State safety agencies. It also prevents a burden to operators of trying to determine which agencies should be notified. Requiring all notifications under the Integrity Management rule first come to RSPA/OPS, eliminates any potential confusion about where a notification should be sent.

When a certified State adopts the integrity management regulations, it may also add a requirement for notification by intrastate hazardous liquid operators.

6. Section 195.452(h)(5)—Special requirements for scheduling repairs:

This paragraph provided a list of certain conditions that require either immediate repair, repair within 60 days, or repair within six months. This paragraph also listed other conditions an operator would be required to evaluate and repair, but did not specify the time frame.

Although not directly affected by this rulemaking, Enron maintained that the prescriptive time frames for certain conditions were not appropriate for the conditions, forcing operators to seek extensions. Enron further commented that the descriptions of the conditions were open to interpretation.

Immediate repair conditions: This subparagraph provided a list of conditions that require immediate repair. An operator is further required to temporarily reduce operating pressure or shut down the pipeline until the operator could complete the repair, basing the temporary operating pressure reduction on remaining wall thickness.

API acknowledged that the conditions we listed as immediate repair conditions are those where the indicated anomaly may suggest the potential for imminent failure. However, API objected to limiting an operator's actions to address these conditions to repair of the condition. API recommended renaming these immediate concern conditions, and allowing an operator to take actions other than repair. API gave the example of a pipeline over-designed for wall thickness, as able to remain in service at very low pressure and not subject to imminent failure, even with metal loss greater than 80 percent of nominal wall thickness.

API further stated that limiting an operator's discretion on reducing operating pressure to remaining wall thickness may be inappropriate in many situations (e.g., dents with indicated metal loss) and supported by engineering calculations. API suggested that the original wall thickness in some pipelines may have been above that needed to contain current maximum operating pressure, and recommended basing pressure reduction on an engineering assessment that includes all the potential factors that may contribute to pressure containment.

Chevron recommended we remove the condition of "dents on the top of the pipeline with any indicated metal loss" from the immediate repair category. Chevron agreed such dents may be serious, but contended there is insufficient data to prove that these types of anomalies are of immediate concern. Chevron also believed an immediate repair requirement related to such anomalies would be difficult to meet because corrosion internal inspection tools do not always identify such dents, and those vendors that claim the tools can identify such dents cannot correctly size and identify them. Chevron recommended we place these types of anomalies in the 60-day category, and reword the anomaly description to include known topside dents that exceed 6 percent of the nominal pipe diameter with any (emphasis in the original comments) indicated metal wall loss. In addition, Chevron recommended RSPA work with industry to develop a pressure calculation that will determine the level of pressure reduction required (dependent on the size of the dent) to operate the pipeline safely.

Response:

We allowed an operator latitude in how it addresses most conditions, by changing the word repair to remediate throughout paragraph (h). However, we firmly believe that certain conditions, due to the immediate threat they pose to a pipeline's integrity and to a high consequence area, are best addressed by repair. We continue to list these conditions as "Immediate repair conditions." An operator must repair these conditions; and until the repair is completed, either reduce operating pressure or shut down the pipeline.

We agree that a situation might exist where an over designed pipe segment operating at a lower pressure could withstand maximum operating pressure, even with 80% wall loss. However, we find it unacceptable for an operator not to immediately repair a segment of pipeline where less than 20 percent of original wall thickness remains. Wall loss exceeding 80% indicates something significant is occurring on the pipeline.

We also do not agree with Chevron's suggestion that "dents on top of the pipeline with indicated metal loss" do not require immediate repair because they are hard to identify. We acknowledge current inspection techniques may not readily identify dents with metal loss. The rule does not require an operator to identify such conditions. The rule simply specifies that when such conditions are identified, an operator must repair them immediately. This type of dent is also classified as an immediate concern in the most recent draft of API–1160, "Managing System Integrity for Hazardous Liquid Pipelines." Therefore, we are not removing this condition from the list of immediate repair conditions.

The reduction in operating pressure, or the shutdown of the pipeline, provides an additional margin of safety. This requirement is consistent with § 195.401(b). This established regulation requires an operator to correct conditions that could adversely affect safe operations in a reasonable time and not operate the affected part of the system until the condition is corrected, if it is of such a nature that it presents an immediate hazard to persons or property.

We agree that pressure reductions should be based on an engineering evaluation, and changed the final rule accordingly. Although it is appropriate to base the pressure reduction on the remaining wall thickness for corrosion, this may not be the best method on which to base a pressure reduction for dents and gouges. We modified the requirement so that an operator must calculate the temporary reduction in the operating pressure using the formula in section 451.7 of ASME/ANSI B31.4.

In response to concerns about the rule confusing the role of vendors with that of operators, we clarified the language in one of the listed conditions concerning the person responsible for making certain determinations about a condition. We revised the language so that now it is the person designated by the operator to evaluate assessment results, who is to determine whether an anomaly requires immediate action.

60-day conditions:

As proposed, this paragraph required an operator to schedule for evaluation and repair all dents (other than those listed as immediate repair conditions), regardless of size, located on the top of the pipeline (above the 4 and 8 o'clock position) within 60 days of discovery of the condition.

API agreed with placing special emphasis on investigating anomalies that represent potential excavation damage on the top of the pipe. However, API contended that requiring repair of any topside dent, regardless of size, would preclude operators from making appropriate engineering judgments about anomalies that differ in character and risk profile from one pipeline to another.

API contended that increasing sensitivities of inspection tools could result in "hundreds or even thousands" of topside line indications, only some of which will be a result of third-party damage. (Colonial and Chevron made the same comment). To better focus resources on areas of highest risk, API recommended we specify dents that are in excess of three percent of pipeline diameter and are located in a high population or other populated area, as 60-day conditions and include remaining dent-type defects as 6-month conditions. API believes this conservatively reduces by half the ASME B31.4 provisions, which require removal or repair of dents exceeding a depth of six percent of nominal diameter. API explained that the focus on high population areas and populated areas is appropriate because third-party activity is more likely to occur in these areas. (Chevron recommended these same changes). API further recommended excluding dents less than 0.25 inches for small diameter pipe (less than NPS 12) to recognize mill imperfections that fall within manufacturing tolerances. API maintained that operators have conducted verification digs on many such small defects identified by past in-line inspections to demonstrate that these indications do not threaten pipeline integrity.

Colonial reported in its experience, in-line inspection identified hundreds of bending shoe marks, smooth dents, and minor mill imperfections that fall within manufacturing tolerances. However, Colonial found these indications to be neither injurious to the pipeline nor the result of third-party damage. Colonial suggested that increased focus on these indications would result in dilution of resources and diversion of attention from higher risks. Colonial recommended we exclude "smooth dents, bending anomalies, and mill defects that may be identified through engineering analysis and data integration including data gathered from previous excavations and inspections."

Chevron recommended we limit the 60-day conditions to known topside dents in excess of six percent of the nominal pipe diameter with any indicated metal loss, and that occur within a high population area or other populated area.

Tosco would not limit the 60-day conditions to topside dents. Tosco explained that an operator must also evaluate dents located at the bottom of the pipe because they may indicate that the pipe has been damaged by lifting the line with excavation equipment.

Response:

Although commenters expressed concern about internal inspection tools not being able to detect immediate repair conditions, they also expressed concern about the tools finding too many of the 60-day conditions. We reconsidered what conditions an operator should address within 60 days from discovery. We decided to limit those conditions to large dents (i.e., those dents in excess of three percent of pipeline diameter) on the top of the pipeline and to dents on the bottom of the pipeline that contain stress concentrators because these types of dents are more likely to impair the integrity of the pipeline. We want the rule to encourage the use of more sophisticated inspection tools, as these tools become available. By modifying the list of 60-day conditions so that operators can better focus resources on remediating those conditions most likely to pose a threat to the integrity of a pipeline and to a high consequence area, operators will be encouraged to use more sensitive tools.

We do not agree that the 60-day conditions should be limited to conditions found in high-population and populated areas. While it may be possible that third-party damage is more likely to occur in these areas, such damage can also occur in other areas. There is no reason why third party damage to a pipeline in an unusually sensitive environmental area should not be addressed as promptly as third party damage to a pipeline in another high consequence area. We make no distinction in the final rule between dents identified in populated areas and dents identified in other areas defined as high consequence.

We did not make the change suggested by Tosco to include all dents located on the bottom of the pipe. We recognize that excavation damage limited to the bottom of pipe can occur, but understands it to be much less prevalent. However, we included under the 60-day conditions dents located on the bottom of the pipeline that have other indicators of damage, such as evidence of cracks or stress risers within the dent that would indicate a need for more immediate action. Significant dents (i.e., those dents with a depth greater than six percent of the pipe's diameter) on the bottom of pipe would require remediation within 180 days of discovery. An operator must also evaluate and remediate any other dents on the bottom of the pipeline within a reasonable time.

Six-month conditions: This paragraph listed several conditions an operator would have to schedule for evaluation and repair within six months following discovery.

API recommended the list of 6-month conditions be completely rewritten and offered changes it believes use technically sound descriptions of the potential anomalies. API's revisions include the concept of minimum detection limits, particularly with respect to dent-type anomalies. API claimed this would prevent the inappropriate diversion of safety resources that could result from a requirement to address "all dents, regardless of size" as detection capabilities increase. API echoed the comments of Colonial, discussed above, that in-line inspection companies have identified imperfections that fall within manufacturing tolerances and operators have conducted many verifying digs to demonstrate that these anomalies do not affect pipeline integrity. Colonial's comments in that regard are applicable also.

Chevron also recommended a complete rewrite of the six-month conditions for the same reasons as API, and proposed language substantially the same as API's. Differences exist in addressing situations in which "predicted burst pressure" is less than established maximum operating pressure (API uses the term "safe operating pressure"). API would limit the need to evaluate metal loss located at foreign pipeline crossings, to instances with greater than 50 percent wall loss, while Chevron would address those with greater than 30 percent wall loss.

Enron also commented that several of the listed conditions could require an expensive, time consuming, and non-productive diversion of safety resources. Enron believed evaluating dents with metal loss or dents affecting pipe curvature at a girth or seam weld, could result in numerous excavations. Many in-line inspection devices cannot identify such seams and having to investigate such dents, regardless of their depth, could require significant resources for little safety benefit. Enron raised the same concern regarding the need for unnecessary physical inspections to evaluate and repair corrosion of or along seam welds. Enron suggested that the six-month conditions only specify narrow axial external corrosion. Enron commented that the rule did not appear to allow pressure reduction as an option for addressing areas of general corrosion with predicted metal loss of greater than 50 percent of wall thickness.

Response:

To be consistent in language throughout paragraph (h), we now list the six-month conditions as 180-day conditions. We re-categorized some of the dents listed as 60-day conditions into the 180-day category because they are less severe. To avoid including minor and non integrity-threatening dents that fall within manufacturing tolerance limits, we revised the list of conditions to include dents greater than two percent of pipe diameter. The 180-day conditions category is consistent with the most recent draft of API–1160, "Managing System Integrity for Hazardous Liquid Pipelines," except for minor differences. We included gouges and grooves greater than 12.5 percent of wall thickness, which are not in the API–1160 draft.

Enron's concern regarding potential diversion of resources to address dents affecting seam welds was based on the perception that an operator would need to excavate most, or all dents to determine if they impacted a seam weld (similar logic underlies Enron's concern about the need to investigate corrosion along seam welds). We do not intend to require an excavation in order to identify the location of welds. We clarified the final rule to eliminate confusion by setting de-minimus values for certain dents.

We also clarified an apparent inconsistency in which we listed weld anomalies with predicted metal loss greater than 50 percent of wall thickness and corrosion of or along seam welds as 6-month conditions. We deleted from the list weld anomalies with a predicted metal loss greater than 50% of nominal wall. The rule now lists as 180-day conditions corrosion of and along a longitudinal seam weld, and metal loss greater than 50% that can affect a girth weld.

Other conditions: Paragraph (h) also listed examples of other conditions an operator would need to schedule for evaluation and repair. API recommended we eliminate this paragraph as they contended it is unworkable and unenforceable. Many of the listed conditions, according to API, are not pipeline conditions but describe characteristics of the conditions as they might appear in raw inspection data. API argued that this paragraph oversimplifies the task of using past data in evaluations.

Tosco also commented that the listed conditions seem to relate to an assessment using internal inspection tools, and conditions identified by other means of assessment (e.g., direct assessment) might not be addressed if this list were considered exhaustive.

Enron commented that because the list of other conditions contain vague descriptions (e.g., over a large area, abrupt in nature, reflect a change, near casings), compliance with and enforcement of these requirements will be arbitrary, inconsistent and result in numerous disagreements between operators and regulators. As an example, Enron explained that a strict interpretation of the requirement requiring an operator to evaluate data that reflect changes since the last internal inspection, could include any change, no matter how small, or even one indicating an improvement. Enron argued for us to allow operators a reasonable degree of latitude in making decisions regarding what conditions must be evaluated, and requested we provide guidance in the rule on this latitude and not develop it through enforcement and interpretation. Finally, Enron maintained the repair requirements are likely to result in differing interpretations by different regulatory agencies.

Response:

The paragraph listing other conditions is not intended as an exhaustive list, but simply a list of some of the conditions an operator was to address in its schedule. We wrote paragraph (h), as well as other provisions of section 195.452, to include performance-based and, when necessary, prescriptive language. The rule tries to balance the need of an operator for flexibility with the need for clear and enforceable regulations.

Although we strive for clarity in a regulation, language is an imprecise instrument and is invariably subject to different interpretations. We face this challenge in every rulemaking, yet we enforce the regulations with a modicum of difficulty. Nonetheless, in response to the comments, we modified the list of other conditions to give better descriptions of certain conditions an operator should address, and we relocated the list to Appendix C. This list will now offer guidance to operators on conditions they should be prepared to evaluate and remediate. An operator will now be required to evaluate and remediate conditions other than those listed as immediate repair, 60-day, and 180-day conditions, and in so doing to consider the guidance provided in Appendix C.

Again, we want to emphasize that the conditions listed as immediate repair, 60 day, and 180-day are not an exclusive list of conditions an operator will be required to evaluate and remediate. These are simply some of the conditions that may show up. The argument that because a condition was not listed in paragraph (h) or in the Appendix C guidance and so an operator did not know it was required to evaluate and remediate the condition, will never be accepted.

Comments on other provisions in the final rule:

The Integrity Management Rule issued on December 1, 2000, was a final rule. We only sought comment on the repair provisions in paragraph (h) due to the substantive changes made from those initially proposed. All other provisions of the rule were previously subject to notice and comment. Therefore, we will not address comments aimed at other provisions in the rule, in this document.

Paragraph (h) Requirements

Paragraph (h) of § 195.452 requires an operator to take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. Addressing all conditions means an operator must evaluate all anomalous conditions and remediate those which could reduce a pipeline's integrity. The actions an operator may take to remediate a condition include a range of mitigative and other actions, including repair. However, the action taken must be adequate to ensure the condition is unlikely to present a long-term threat to the integrity of the pipeline.

The time frames for evaluating and remediating certain conditions begin when the condition is discovered. Discovery of a condition occurs when an operator has adequate information to determine a condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make the determination that a condition presents a potential threat to the integrity of the pipeline. Thus, an operator has flexibility determining when it has sufficient information for discovery. However, the discovery process will end 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impracticable.

Discovery triggers the time frames for remediating a condition. An operator must have a schedule providing time frames for evaluating and completing remedial action on a condition.

For most conditions, it is left to each operator to determine how to prioritize the conditions for evaluation and remediation. An operator must be able to justify its prioritization. The rule provides the time frames in which an operator must complete repair or remediation of certain conditions. These are listed as immediate repair conditions, 60-day conditions and 180-day conditions. Of course, the rule cannot identify all conditions an operator will have to evaluate and remediate. A condition an operator discovers may qualify as an immediate repair, 60-day or 180-day condition, even though it is not listed in the rule. The rule simply provides common examples of such conditions.

The rule further provides that an operator is to include in its schedule, conditions other than those listed. Example of some conditions that could show up during an integrity assessment are provided in the Appendix C guidance. The list in the Appendix is not an exhaustive list.

An operator may deviate from the scheduled time frames for remediation of a condition, if the operator justifies the reasons why it cannot meet the schedule and the changed schedule will not jeopardize public safety or environmental protection. An operator's justification for a deviation would be one of the records the operator is required to maintain for inspection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. The operator would be required to provide RSPA/OPS notice by mail or facsimile.

Corrections to Section 195.452

The rule allowed two limited exceptions for when an operator could seek a variance from the five-year re-assessment intervals. One exception (paragraph (j)(4)(i)) is if an operator can justify, on an engineering basis, for a longer assessment interval. Among other requirements, an operator is to support the justification with the use of other technology that provides an understanding of the line pipe equivalent to that provided by the other allowable assessment methods. However, instead of referencing the assessment methods listed in paragraph (j)(5), the rule incorrectly referenced (j)(2), the paragraph addressing the periodic evaluation. We corrected the reference.

The second exception (paragraph (j)(4)(ii)) allows a variance because of unavailable sophisticated technology. For this exception an operator is to notify OPS 180 days before the end of the five-year interval. However, the rule further provided that an operator would then have to complete the assessment within 180 days. This requirement was incorrectly included and we deleted it. If an operator has to complete the re-assessment within 180 days of its 180-day notice, the operator would be completing the re-assessment within the five-year period. Therefore, with this requirement the exception allowing an extension is illusory. We deleted the requirement and instead, now specify that with its notice, an operator is to provide an estimate of when it will complete the re-assessment.

Advance notice to OPS is required before an operator conducts a continual integrity assessment using alternative technology. Paragraph (j) (5) (iii) of the final rule gave this period as 60 days. This was incorrect. The advance notification period should be 90 days, to be consistent with the advance notification period required when an operator uses alternative technology for the baseline assessment. We corrected the time period.

In paragraph (l), we inadvertently left out the number (1) before the first paragraph. We corrected this oversight.

We also corrected the grammar in several places in the Appendix C guidance.

Clarifications and Non-Substantive Revisions to Section 195.452

In paragraph (a) we clarified that the rule applies to any operator who owns or operates 500 or more miles of hazardous liquid or carbon dioxide pipeline. When we wrote the paragraph describing which operators need comply with the rule, we intended for the phrase "hazardous liquid" to include carbon dioxide pipelines. However, we have since realized that because of how hazardous liquid and carbon dioxide are used in other pipeline safety regulations, there may be confusion about whether carbon dioxide lines are included. By changing the language to "hazardous liquid or carbon dioxide," we eliminate any confusion about which operators are to comply.

In paragraphs (c)(1)(i) and (j)(5), questions were raised about the listed methods an operator is allowed to use for an integrity assessment. The questions concerned the application of the methods to low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure. We revised these paragraphs to make clear that the listed assessment methods apply to these types of pipe. Although for these types of pipe, an operator must choose methods that have certain capabilities, and the methods are to be from those listed in the rule.

In paragraph (j)(2) we clarified that the evaluation of assessment results include results from the baseline or periodic integrity assessments. Although an operator may have performed a previous internal inspection, unless the operator uses that as its baseline assessment the operator would not have had to maintain those records because the pipeline safety regulations did not require an internal inspection. This clarification should avoid any disagreement about which integrity assessment records an operator will need for its periodic evaluations.

In paragraph (j)(4)(i), we clarified the language about the requirements for the justification for a variance from the 5-year re-assessment interval for engineering reasons and the requirements for notification to OPS.

Due to changes we made to the terminology in paragraph (h), we revised several other paragraphs of the rule and Appendix C to be consistent with those changes. Affected paragraphs in § 195.452 are (f)(4) and (j)(2), and in Appendix C, VI (16) and VI(18).

We added a new paragraph (paragraph m) to the rule to clarify that the required notification must be sent to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington DC 20590, or to the facsimile number (202) 366–7128. Notification is required when an operator cannot meet its schedule for evaluating and remediating anomalous conditions; uses alternative technology for an integrity assessment; or seeks a variance from the five-year continual assessment interval.

In Appendix C, which contains guidance material for § 195.452, we added a section on conditions other than those listed in paragraph (h), which an operator could find from an integrity assessment and an operator should consider in its schedule for evaluation and remediation. We initially listed these conditions in paragraph (h) but decided they more appropriately fit into the Appendix C guidance. This guidance does not list every possible condition that could arise on a pipeline and an operator should evaluate. We also revised the introductory paragraph to reference the new section.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

This rulemaking action is not considered a significant regulatory action under section 3(f) of Executive Order (58 FR 51735; October 4, 1993). Therefore, the Office of Management and Budget did not review this rulemaking document.

We sought public comment on any additional financial burden that the repair requirements would have on the hazardous liquid pipeline industry. A supplemental report to the regulatory evaluation to address this issue is placed in the docket. The seven members present at the August 13, 2001, Technical Hazardous Pipeline Safety Standards committee meeting voted unanimously to accept the supplement to the regulatory evaluation. Below is a summary of their supplemental report.

Treatment of Repairs in Cost-Benefit Analysis for the Integrity Management Rule

The final regulatory evaluation supporting the integrity management rule did not estimate the costs associated with repairs to pipe that may occur as a result of the rule. The evaluation instead focused on the costs associated with the planning and integrity assessments required by the rule. The reasons for not evaluating repair costs were:

1. The pipeline safety regulations have always required an operator to repair problems found on its hazardous liquid or carbon dioxide pipelines. (49 CFR 195.401(b)). The primary changes made by the Integrity Management rule were to establish a systematized assessment and evaluation process that

Federal Register / Vol. 67, No. 9 / Monday, January 14, 2002 / Rules and Regulations 1659

would cause operators to better identify conditions on their pipelines requiring repair. Thus, the additional effort required of operators by the rule is in the planning and assessment process, the costs of which were considered in the regulatory evaluation. Repair of a problem, once it is known, was not a new requirement and was not evaluated because of the assumption that additional costs would not be incurred.

2. The repair criteria in paragraph (h) of the final rule (65 FR 75378; December 1, 2000) were changed from those published with the proposed rule. Accordingly, public comments were solicited regarding the repair criteria. RSPA received comments from six organizations (one trade association, one engineering company, three operators directly affected by the rule, and one operator not directly affected by the rulemaking). None commented on the lack of specific reference to repair costs in the regulatory evaluation.

3. Some commenters identified criteria they believed would require unnecessary excavation and evaluation of minor pipeline anomalies that would not affect a pipeline's integrity. We made changes to the provisions in paragraph (h) in response to these comments. These changes clarify the types of conditions an operator must evaluate and remediate so the focus will be on those conditions that are most likely to affect pipeline integrity. Moreover, the remediation requirements allow an operator flexibility in the action it takes to address a condition that poses a threat to the integrity of its pipeline. These provisions are consistent with the existing requirements in section 195.401(b), and add no additional costs.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), RSPA must consider whether a rulemaking would have a significant impact on a substantial number of small entities. This rulemaking was designed to impact only those operators that own or operate 500 or more miles of hazardous liquid or carbon dioxide pipeline. Because of this limitation on pipeline mileage, only 66 hazardous liquid pipeline operators (large national energy companies) covering 86.7% of regulated liquid transmission lines are impacted by this final rule. Based on this, and the evidence discussed above, I certify that paragraph (h) in the final rule addressing the remedial actions an operator is required to take to address integrity concerns on its pipeline will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

The pipeline integrity management rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507 (d)), the Department of Transportation submitted a copy of the Paperwork Reduction Act Analysis to the Office of Management and Budget for its review. The information collection was reviewed and approved by the Office of Management and Budget. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas." The remediation requirements in paragraph (h) of the rule will not add any additional paperwork on hazardous liquid or carbon dioxide pipeline operators as repair requirements must already comply with 49 CFR 195.401(b). This was discussed above in the Regulatory Evaluation section. Therefore, no additional paperwork reduction analysis is necessary.

Executive Order 13084

The remediation provisions of the integrity management final rule were analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments.") Because these provisions, as well as the other provisions of the final rule, do not significantly or uniquely affect the communities of the Indian tribal governments and do not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

The final rule provisions in paragraph (h) were analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This final rule does not adopt 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 States and local governments; or

(3) preempts state law.

Nonetheless, State public safety representatives were involved throughout the development of the hazardous liquid integrity management rule.

Executive Order 13211

This rulemaking is not a "significant energy action" within the meaning of Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use"). 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.

Unfunded Mandates

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

National Environmental Policy Act

In accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. Section 4332), the Council on Environmental Quality regulations (40 CFR Sections 1500–1508), and DOT Order 5610.1D, we prepared an Environmental Assessment (EA) that analyzed the environmental impacts of the rulemaking addressing integrity management programs for operators owning or operating 500 or more miles of hazardous liquid or carbon dioxide pipeline. In the EA we determined that the rule would not significantly affect the quality of the human environment. The EA and the Finding of No Significant Impact are available in Docket No. RSPA–00–6355. That EA considered the requirements in section 195.452 (h) concerning repairs an operator would have to make to its pipeline following an integrity assessment.

We reviewed the EA in light of the changes we have made to § 195.452 (h), and did not find that any of the changes affected our finding about the environmental impacts of the rule.

List of Subjects in 49 CFR Part 195

Carbon dioxide, High consequence areas, Incorporation by reference, Integrity assurance, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

For the reasons set forth in the Preamble, RSPA is amending part 195 of title 49 of the Code of Federal Regulations 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.

Subpart F—Operation and Maintenance

* * * * *

Pipeline Integrity Management

2. Section 195.452(a) is revised to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which operators must comply?* This section applies to each operator who owns or operates a total of 500 or more miles of hazardous liquid or carbon dioxide pipeline subject to this part.

* * * * *

3. Section 195.452 is amended by revising paragraph (c)(1)(i) introductory text and paragraph (c)(1)(i)(C) to read as follows:

(c) * * *

(1) * * *

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

* * * * *

(C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

* * * * *

4. Section 195.452(f) (4) is revised to read as follows:

(f) * * *

(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

* * * * *

5. Section 195.452 (h) is revised to read as follows:

(h) *What actions must an operator take to address integrity issues?*

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair.

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

(3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.

(4) *Special requirements for scheduling remediation.* (i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see § 195.3). An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR–3–805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *60 day conditions.* Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

(iii) *180-day conditions.* Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of

Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR–3–805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iv) *Other conditions.* In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

* * * * *

6. § 195.452 is amended by revising the last sentence of paragraph (j)(2), revising paragraphs (j)(4), (j)(5) introductory text and (j)(5)(iii), and removing paragraph (j)(6)to read as follows:

(j) * * *

(2) *Evaluation.* * * * . The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) * * *

(4) *Variance from the 5-year intervals in limited situations.*(i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

(ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address specified in paragraph (m) of this section.

(5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(i) * * *

(ii) * * *

(iii) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

7. Paragraph (k)(1) is redesignated as paragraph (l); paragraph designation "(1)" is added after the heading; and paragraph (k)(2) is redesignated as paragraph (l)(2).

* * * * *

8. A new paragraph (m) is added to § 195.452 to read as follows:

(m) *Where does an operator send a notification?* An operator must send any notification required by this section to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington DC 20590, or to the facsimile number (202) 366–7128.

9. Appendix C is amended by revising the title, adding paragraph (7) in the introductory text, revising paragraphs (7), (8), and (9) of section I.B., removing paragraph (18) from section VI and renumbering paragraphs (19) through (23) as (18) through (22), revising paragraphs (16) and newly designated (18) of section VI, and adding a new Section VII to read as follows:

APPENDIX C TO PART 195—GUIDANCE FOR IMPLEMENTATION OF AN INTEGRITY MANAGEMENT PROGRAM

* * * * *

(7) Types of conditions that an integrity assessment may identify that an operator should include in its required schedule for evaluation and remediation.

I. * * *

B. * * *

(7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.

(8) The hydraulic gradient of the pipeline.

(9) The diameter of the pipeline, the potential release volume, and the distance between the isolation points.

* * * * *

VI. * * *

(16) integrity assessment results and anomalies found, process for evaluating and remediating anomalies, criteria for remedial actions and actions taken to evaluate and remediate the anomalies;

* * * * *

(18) schedule for evaluation and remediation of anomalies, justification to support deviation from required remediation times;

* * * * *

VII. Conditions that may impair a pipeline's integrity.

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. The following are some examples of conditions that an operator should schedule for evaluation and remediation.

A. Any change since the previous assessment.

B. Mechanical damage that is located on the top side of the pipe.

C. An anomaly abrupt in nature.

D. An anomaly longitudinal in orientation.

E. An anomaly over a large area.

F. An anomaly located in or near a casing, a crossing of another pipeline, or an area with suspect cathodic protection.

Issued in Washington, DC, on December 21, 2001.

Ellen G. Engleman,

Administrator.

[FR Doc. 02–267 Filed 1–11–02; 8:45 am]

BILLING CODE 4910–60–P

Implementing Integrity Management - Final Rule (as amended)
January 16, 2002

Integrity Management for Hazardous Liquid Pipeline Operators

High Consequence Areas

§ 195.450 Definitions.

The following definitions apply to this section and § 195.452:

Emergency flow restricting device or *EFRD* means a check valve or remote control valve as follows:

(1) *Check valve* means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction.

(2) *Remote control valve* or *RCV* means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

High consequence area means:

(1) *A commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;

(2) *A high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

(3) An *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

(4) An *unusually sensitive area*, as defined in § 195.6.

Pipeline Integrity Management

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002
Category 2	February 18, 2003
Category 3	1 year after the date the pipeline begins operation

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	December 31, 2001
Category 2	November 18, 2002
Category 3	Date the pipeline begins operation

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that-

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless-

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

(c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan:

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(B) Pressure test conducted in accordance with subpart E of this part; or

(C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(ii) A schedule for completing the integrity assessment;

(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows: (1) *Time periods.* Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004
Category 2	February 17, 2009	August 16, 2005
Category 3	Date the pipeline begins operation	Not applicable

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows:

Pipeline	Date
Category 1	January 1, 1996
Category 2	December 18, 2006

(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in § 195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;

(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;

(iii) Leak history, repair history and cathodic protection history;

(iv) Product transported;

(v) Operating stress level;

(vi) Existing or projected activities in the area;

(vii) Local environmental factors that could affect the pipeline (*e.g.*, corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and

(ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors.

(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(1) A process for identifying which pipeline segments could affect a high consequence area;

(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

(7) Methods to measure the program's effectiveness (see paragraph (k) of this section);

(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the entire pipeline and integrity of the entire pipeline and the consequences of a failure. This information includes:

(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;

(2) Data gathered through the integrity assessment required under this section;

(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

(h) *What actions must an operator take to address integrity issues?*
(1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair.

(2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

(3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.

(4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see § 195.3). An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR- 3- 805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *60-day conditions.* Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

(iii) *180-day conditions*. Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR- 3- 805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iv) *Other conditions*. In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*

(1) *General requirements*. An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(2) *Risk analysis criteria*. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(3) *Leak detection*. An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

(4) *Emergency Flow Restricting Devices (EFRD)*. If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors- the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and

the high consequence area, and benefits expected by reducing the spill size.

(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (1) *General*. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

(2) *Evaluation*. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) *Assessment intervals*. An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

(4) *Variance from the 5-year intervals in limited situations*-(i) *Engineering basis*. An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

(ii) *Unavailable technology*. An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address specified in paragraph (m) of this section.

(5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(ii) Pressure test conducted in accordance with subpart E of this part; or

(iii) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

(l) *What records must be kept?* (1) An operator must maintain for review during an inspection:

(i) A written integrity management program in accordance with paragraph (b) of this section.

(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

(2) See Appendix C of this part for examples of records an operator would be required to keep.

(m) *Where does an operator send a notification?* An operator must send any notification required by this section to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington DC 20590, or to the facsimile number (202) 366-7128.

Appendix C to Part 195-Guidance for Implementation of an Integrity Management Program

This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule in §§ 195.450 and 195.452.

Guidance is provided on:

(1) Information an operator may use to identify a high consequence area and factors an operator ca

use to consider the potential impacts of a release on an area;

(2) Risk factors an operator can use to determine an integrity assessment schedule;

(3) Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a pipeline segment falls into a high, medium or low risk category;

(4) Types of internal inspection tools an operator could use to find pipeline anomalies;

(5) Measures an operator could use to measure an integrity management program's performance; and

(6) Types of records an operator will have to maintain.

(7) Types of conditions that an integrity assessment may identify that an operator should include in its required schedule for evaluation and remediation.

I. Identifying a high consequence area and factors for considering a pipeline segment's potential impact on a high consequence area.

A. The rule defines a High Consequence Area as a high population area, an other populated area, an unusually sensitive area, or a commercially navigable waterway. The Office of Pipeline Safety (OPS) will map these areas on the National Pipeline Mapping System (NPMS). An operator, member of the public, or other government agency may view and download the data from the NPMS home page http://www.npms.rspa.dot.gov. OPS will maintain the NPMS and update it periodically. However, it is an operator's responsibility to ensure that it has identified all high consequence areas that could be affected by a pipeline segment. An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to § 195.452(d)(3).) For more information to help in identifying high consequence areas, an operator may refer to:

(1) Digital Data on populated areas available on U.S. Census Bureau maps.

(2) Geographic Database on the commercial navigable waterways available on http://www.bts.gov/gis/ntatlas/networks.html.

(3) The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at http://www.bts.gov/gis/ntatlas/networks.html.

B. The rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. (See §§ 195.452 (f) and (i).) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area. The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee. The following list provides guidance to an operator on both the mandatory and additional factors:

(1) Terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.

(2) Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.

(3) Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.

(4) Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.

(5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids becomes gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.

(6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.

(7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.

(8) The hydraulic gradient of the pipeline.

(9) The diameter of the pipeline, the potential release volume, and the distance between the isolation points.

(10) Potential physical pathways between the pipeline and the high consequence area.

(11) Response capability (time to respond, nature of response).

(12) Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

II. Risk factors for establishing frequency of assessment.

A. By assigning weights or values to the risk factors, and using the risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed. This list provides some guidance on some of the risk factors to consider (see § 195.452(e)). An operator should also develop factors specific to each pipeline segment it is assessing, including:

(1) Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.

(2) Results from previous testing/inspection. (See § 195.452(h).)

(3) Leak History. (See leak history risk table.)

(4) Known corrosion or condition of pipeline. (See § 195.452(g).)

(5) Cathodic protection history.

(6) Type and quality of pipe coating (disbonded coating results in corrosion).

(7) Age of pipe (older pipe shows more corrosion-may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)

(8) Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment) (see Product transported risk table.)

(9) Pipe wall thickness (thicker walls give a better safety margin)

(10) Size of pipe (higher volume release if the pipe ruptures).

(11) Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement-Alaska); geologic (landslides or subsidence).

(12) Security of throughput (effects on customers if there is failure requiring shutdown).

(13) Time since the last internal inspection/pressure testing.

(14) With respect to previously discovered defects/anomalies, the type, growth rate, and size.

(15) Operating stress levels in the pipeline.

(16) Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).

(17) Physical support of the segment such as by a cable suspension bridge.

(18) Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

B. Example: This example illustrates a hypothetical model used to establish an integrity assessment schedule for a hypothetical pipeline segment. After we determine the risk factors applicable to the pipeline segment, we then assign values or numbers to each factor, such as, high (5), moderate (3), or low (1). We can determine an overall risk classification (A, B, C) for the segment using the risk tables and a sliding scale (values 5 to 1) for risk factors for which tables are not provided. We would classify a segment as C if it fell above 2/3 of maximum value (highest overall risk value for any one segment when compared with other segments of a pipeline), a segment as B if it fell between 1/3 to 2/3 of maximum value, and the remaining segments as A.

i. For the baseline assessment schedule, we would plan to assess 50% of all pipeline segments covered by the rule, beginning with the highest risk segments, within the first 3 1/2 years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two (2) years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk segments no later than year five (5).

ii. For our hypothetical pipeline segment, we have chosen the following risk factors and obtained risk factor values from the appropriate table. The values assigned to the risk factors are for illustration only.

Age of pipeline: assume 30 years old (refer to "Age of Pipeline" risk table) - Risk Value = 5

Pressure tested: tested once during construction - Risk Value=5

Coated: (yes/no)-yes

Coating Condition: Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)- Risk Value=5

Cathodically Protected: (yes/no)-yes - Risk Value=1

Date cathodic protection installed: five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline's construction is generally considered low risk.) - Risk Value=3

Close interval survey: (yes/no)-no-Risk Value =5

Internal Inspection tool used: (yes/no) - yes. Date of pig run? In last five years - Risk Value=1

Anomalies found: (yes/no)-yes, but do not pose an immediate safety risk or environmental hazard - Risk Value=3

Leak History: yes, one spill in last 10 years. (refer to "Leak History" risk table) - Risk Value=2

Product transported: Diesel fuel. Product low risk. (refer to "Product" risk table) - Risk Value=1

Pipe size: 16 inches. Size presents moderate risk (refer to "Line Size" risk table) - Risk Value=3

iii. Overall risk value for this hypothetical segment of pipe is 34. Assume we have two other pipeline segments for which we conduct similar risk rankings. The second pipeline segment has an overall risk value of 20, and the third segment, 11. For the baseline assessment we would establish a schedule where we assess the first segment (highest risk segment) within two years, the second segment within five years and the third segment within seven years. Similarly, for the continuing integrity assessment, we could establish an assessment schedule where we assess the highest risk segment no later than the second year, the second segment no later than the third year, and the third segment no later than the fifth year.

III. Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

Leak History

Safety Risk Indicator	Leak history (Time-dependent defects) [1]
High	> 3 Spills in last 10 years
Low	< 3 Spills in last 10 years

[1] Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

Line Size or Volume Transported

Safety Risk Indicator	Line Size
High	≥ 18"
Moderate...	10"-16" nominal diameters
Low	≤ 8" nominal diameter

Age of Pipeline

Safety Risk Indicator	Age Pipeline condition dependent) [1]
High	> 25
Low	< 25

[1] Depends on pipeline's coating & corrosion condition, and steel quality, toughness, welding.

Product Transported

Safety risk indicator	Considerations [1]	Product examples
High	(Highly volatile and flammable)	(Propane, butane, Natural Gas Liquid (NGL), ammonia).
	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils).
Medium.......	Flammable-flashpoint <100F	(Gasoline, JP4, low flashpoint crude oils).
Low	Non-flammable-flashpoint 100+F	(Diesel, fuel oil, kerosene, JP5, most crude oils).

[1] The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

IV. Types of internal inspection tools to use.

An operator should consider at least two types of internal inspection tools for the integrity assessment from the following list. The type of tool or tools an operator selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

(1) Geometry Internal inspection tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;

(2) Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion.

(3) Crack Detection Tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

V. Methods to measure performance.

A. *General*. (1) This guidance is to help an operator establish measures to evaluate the effectiveness of its integrity management program. The performance measures required will depend on the details of each integrity management program and will be based on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment.

(2) An operator should select a set of measurements to judge how well its program is performing. An operator's objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. A typical integrity management program will be an ongoing program and it may contain many elements. Therefore, several performance measure are likely to be needed to measure the effectiveness of an ongoing program.

B. *Performance measures*. These measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories:

(1) Selected Activity Measures-Measures that monitor the surveillance and preventive activities the operator has implemented. These measure indicate how well an operator is implementing the various elements of its integrity management program.

(2) Deterioration Measures-Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

(3) Failure Measures-Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

C. *Internal vs. External Comparisons*. These comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the operator's other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operators' pipeline segments.

(1) Internal-Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area.

(2) External-Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

D. Examples. Some examples of performance measures an operator could use include-

(1) A performance measurement goal to reduce the total volume from unintended releases by -% (percent to be determined by operator) with an ultimate goal of zero.

(2) A performance measurement goal to reduce the total number of unintended releases (based on a threshold of 5 gallons) by ll -% (percent to be determined by operator) with an ultimate goal of zero.

(3) A performance measurement goal to document the percentage of integrity management activities completed during the calendar year.

(4) A performance measurement goal to track and evaluate the effectiveness of the operator's community outreach activities.

(5) A narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to an operator's integrity management program prepared periodically.

(6) A performance measure based on internal audits of the operator's pipeline system per 49 CFR Part 195.

(7) A performance measure based on external audits of the operator's pipeline system per 49 CFR Part 195.

(8) A performance measure based on operational events (for example: relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.

(9) A performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high risk items.

(10) A performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

VI. Examples of types of records an operator must maintain.

The rule requires an operator to maintain certain records. (See §195.452(l)). This section provides examples of some records that an operator would have to maintain for inspection to comply with the requirement. This is not an exhaustive list.

(1) a process for identifying which pipelines could affect a high consequence area and a document identifying all pipeline segments that could affect a high consequence area;

(2) a plan for baseline assessment of the line pipe that includes each required plan element;

(3) modifications to the baseline plan and reasons for the modification;

(4) use of and support for an alternative practice;

(5) a framework addressing each required element of the integrity management program, updates and changes to the initial framework and eventual program;

(6) a process for identifying a new high consequence area and incorporating it into the baseline plan, particularly, a process for identifying population changes around a pipeline segment;

(7) an explanation of methods selected to assess the integrity of line pipe;

(8) a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data;

(9) the process and risk factors for determining the baseline assessment interval;

(10) results of the baseline integrity assessment;

(11) the process used for continual evaluation, and risk factors used for determining the frequency of evaluation;

(12) process for integrating and analyzing information about the integrity of a pipeline, information and data used for the information analysis;

(13) results of the information analyses and periodic evaluations;

(14) the process and risk factors for establishing continual re-assessment intervals;

(15) justification to support any variance from the required re-assessment intervals;

(16) integrity assessment results and anomalies found, process for evaluating and remediating anomalies, criteria for remedial actions and actions taken to evaluate and remediate the anomalies;

(17) other remedial actions planned or taken;

(18) schedule for evaluation and remediation of anomalies, justification to support deviation from required remediation times;

(19) risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;

(20) criteria for determining EFRD installation;

(21) criteria for evaluating and modifying leak detection capability;

(22) methods used to measure the program's effectiveness.

VII. Conditions that may impair a pipeline's integrity.

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. The following are some examples of conditions that an operator should schedule for evaluation and remediation.

A. Any change since the previous assessment.

B. Mechanical damage that is located on the top side of the pipe.

C. An anomaly abrupt in nature.

D. An anomaly longitudinal in orientation.

E. An anomaly over a large area.

F. An anomaly located in or near a casing, a crossing of another pipeline, or an area with suspect cathodic protection.