

DEPARTMENT OF TRANSPORTATION**Research and Special Programs
Administration****49 CFR Part 195****[Docket No. RSPA-99-6355; Amendment
195-70]****RIN 2137-AD45****Pipeline Safety: Pipeline Integrity
Management in High Consequence
Areas (Hazardous Liquid Operators
With 500 or More Miles of Pipeline)****AGENCY:** Research and Special Programs
Administration (RSPA), DOT.**ACTION:** Final rule.

SUMMARY: This final rule specifies regulations to assess, evaluate, repair and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. OPS is requiring that an operator develop and follow an integrity management program that provides for continually assessing the integrity of all pipeline segments that could affect these high consequence areas, through internal inspection, pressure testing, or other equally effective assessment means. The program must also provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the assessment and evaluation, and ensuring additional protection to the segments and the high consequence areas through preventive and mitigative measures.

Through this required program, hazardous liquid operators will comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. This includes analyzing information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The final rule requires an operator to take prompt action to address the integrity issues raised by the assessment

and analysis. This means an operator must evaluate all defects and repair those could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the defects for evaluation and repair, including time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also provide additional protection for these pipeline segments through other remedial actions, and preventive and mitigative measures.

DATES: Effective Date: This final rule takes effect March 31, 2001.

Compliance Dates: An operator must complete an identification of all pipeline segments that could affect a high consequence area no later than December 31, 2001. An operator must develop a written integrity management program no later than March 31, 2002.

Comment Date: Interested persons are invited to submit comment on the provisions of the rule concerning actions an operator must take to address integrity issues on the pipeline (§ 195.452(h)) by March 31, 2001. At the end of the comment period, we will publish a document modifying these remedial action provisions or a document stating that the provisions will remain unchanged.

ADDRESSES: Comments limited to the provisions on actions an operator must take to address pipeline integrity issues (§ 195.452(h)) must be sent to the Dockets Facility, U.S. Department of Transportation, Room PL-401, 400 Seventh Street, SW, Washington, DC 20590-0001. It is open from 10:00 a.m. to 5:00 p.m., Monday through Friday, except federal holidays. You also may submit written comments to the docket electronically. To do so, log on to the following Internet Web address: <http://dms.dot.gov>. Click on "Help & Information" for instructions on how to file a document electronically. All written comments should identify the docket number stated in the heading of this rule.

FOR FURTHER INFORMATION CONTACT: Mike Israni, (202) 366-4571, or by e-mail: mike.israni@rspa.dot.gov, regarding the subject matter of this final 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 programs may be obtained by accessing OPS's Internet home page at <http://ops.dot.gov>.

SUPPLEMENTARY INFORMATION:

Background*Notice of Proposed Rulemaking*

On April 24, 2000, OPS published a notice of proposed rulemaking (65 FR 21695) that proposed pipeline integrity management program requirements for hazardous liquid operators that operated 500 or more miles of pipeline. The proposed requirements were to apply to hazardous liquid pipelines that could affect areas we proposed as high consequence areas—populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways.

OPS issued the proposal after a public meeting that OPS hosted on November 18 & 19, 1999, to gather information on current pipeline assessment methods and integrity management programs. OPS had also established an electronic public discussion forum to gather further information. Comments and information gathered from these forums were used in developing the proposed rule for larger hazardous liquid operations. The proposed rule was the first in a series of rulemakings that will require all regulated pipeline operators to have integrity management programs.

The notice proposed that a hazardous liquid operator develop and follow an integrity management program. Among the proposed required elements of a program were—

- Baseline assessment of all pipelines that could affect a high consequence area. The integrity of these pipelines was to be assessed by internal inspection, pressure test, or equivalent alternative new technology. The assessment had to be completed in seven years, with 50% of the pipeline mileage done in three and one-half years.

- Continual assessment of all pipelines that could affect a high consequence area. An operator would have to continue to assess, at intervals not to exceed ten-years, and periodically evaluate the integrity of the pipelines.

- Data integration. An operator would have to integrate all information about the pipeline from diverse sources to analyze the entire range of threats to a pipeline's integrity.

- Prompt remedial action. An operator would have to take prompt action to address all integrity issues raised by the integrity assessment and data integration analysis.

- Preventive and mitigative measures. An operator would have to evaluate the need for additional measures to prevent and mitigate pipeline failures, such as installing emergency flow restricting devices (EFRDs) and establishing or

modifying systems that monitor pressure and detect leaks.

- Performance measures to measure the effectiveness of the program.

The proposed rule permitted two options in establishing baseline and continual assessment schedules. An operator choosing the first option would have to base the schedule on specified risk factors. With the second option, an operator would base the schedule on risk factors the operator considered essential in risk or consequence evaluation.

The NPRM explained in great detail the background of the proposed rule for the integrity management program (65 FR 21695; April 24, 2000).

In the NPRM, we said that we intended to apply integrity management program requirements to all regulated pipeline operators but that we would implement the requirements in several steps; when we were done, all regulated operators would be required to have an integrity management program. We explained that because natural gas and hazardous liquid have different physical properties, pose different risks, and the configuration of the systems differ, and because we needed to gather more information about smaller liquid operations, we were beginning the series of integrity management program proposals with hazardous liquid operators operating 500 or more miles of pipeline. We further stated that proposed regulatory requirements for the other operators would soon follow.

The proposed rulemaking was the culmination of experience gained from inspections, accident investigations and risk management and system integrity initiatives. This experience was the foundation for proposing a rulemaking that addressed in a comprehensive manner NTSB recommendations, Congressional mandates and pipeline safety and environmental issues raised over the years. To recap the history of the rulemaking—

- The rulemaking addressed several recommendations NTSB made to OPS concerning pipeline safety.

(1) Require periodic testing and inspection to identify corrosion and other time-dependent damages.

(2) Establish criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

(3) Determine hazards to public safety from electric resistance welded (ERW) pipe and establish standards for leak detection, and expedite requirements for installing automatic or remote-operated mainline valves on high-pressure lines in urban and environmentally sensitive

areas to provide for rapid shutdown of failed pipeline segments.

- Our analyses of several pipeline ruptures in Bellingham, Washington; Simpsonville, South Carolina; Reston, Virginia; and Edison, New Jersey, brought to light the need for operators to address the potential interrelationship among failure causes and to implement coordinated risk control actions to supplement the protection of the regulations.

- The rulemaking also addressed several Congressional mandates to OPS concerning areas where the risk of a pipeline spill could have significant impact.

(1) 49 U.S.C. 60109(a)—prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas and for hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists, or are located in a high-density population area, or are located in an area unusually sensitive to environmental damage (USAs).

(2) 49 U.S.C. 60102(f)(2)—prescribe, if necessary, additional standards requiring the periodic inspection of pipelines in USAs and high-density population areas, and those crossing commercially navigable waterways, to include any circumstances when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline.

(3) 49 U.S.C. 60102(j)—survey and assess the effectiveness of emergency flow restricting devices (EFRDs) and other procedures, systems, and equipment used to detect and locate hazardous liquid pipeline ruptures, and to prescribe standards on the circumstances where an operator of a hazardous liquid pipeline facility must use an EFRD or such other procedure, system, or equipment.

Risk Management and Inspection Initiatives

The proposed rulemaking was also based on what we had learned about integrity management programs from our risk management and pipeline inspection activities, particularly the Risk Management Demonstration Program, the Systems Integrity Inspection (SII) Pilot Program and the new high impact format for inspections. (These programs and activities are discussed in greater detail in the NPRM (65 FR 21695).)

In the Risk Management Demonstration and Systems Integrity Inspection Pilot Programs, we studied and evaluated comprehensive and

integrated approaches to safety and environmental protection. These approaches incorporated operator- and pipeline-specific information and data to identify, assess, and address pipeline risks, in conjunction with compliance with existing pipeline safety regulations. From these programs, we also learned about the extent and variety of internal inspection and other diagnostic tools that hazardous liquid pipeline operators use in their integrity management programs.

OPS implemented a systems approach through a new high impact inspection format that evaluates pipeline systems as a whole rather than in small segments. We found that a system-wide approach is a more effective and, in most cases, more efficient means of evaluating pipeline integrity. As part of this approach, we have been evaluating how pipeline operators integrate information about their pipelines to determine the best means of addressing risk. This experience is helping us to develop detailed inspection guidelines to evaluate compliance with the requirements of this rule.

Advisory Committee Consideration

The Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) is the Federal advisory committee charged with responsibility for advising on the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed hazardous liquid pipeline safety standards. The 15 member committee has balanced membership with individuals having the requisite expertise who represent industry, government, and the general public.

We presented the proposed rule to the Technical Hazardous Liquid Pipeline Safety Standards Committee at its meeting on May 4, 2000. At the request of various committee members, who believed that they had not had sufficient time to review the proposed rule, which was published in April, 2000, formal consideration of the proposal was postponed to September. In preparation for this consideration, the draft cost-benefit analysis was mailed to the members on June 16, 2000 and the members were briefed on the proposed rule in a teleconference on August 24, 2000.

The committee began consideration of the proposed rule at a September 11, 2000 meeting (by teleconference) and completed consideration at a September 22, 2000 meeting (by teleconference). At the September 22 meeting, ten of the eleven participating THLPSSC members voted to accept the proposed rule provided several changes were made.

One member abstained from the general vote, but voted on the individual changes. These changes as well as other comments including minority views are described below. A more complete description can be found in the transcript of the committee's consideration of the proposed rule which is available in the docket.

Various committee members had earlier expressed concern about the quality of the cost-benefit analysis. Concerns expressed included the lack of clear articulation of the benefits and the failure to follow the framework for cost-benefit analysis developed for use in pipeline safety rulemaking. In response to these concerns, OPS committed to revise the cost-benefit analysis to be more consistent with the framework prior to publication of a final rule. Discussion of the issue at the September 22nd meeting indicated that members did not want to delay the issuance of a final rule, but that they believed that the quality of the cost-benefit analysis to be important. The committee voted unanimously that it could not conclude that the proposed rule is reasonable at this time until OPS completed a more meaningful cost-benefit analysis based on the framework. The committee recommended that this be done prior to issuance of the final rule.

In addition, the committee unanimously made the following recommendations for changes to the proposed rule:

- Add pipeline stress to the list of risk factors to be considered in determining the frequency of integrity assessment.
- Clarify OPS's responsibility to identify, generate, publish, and update maps of high consequence areas.
- Establish time requirements for completion of repairs following detection of the defects. The timing may be tiered.
 - Require leak detection capability.
 - Specify the date (for example, January 1995) for acceptability of data from previously conducted internal inspections. This date should be consistent with the proposed 5 year look-back.

With the exception of item 2 (responsibility for maps), RSPA has made changes to the final rule that address each of these recommendations. RSPA is addressing item 2 in this preamble, under the topic heading "Definition of High Consequence Areas—Identification", rather than in language of the rule. That section describes the process through which RSPA intends to make maps identifying high consequence areas available to the operators and the public.

In addition to the formal recommendations of the committee, individual committee members raised two issues about which there was general agreement. The first of these concerned the need to clarify the applicability of the rule to offshore areas. This issue is addressed under the topic heading "Applicability (Coverage) of the Rule." The second of these was the need to clarify the use of internal inspection to assess the integrity of pre-1970 electric resistance welded (ERW) pipe. The committee member was concerned that a footnote in the proposed rule would preclude internal inspection of this type of pipe. Accordingly, RSPA has modified the rule to address the issue. We discuss the rule modification later under the topic heading "Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria."

Prior to the meeting, one committee member had raised the issue of requirements for emergency flow restricting devices. RSPA had indicated that it was considering including criteria for requiring the use of such devices. After a brief discussion in the meeting, the member decided not to pursue a formal recommendation by the committee. As discussed later in the Preamble under the topic heading "Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices", RSPA has modified the rule's provisions concerning emergency flow restricting devices.

There was some discussion in the various meetings that indicated some concern about how RSPA would be able to enforce broad requirements for programs. Some committee members suggested the need for specific criteria that inspectors could apply in reviewing an operator's program. Although these discussions did not result in formal recommendations by the committee, RSPA has included additional specificity in the final rule that will aid in reviewing integrity management programs. In addition, enforceability is discussed elsewhere in this preamble.

The committee also discussed three other issues about which there was not general agreement. Four members of the committee believed that the final rule or a future modification should require leak detection systems and specify performance standards for those systems. The proposed rule did not propose to require or set standards for leak detection systems. (Current regulations require computational pipeline monitoring leak detection systems to comply with API 1130, the

industry consensus standard.) Industry members raised concerns about the scope of the current proposed rule and offered to brief the committee at a future meeting on the range of leak detection systems currently available. As noted above, the committee finally recommended by unanimous consent that the final rule require that pipelines affecting high consequence areas have the capability of detecting leaks. As explained later in the Preamble under the topic heading "Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices", we have revised the rule to address this recommendation.

A second area of discussion about which there was not agreement was a motion to reduce the time for completion of the initial baseline assessment from seven years to three years. RSPA's rationale for not reducing this time frame is discussed elsewhere in this preamble.

The third area was a motion to reduce the time interval for subsequent assessments from ten years to five years. The committee was evenly divided on this issue. As discussed elsewhere in this document under the heading "Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria", RSPA has decided to modify the time interval for integrity re-assessments subsequent to the baseline assessment.

Comments to NPRM

- We received comments from 36 sources in response to the NPRM:
- 2 Trade associations with members affected by this rulemaking
 - American Petroleum Institute (API)
 - American Water Works Association (AWWA)
 - 3 Trade associations with members not directly affected by this rulemaking
 - American Gas Association (AGA)
 - New York Gas Group
 - Interstate National Gas Association of America (INGAA)
 - 8 Individual liquid operators
 - Tosco Corporation
 - Chevron Pipe Line Company
 - BP Amoco
 - Colonial Pipeline Company
 - Koch Pipeline Company
 - Equilon Pipeline Company
 - Enbridge (U.S.) Inc. and Lakehead Pipe Line Partners
 - Dynegy Midstream Services
 - 4 Operators not directly affected by this rulemaking
 - The Peoples Gas Light and Coke Company (LDC and intrastate)

- Tennessee Gas Company (natural gas transmission)
 Enron Pipeline Group (natural gas transmission)
 Consumers Energy (natural gas transmission and distribution)
- 2 State agencies
 Lower Colorado River Authority (LCRA)
 State of Missouri—Department of Natural Resources
- 6 Advocacy groups
 Robert B. Rackleff, Friends of the Aquifer
 Pipeline Survivor's(sic) Association
 Environmental Defense
 National Pipeline Reform Coalition
 Fuel Safe Washington
 Harry S. Kottke and Delbert L. Moine, representing Ohio Pennsylvania Landowners Association (OPLA)
- 4 Federal agencies
 Environmental Protection Agency, Region III
 Environmental Protection Agency, Oil Program Center
 Department of Energy
 National Transportation Safety Board
- 2 Cities
 Austin, Texas
 Bellingham, Washington
- 3 Consultants/Contractors
 Batten and Associates
 Dr. Neb I. Uzelac
 SEFBO
- 2 Individuals
 U.S. Senator John Breaux
 Dene Miller Alden

General Comments

Virtually all commenters were supportive of the need for additional and stronger regulations in this area, and provided comments and suggestions focusing on specific details and language of the proposed rule. Commenters generally fell into one of two groups: those that thought the general structure of the proposed rule was adequate and provided the appropriate balance between prescriptive requirements and pipeline-specific analysis, and those that believed the proposed rule was not sufficiently strong, broad enough in scope, or specific.

All commenters were positive about the need for additional communication among industry, public safety officials, regulators, and the public concerning pipeline risks. We have decided to address the topic of public communication and interaction in a subsequent related rulemaking. We will address these comments in more detail in that rulemaking.

The trade associations and operators that are not directly affected by this rulemaking provided comments in

anticipation of future integrity management program regulations that would affect them. We will use these comments when preparing the proposed rulemakings for the other operators.

We have summarized the comments we received under the following topic areas:

1. Clarity and Specificity in the Proposed Rule
2. Remedial Actions
3. Review, Approval, and Enforcement Processes
4. Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria
5. Applicability (Coverage) of the Rule
6. Consensus Standard on Pipeline Integrity
7. Definition of High Consequence Areas
8. Requirements for Preventive and Mitigative Measures, including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Devices
9. Methods to Measure Program Effectiveness
10. Cost Benefit Analysis
11. Information for Local Officials and the Public
12. Appendix C Guidance

In addition, there were a variety of technical comments and suggestions concerning specific details of proposed Appendix C, and other technical language in the proposed rule. We did not include discussion of these detailed technical comments here but we did consider them in preparing the final rule and revising the Appendix.

RSPA personnel also had numerous discussions with representatives from several federal government agencies during this rulemaking to resolve issues the agencies had raised about the proposed rule. These agencies included the Environment and Natural Resources Division of the Department of Justice, (DOJ/ENRD); Fish and Wildlife Service (FWS), Bureau of Land Management, Office of Environmental Policy and Compliance and National Park Service from the Department of the Interior (DOI),¹ the Office of Ground Water and Drinking Water, Oil Program Center, and Region 3 from the Environmental Protection Agency (EPA); the National Transportation Safety Board (NTSB), the Council on Environmental Quality (CEQ); and the Office of Management and Budget. Where we have made changes to the rule to address comments

these agencies raised during the discussions, we have so indicated.

1. Clarity and Specificity in the Proposed Rule

The proposed rule used primarily performance-based language to allow operators to use pipeline- and location-specific information to determine the necessary integrity management practices. The proposed rule used specification language to prescribe the required elements of an integrity management program and baseline assessment plan, the allowable methods of integrity assessment and the required intervals for conducting baseline and continual assessments. The proposed rule also specified that an operator was to follow best industry practices unless a rule section specified otherwise or the operator could justify reasons for deviating from such practices and that the deviation was supported by a reliable engineering evaluation.

The proposed rule recognized that an integrity management program was an evolving program that an operator needed to continually improve.

API and the liquid operators supported the proposed rule's holistic approach to pipeline integrity management that incorporated risk assessment and risk-based decision making. API further praised the use of performance-based language in OPS's regulations. Koch commented that "a pipeline integrity management program allows an operator to consider the unique factors that impact a specific pipeline or pipeline segment and is more effective in improving pipeline safety than prescriptive regulations that treat all pipelines, no matter what their characteristics or where they are located, the same."

Environmental Defense, other advocacy groups, and other commenters maintained that the rule should have more specific requirements. These commenters stated that without such specificity, OPS would not be able to evaluate the adequacy of operator programs and enforce the rule. The City of Austin cautioned against a performance-based approach and urged us to clearly define the performance requirements and standards for monitoring, inspection and response.

NTSB reiterated its ongoing concern that OPS have regulations that contain measurable standards for performance.

EPA Oil Program Center commented that the proposed rule failed to include the specific requirements for an integrity management program or the process for determining if a pipeline will affect a high consequence area. The City of Austin said the rule should

¹ The Department of the Interior submitted comments to the docket in the USA rulemaking (RSPA-99-5455). We will consider and address those comments in that rulemaking. The DOI comments we discuss in this rulemaking were made during the inter-agency meetings.

require an operator to determine the potential impact for a worst case spill. Colonial Pipeline recommended that the rule clarify, either in the regulatory language or through guidance, how pipelines outside the high consequence area could affect the area.

API recommended that the rule recognize the value of planning changes and allow an operator to make changes to the baseline assessment plan.

DOJ/ENRD expressed concern that the proposed rule's language about an integrity program being an evolving program that an operator had to continually improve left too much to the operator's discretion. DOJ/ENRD had similar concerns with the language about an operator using and documenting a practice other than a standard industry practice. DOJ/ENRD further thought a deviation from a standard practice should only be allowed when new technology is being used. DOJ/ENRD also strongly urged substantial revisions of the proposed rule to improve its enforceability. DOJ/ENRD wanted clearly stated and unambiguous requirements for specific actions that achieve measurable results, the violation of which subject the operator to meaningful penalties.

NTSB expressed concern about the proposed rule's use of the term best industry practices without explaining where these practices could be found. EPA Region III also questioned who would be responsible for establishing, compiling, and disseminating the best industry practices.

API commented that the term best industry practices may cause controversy over its meaning and suggested that the term proven industry practices would be more appropriate.

Response:

To achieve effective integrity management programs that evolve and take advantage of changing technologies, the final rule uses both performance and specification-based language.

Based on our considerable experience with performance-based regulations, OPS believes that performance-based language will best achieve effective integrity management programs that are sufficiently flexible to reflect pipeline-specific conditions and risks.² However, we recognize that certain elements of the rule need to be written in specification language.

Performance-based standards allow an operator to select the most effective

processes and technologies as they become available. OPS wants to create incentives for operators to invest in the development of new technology. Because internal inspection technology and other integrity monitoring equipment have changed considerably in recent years and are expected to continue to improve, we want to encourage operators to use and strive to improve the best available technologies and processes. Thus, rather than only specify the use of currently available technologies, parts of the rule are performance-based to allow operators to develop customized programs that address pipeline-specific characteristics, are fully integrated into company safety and environmental protection programs, and use the best available technologies to assess and repair pipelines.

The specification parts of the rule ensure uniformity among integrity management programs so that they all address key issues, such as baseline and continual integrity assessment intervals, information integration and analysis requirements, and time frames to review and analyze integrity assessment results and to complete remedial actions.

As suggested by commenters, we have revised the rule to allow an operator to modify its baseline assessment plan and to clarify the basis for an operator changing and improving its integrity management program. We have added a provision allowing an operator to modify its baseline assessment plan so long as the operator documents the modification and reasons for the modification. An operator would have to document any modification at the time the decision is made to modify the plan, not at the time the modification is implemented. OPS enforcement personnel would review these supporting documents during a field inspection.

Although reworded, the rule still provides that an integrity management program is a continually changing program. However, the rule now specifies that 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. The rule also clarifies that an operator's integrity management program will evolve from the initial program framework the operator develops.

We have revised the rule to clarify that the integrity management program requirements apply to each pipeline segment that could affect a high consequence areas. An operator's

program must address the risk factors each pipeline segment poses to a high consequence area.

The proposed rule specified required elements of an operator's integrity management program. Other than some minor word changes and edits, we have not changed those elements in the final rule. We believe these elements will ensure sound integrity management programs.

However, to address commenters' concerns that the proposed rule failed to specify a process for determining if a release could affect a high consequence area, we have added two related requirements: that, as a first step, an operator identify all pipeline segments that could affect a high consequence area and also include a process in its program for identifying which pipeline segments could affect a high consequence area. (Identifying those segments that could affect an area involves determining if a release from a segment in or near a high consequence area could affect the area.) Although we did not propose these requirements in the notice, we believe they were implicit. Whether explicitly stated or not, an operator would have to identify which pipeline segments could affect a high consequence area before determining how the line pipe in those segments would be assessed. Moreover, since the trigger for the integrity management program requirements is whether a pipeline segment could affect a high consequence area, an essential element must be a process for identifying those pipeline segments that could affect the defined high consequence areas. In the Appendix to the rule, we have also provided guidance to help an operator in identifying high consequence areas and in evaluating how a pipeline release could affect a high consequence area. This guidance will help an operator in developing the required process.

The final rule requires that an operator follow recognized industry practices unless the rule otherwise requires a different practice or the operator can demonstrate that an alternative practice is supported by a reliable engineering evaluation. Paragraph (b)(3) does not affect an operator's obligation to comply with all other requirements in this rule. In the final rule, we have changed the term best industry practices to recognized industry practices. We believe this is an easily understood term by operators and enforcement personnel. Recognized industry practices include those found in national consensus standards or reference guides, and generally conform to the practices of the American

² Our using performance-based language in the rule is consistent with the Administration's policy of using performance-based standards. (See Executive Order 12866, Section 1(b) The Principles of Regulation (September 30, 1993).)

National Standards Institute. Companies' successful use of these practices helps determine their validity and acceptance. We have further revised the provision to clarify the basis for an operator using an alternative practice. The rule now provides that an operator's selection of an alternative must be based on a reliable engineering evaluation. Use of an alternative must provide an equivalent level of public safety and environmental protection. An operator must document its use of an alternative practice from when the operator makes the decision to use the alternative. An operator must be able to provide the documentation to OPS enforcement personnel for review during a field inspection.

We have not limited an operator's use of alternative practices to only when new technology is being used. For example, an alternative practice could be one that has been successfully used in other countries or by other pipeline companies but has not yet been codified into a national consensus standard. OPS wants to encourage operators to use innovative practices that are based on sound engineering judgment. OPS also wants to encourage innovation in technology and recognizes that an existing technology may be improved and given a new application.

We have also revised language throughout the rule to make the rule clearer and more understandable. These changes have not affected the requirements of the rule, most have simply been made to improve the rule's overall clarity and to ensure the consistency in use of terms. Others have been made to address DOJ's concerns about making the rule more specific and enforceable and clarifying the operator's required responsibilities under the rule. Any substantive changes are discussed in this document.

2. Remedial Actions—Proposed Section 195.452(g)

The proposed rule required an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and data integration analysis. The rule proposed that an operator evaluate and repair all defects that could reduce a pipeline's integrity, and establish an evaluation and repair schedule. The rule did not propose time frames for making the repairs, other than an operator could not operate the affected part of its pipeline system until it had corrected a condition presenting an immediate hazard. The NPRM also asked for comment on whether the rule should contain specific time lines for conducting repairs.

API was against specific time lines and said that criteria for when repairs should be implemented could not be reduced to simple statements suitable for inclusion in the rule. API added that the consensus standard will offer guidance to operators. Enbridge stated that a one-size-fits-all time frame for conducting repairs is not practical or technically justified; however, Enbridge said that it supported the goal of ensuring that no imminent hazard is left unaddressed.

Environmental Defense recommended a relatively short time to conduct repairs after serious defects are identified, e.g., one month to complete repairs unless pipeline pressure is significantly reduced. The City of Austin said that the rule should include repair time lines, acceptable methods of remediation and a better definition of what pipeline flaws constitute an immediate hazard. The City of Bellingham also recommended that the rule establish a specific and expeditious deadline for conducting repairs. EPA Region III commented that the proposed rule did not define what conditions constituted immediate hazard conditions.

Peoples Energy commented that the proposed language about which anomalies an operator had to evaluate and repair only applied to defects that could reduce integrity. Peoples Energy pointed out that this determination could not be made until an operator reviewed all data.

DOJ/ENRD questioned the ability to enforce performance-based standards, particularly with respect to the proposed repair provisions. DOJ/ENRD requested that the regulation be written in language that requires an operator to take specific action. DOJ/ENRD based its concerns on its experience with enforcing the Clean Water Act. DOJ/ENRD was particularly concerned that the proposed rule would not ensure that repairs were made before failures occurred and strongly recommended that language be added specifying when an operator would have to make repairs on the pipeline. DOJ/ENRD also strongly urged that the rule include a provision establishing a cut-off time for when an operator had to review and analyze the results from an internal inspection, and recommended a phased-in approach.

Response: We have rewritten the remedial action section of the final rule to accommodate DOJ/ENRD's and other commenters' concerns. To be consistent with the wording used to describe required program elements, we have renamed the section to reflect the broader actions an operator must take to address integrity issues raised by the

assessments. The rule has been revised to specify time frames for reviewing and analyzing the results of an integrity assessment and for completing repairs of certain conditions (see § 195.452(h)).

The rule still requires an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and information integration. The rule now clarifies that an operator is required to evaluate all anomalies and repair those that could affect the pipeline's integrity. Prompt action means that an operator must make the repair as soon as practical. However, an operator must prioritize the repairs according to the severity of each anomaly and address first those anomalies that pose the greatest risk to the pipeline's integrity.

The rule now requires that an operator complete repairs according to a schedule that prioritizes anomalies found during the integrity assessment for evaluation and repair. In this schedule, an operator would have to provide for review and analysis of the integrity assessment results by a date certain. The review and analysis must be done by a qualified person (*i.e.*, a person who has the requisite knowledge and technical expertise to review the results and analyze the data.) For the first three years after the rule's effective date, an operator would determine the period by which the results would have to be reviewed and analyzed and commit that date in writing in its schedule. After the third year, an operator's schedule must provide for review and analysis of the integrity assessment results within 120 days of conducting each assessment. The rule allows more flexibility in the first three years so that OPS can review the adequacy of time frames operators establish, and gather sufficient information to determine what the required standard for review and analysis of assessment results should be. OPS recognizes that a time frame depends, in part, on the availability of persons with expertise to evaluate the data. OPS further recognizes that a quality review and analysis takes time. By the end of the third year OPS will have sufficient information to be able to determine if it should revise the 120-day required period.

An operator's schedule also has to provide time frames for evaluating and completing repairs. A qualified person must conduct the evaluation (*i.e.*, a person with the requisite knowledge and technical expertise.) Because an operator must prioritize the repairs, the rule provides that the operator is to base the repair schedule on specified risk factors and pipeline-specific risk factors

the operator develops. For conditions not specified in the rule, the operator determines the schedule for evaluation and repair. However, the rule provides the time frames in which an operator must complete repair of certain conditions on the pipeline. These conditions are listed as immediate repair conditions, 60-day conditions and 6-month conditions. The time frame required for repair starts at the time the operator discovers the condition on the pipeline, which occurs when an operator has adequate information about the condition to determine the need for repair. Depending on circumstances, an operator could have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or receives the final internal inspection report.

In the proposed rule we used the term immediate hazard for certain conditions, and referenced § 195.401(b). In the final rule we refer to these as immediate repair conditions and identify several. Under § 195.401(b), an immediate hazard condition requires that an operator shut down the pipeline until the operator has corrected the condition. With an immediate repair condition, as long as safety is maintained, an operator will either be able to temporarily reduce operating pressure or shut down the pipeline until the operator can complete the repair of the condition.

An operator may deviate from the rule's specified repair times if the operator justifies the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. OPS enforcement personnel will review any justifications and supporting documents during site inspections. In certain cases when an operator cannot meet the required schedule and cannot provide safety through a temporary reduction in operating pressure, the operator must notify OPS. This will allow OPS to determine the extent of review needed and if an inspection is needed. The rule specifies how an operator must notify OPS.

In the NPRM we discussed the consensus standard that an ANSI workgroup was developing on integrity management. OPS has been participating in the work group. In the notice, we said that we would consider adopting all, or part of, the standard once it was final, but only after public notice and comment. (More discussion about the consensus standard appears

later in this document under the topic heading "Consensus standard on pipeline integrity.") The standard is not yet final. However, OPS is basing the provisions in section 195.452(h) on initial indications of what will be in the final consensus standard. We believe that the criteria being considered by the standard's workgroup adequately address pipeline integrity concerns because the criteria are based on a structured methodology for evaluation of internal inspection devices data. The methodology is a recognized industry practice. The criteria are also based on well-established consensus standards, such as the American Society of Mechanical Engineers (ASME) B31.4 standard. ASME B31.4 is a widely-recognized and long accepted standard on liquid transportation systems for hydrocarbons, liquid petroleum gas, anhydrous ammonia, and alcohols. (The regulations in 49 CFR Part 195 were developed from ASME B31.4.)

Although a consensus integrity standard is not yet final, we have made available at OPS's website, notes of the meetings, and a peer review draft of the standard on Managing Pipeline System Integrity. The standard is expected to be completed and published in December, 2000.

We recognize that we have completely restructured the section of the rule pertaining to actions an operator must take to address pipeline integrity issues. Because of the extensive changes to this section of the rule, we are allowing 60 days comment on the provisions in section 195.452(h). Based on the comments we receive, we will consider modifying the provisions. At the end of the comment period, we will either issue a modification or a notice stating that the section stands as written.

An operator has one year from the effective date of the rule to develop the framework for an integrity management program. An operator has 3½ years from the rule's effective date to conduct a baseline integrity assessment of the highest risk line pipe segments. An operator is not likely to take remedial actions required by this rule until after the integrity assessment. Thus, remedial action criteria are not needed until some time after the rule's effective date. We expect to issue any modifications so that operators have ample time to incorporate the modifications into their program framework. If we are delayed in issuing the modification so that operators do not have adequate lead time, we will then consider further delaying the compliance date for section 195.452(h). Until OPS announces a modification, operators can base their

program remedial action criteria on those set forth in this rule.

3. Review, Approval and Enforcement Processes

Some commenters questioned why the proposed rule did not provide for adequate and timely OPS review and approval of an operator's baseline plan, integrity assessments, and integrity program. The proposed rule requires an operator to maintain for inspection written documentation of its program and assessment plan, and of any evaluation or analysis made to support a decision or action. The rule did not propose requirements for formal transmittal of baseline assessment plans, assessment results, or integrity management programs to OPS for approval.

Lower Colorado River Authority (LCRA) supported the flexibility of a performance-based approach but cautioned that the commensurate accountability component seemed to be missing. LCRA explained that the proposed rule did not provide a mechanism for OPS review, or approval of critical decisions made by an operator or indicate that OPS would have any involvement in program implementation. The City of Austin maintained that the proposed rule seemed to continue reliance on the regulated community to implement pipeline safety regulations at their own discretion, with only minimal regulatory oversight. The City of Austin cautioned that close regulatory review and oversight are needed and strongly urged OPS to require all integrity management programs to be submitted for OPS approval, as well as assessment reports.

EPA Oil Program Center expressed concern that the proposed rule relied "heavily on a pipeline operator's assessments, assumptions, and evaluations, yet requires no formal approval process by the Office of Pipeline Safety or certification by a third party, such as a Professional Engineer."

Several commenters questioned OPS's ability to adequately enforce the proposed rule because of inadequate data, knowledge, or expertise. EPA Region III stated that the bulk of expertise in this subject area seemed to reside with the pipeline industry because of the proposed rule's reliance on industry's efforts to evaluate and resolve risk issues concerning pipelines. Region III further stated that OPS must obtain and/or develop independent expertise and knowledge for effective oversight. Friends of the Aquifer commented that because of the lack of

accurate data about pipeline spills, OPS would not be able to judge the adequacy of the risk factors included in an operator's plan.

Response: OPS agrees that an effective and credible inspection process is critical to achieving the objectives of the rule. OPS is developing protocols and criteria for detailed inspection of operator baseline assessment plans and integrity management programs to ensure that operators comply with the requirements of the rule, and that operators use structured, documented, and technically defensible processes and models to support assessment priorities and time frames, decisions on remediation, prevention and mitigation, and measures of program effectiveness.

OPS has already developed expertise in enforcing performance-based regulations and in evaluating risk-based decision processes. OPS has contracted for additional training in specific technical areas to improve the qualifications of its enforcement personnel. OPS plans to have a sufficient base of trained enforcement personnel who will review the integrity management programs during on-site inspections of pipeline operators. OPS will contract for any needed technical expertise to supplement the knowledge of its enforcement personnel.

We are not requiring formal approval of an operator's integrity management program or of decisions and analyses made to develop and implement the program. Rather, a multi-disciplined team composed of OPS regional inspectors, and technical specialists from headquarters will conduct integrity management program inspections. In addition, OPS will contract for other technical expertise, as needed. We are also planning how best to involve state pipeline safety inspectors in the review.

We have also added requirements that an operator provide advance notice to OPS when the operator plans to use other technology (other than internal inspection or pressure test) for a baseline or continual integrity assessment or intends to justify a longer continual assessment period. (We discuss these advance notice requirements later in the document.) We determined that an advance notice requirement was necessary in certain instances to give OPS enforcement personnel additional time to review and evaluate an operator's rationale and supporting documentation.

The rule continues to require an operator to document all aspects of its integrity management program so that OPS enforcement personnel can review these documents during an inspection to determine an operator's compliance

with the rule. We have clarified the language in the final rule concerning the types of documents an operator is required to maintain. Required documents include those to support decisions and analyses made, as well as modifications, justifications, deviations, variances and determinations made, and actions taken to implement and evaluate each of the required program elements. This requirement is no different from other requirements in the pipeline safety regulations that an operator maintain current maps and records of its pipeline system, maintain a procedural manual for operations, maintenance and emergencies and maintain other records of tests and inspections. In Appendix C we have provided some examples of records an operator would have to maintain for inspection. We also discuss recordkeeping requirements in greater detail later in this document in the section by section analysis (section 195.452(1)).

4. Program Implementation and Integrity Assessment Time Frames, Assessment Methods and Criteria—Proposed Sections 195.452(b)–(e) and (j)

The notice proposed that an operator develop and follow a written integrity management program within one year after the final rule's effective date. The proposed rule included a seven-year time frame for the baseline assessment, with an operator having to assess 50% of the mileage within 3.5 years, and a ten-year maximum interval for continual integrity re-assessments. The notice proposed that an operator conduct the integrity assessment by internal inspection, pressure test, or new technology that could provide equivalent protection to the other two methods.

The proposed rule disallowed use of a magnetic flux leakage or ultrasonic internal inspection device for a pipeline segment constructed of low frequency ERW pipe or lapwelded pipe susceptible to longitudinal seam failures. This was done to be consistent with current requirements in section 195.303 providing that an operator's program for testing a pipeline on risk-based criteria provide for pressure testing of a segment constructed of either of those types of pipe.

The notice also proposed allowing as a baseline assessment an integrity assessment that an operator had conducted within five years prior to the effective date of a final rule.

The proposed rule permitted an operator to choose between two options in establishing baseline and continual assessment schedules. The first option specified risk factors to use in

establishing the schedule. The second option permitted an operator to base the schedule on risk factors the operator considered essential in risk or consequence evaluation. This option would have given an operator some flexibility to establish re-assessment intervals exceeding ten years.

Implementation

API recommended that program implementation be keyed to OPS making available to operators a complete set of maps designating the high consequence areas rather than to the final rule's effective date.

The National Pipeline Reform Coalition objected to the one-year program development period based on OPS's estimate in its cost/benefit analysis of how long it would take an operator to develop an integrity management program. OPS had estimated 430 hours.

Assessment Time Frames

API and the industry commenters suggested that OPS establish January 1, 1995 as the cut off date for acceptability of prior integrity assessments, rather than tying the cutoff date to a final rule date. Enbridge and Lakehead asked that operators be allowed to justify older assessments, rather than OPS arbitrarily excluding those older than five years.

API also said that the proposed seven-year baseline and ten-year re-assessment periods were reasonable, and would allow operators to make decisions based on the characteristics of their pipeline system. The hazardous liquid operators re-iterated and concurred with API's comments.

Advocacy and environmental groups, and other commenters objected to the proposed seven-year baseline assessment and ten-year re-assessment periods. Some also objected to allowing a five-year old prior assessment to satisfy the baseline assessment. Environmental Defense suggested a three-year maximum, only allowing baseline assessments that have occurred within two years of the rule. For the continual re-assessment interval, Environmental Defense recommended that OPS follow the California model, and require re-assessment every five years. The City of Bellingham suggested that baseline assessments should be completed in one to three years, and periodic updates within five years. Fuel Safe Washington objected to allowing any prior baseline assessments, and suggested that baseline assessment be completed within 18 months, and that re-assessment be required at a maximum of five years, three years for pipelines constructed prior to 1970, and one year

for pipelines located in unusually sensitive environmental areas. Pipeline Survivor's Association argued that baseline assessments should be completed in three years, with 50% of that mileage being assessed in 18 months, prior assessments be limited to one year before the rule, and re-assessments intervals be shortened to five years. The City of Austin recommended five years for establishing the baseline, 2.5 years to complete 50% of the baseline, and five years for reassessment. Batten & Associates recommended a baseline assessment period of three years, limiting prior allowable integrity assessments to one year before the rule's effective date, and re-assessment intervals of three years. LCRA recommended a seven-year time frame for completing the baseline integrity assessment and shortening the ten-year time frame for re-assessment in some instances based on pipeline-specific risk factors (e.g., age of pipe, leak history, etc.).

Several federal agencies also objected to the proposed integrity assessment time frames. NTSB urged us to reduce the period for the baseline assessment because it could not find sufficient data in the proposed rule to justify the seven-year period. EPA Oil Program Center suggested a five-year time frame for completing the baseline, with 50% of the mileage completed within 30 months. EPA Region III also recommended a five-year continual assessment period because it would provide useful integrity/deterioration information, without imposing too great a burden. DOJ/ENRD raised concern with the proposed seven-year baseline and ten-year continual assessment intervals and strongly recommended shorter baseline and continual integrity assessment intervals. DOJ/ENRD said OPS could not demonstrate that defects would not propagate to failure within the proposed seven-year period. DOJ/ENRD also questioned the basis for OPS's assumption that a ten-year interval was reasonable if a pipeline was adequately cathodically protected.

Assessment Schedule Criteria

The City of Austin recommended eliminating Option 2—allowing an operator to establish an assessment schedule based on factors it determines essential—because it would not be feasible for an operator to demonstrate “an equivalent level of safety and environmental protection as Option 1 given the extremely complex inter-workings of the many potential risk factors.” The advocacy groups argued for dropping Option 2 from the rule because it provided the operator too

much discretion. EPA Region III also stated that Option 2 may provide “too loose a regimen” and supported the approach described in Option 1. Environmental Defense preferred “a modified Option 1 in which operators could identify and report any additional risk factors to those specified in the rule.” The National Pipeline Reform Coalition also recommended eliminating Option 2 because Option 1 allowed enough flexibility for an operator to determine that a specified risk factor had little or no applicability to its operations and discount the factor.

Several commenters suggested risk factors that the rule require for establishing assessment frequency. NTSB recommended that OPS not let an operator determine what factors are essential for ensuring a pipeline system's safety and environmental protection; rather the rule should specify minimum factors that an operator must consider in establishing an assessment schedule. NTSB suggested these factors include the results from previous inspections, the pipeline's leak history, material and coating conditions, cathodic protection history, type of pipe seams, product transported, operating pipe stress levels, defect types and sizes detectable by the inspection method used, defect growth rates, and effectiveness of actions taken to correct chronic problems, such as corrosion. EPA Region III suggested that risk factors for establishing frequency of assessment should also include, product specific differences, location related to the ability of the operator to detect and respond to a leak (e.g., pipelines deep underground) and non-standard or other than recognized pipeline installations (e.g., horizontal directional drilling).

National Pipeline Reform Coalition suggested risk factors such as pipe material and manufacturing processes, highly corrosive soils, and highly volatile products being transported. Dynegy suggested that highly volatile liquids not be treated as other hazardous liquids because they do not pose the same potential for damage to sensitive environmental areas. SEFBO recommended that the rule distinguish overhead suspension pipeline bridges from other above ground pipeline support structures because more sophisticated skills and experience are required to inspect and maintain cable structures. Sen. Breaux also urged that we address the role of these bridges in high consequence areas.

Assessment Methods

API expressed satisfaction that the proposed rule not only recognized that internal inspection tools provide

valuable information but also recognized that a single tool or integrity assessment methodology is not always the answer, and that integrity can be assessed by various inspection methods. API and Equilon, however, suggested that we delete the footnote in the proposed rule preventing operators from using magnetic flux or ultrasonic internal inspection tools on low frequency electric resistance (ERW) welded pipe. API suggested language to ensure that the integrity of ERW seams is adequately assessed. Colonial Pipeline was pleased that the rule recognized the value of internal inspection technology and recognized that technology is constantly evolving.

Koch suggested that the rule allow an alternative assessment methodology in situations where it would be appropriate to conduct an assessment by means other than internal inspection, pressure test, or equivalent new technology. Peoples Energy questioned why the proposed rule did not allow for use of current technology, such as sonic or optical methods, that could be made feasible for pipelines.

Dynegy pointed out that a leak during a hydrostatic test could damage the environment and that installing magnets needed for instrumented internal inspection could also damage an area.

Response:

Implementation

The final rule keeps the one-year period from the rule's effective date for an operator to develop an integrity management program. However, the rule now requires that an operator identify all pipeline segments that could affect high consequence areas within nine months from the rule's effective date. Although implicit that an operator would have to identify the pipeline segments that were covered by the rule, the proposed rule did not propose that an operator do this. Because identification is a necessary first step in the integrity management process, we did not think it unreasonable to make it an explicit requirement.

We have also clarified that during the first year an operator must develop a program framework that addresses each element of the integrity management program. The rule further clarifies that a program begins with the initial framework. Once the program framework is developed, an operator will then have to implement and follow the program. Because an integrity management program is dynamic, the rule provides that an operator must also continually change the program as the operator gains experience.

Assessment Intervals

We have not revised the time period for an operator to conduct a baseline assessment. OPS believes that a seven-year baseline integrity assessment cycle will result in a higher quality integrity assessment and analysis of the assessment results to better ensure the integrity of each pipeline segment. Further, OPS believes that this schedule will effectively double the rate of assessment currently being conducted. Finally, we decided not to establish a shorter baseline interval because an analysis OPS conducted found that internal inspection resources needed to meet demand for baseline assessment are marginally adequate until the year 2007. This finding took into account resources that will be needed concurrently for other assessments (apart from those this rule requires). (See memorandum from Noel Duckworth, dated October 1, 2000. This memorandum is in the docket.) We expect that internal inspection will be the primary choice of operators. Moreover, once we establish similar integrity management program requirements for liquid operators with smaller operations and for natural gas operators, these operators will all be drawing on the same market of vendors. Thus, to ensure that operators have adequate time to conduct high quality integrity assessments and to analyze the results from the assessments, we have kept the seven-year baseline interval.

Moreover, to ensure that the highest risk pipe is assessed early in the cycle, we have clarified that an operator must assess at least 50% of the pipe, beginning with the highest risk pipe, in the first 3.5 years of the seven-year baseline period. This requirement, coupled with the requirement to base the assessment intervals on risk-based factors and analyses, should ensure that an operator assesses the highest risk segments in a shorter time frame. An operator's schedule and rationale for establishing the assessment intervals are subject to review during an inspection.

The rule continues to allow as a baseline assessment an integrity assessment that an operator has conducted five years before the rule's effective date. However, we have revised the rule so that if an operator chooses to use a prior integrity assessment, the operator must then re-assess the pipe segment according to the continual integrity re-assessment requirements (discussed below). We believe that some operators will opt for using a prior integrity assessment to address integrity issues on a pipeline

segment that need prioritized remedial action.

One of the greatest concerns expressed by Federal government agencies, environmental groups and other advocacy groups (as discussed above) was that the proposed ten-year continual re-assessment interval was too long to ensure public safety and environmental protection. Because of the concern expressed, we did additional research and reconsidered the issue. Based on what we found, we have revised the final rule to shorten the continual re-assessment interval. The rule now requires an operator to establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity, unless the operator can demonstrate that one of the limited exceptions applies.

In deciding on the five-year interval, we relied extensively on an analysis OPS conducted on internal inspection devices (Noel Duckworth memorandum dated October 1, 2000). The analysis is available in the docket. The analysis found that, in 1999, the three major internal inspection device vendors in the U.S. logged 30,000 miles, at 68% utilization capacity, and in 2000, the vendors expect to log 45,000 miles at 90% utilization (maximum attainable). According to the memorandum, the analyst estimated that the total capacity of these three internal inspection device vendors would likely increase to about 87,000 miles by 2007. Our current estimates indicate that this rule is likely to apply to 35,500 miles of hazardous liquid pipeline. (Because of the location of pig launchers and receptors, which are typically located near pump stations 50 miles apart, operators will be internally inspecting more than the 35,500 miles of hazardous liquid pipeline required under the rule. We expect that at least 25–30% additional mileage or 44,375 miles will be internally inspected.) Additional internal inspection requirements will also be generated by future rules that will apply to smaller hazardous liquid operators and to natural gas operators. Therefore, according to the Duckworth memorandum, the three big vendors should be able to meet the demand for internal inspection devices, although demand will stress the capacity of the market. The memorandum noted that more is involved in integrity assessment than just running the internal inspection devices, and analyzing the data, but also about the planning/scheduling process between internal inspection tool companies and pipeline operators. Based on these findings, coupled with the insistent urging of several federal agencies (DOJ, NTSB, and EPA), and

many other commenters, who argued that a shorter continual integrity re-assessment interval was essential to protect public safety and the environment, we have reduced the re-assessment interval to a general requirement of five years, providing for exceptions.

The five-year integrity re-assessment period is not absolute. The rule allows variance in limited instances from the five-year period: when there is an engineering basis for a longer period or when the best technology needed to assess the segment is temporarily unavailable. For example, an operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe, if the operator can support the justification by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technologies, that provides an equivalent understanding of the condition of the line pipe. Or an operator may require a longer assessment period for a segment of line pipe because the best assessment technology, given the risk factors of the segment, is not available. An operator would then have to justify the reasons why it could not comply with the required assessment period and also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. In either instance, an operator would have to notify OPS before the end of the five-year period that the operator will be justifying a longer period. If the justification is based on engineering reasons, the operator must provide nine months notice before the end of the five-years. For unavailable technology, the operator must provide 90-days notice. Advance notice will give OPS sufficient lead time to review an operator's justification and supporting documents.

The rule continues to require that an operator base both the baseline and continual assessment intervals on the risk the pipeline segment poses to the high consequence area. To establish the assessment intervals, the rule requires that an operator use specified risk factors, the analysis of the results from the last integrity assessment, and information from the integration analyses. These factors and information will help the operator to prioritize the pipeline segments for assessment.

OPS inspectors will carefully evaluate each operator's methodology for determining the baseline and continual integrity assessment schedules to ensure that the highest risk segments are being addressed in the earliest time frames. OPS inspectors will also review an

operator's justification for deviating from the required five-year re-assessment interval. We have added the requirement for advance notice to OPS when an operator may vary from the five-year interval so that OPS inspectors have adequate time to review and evaluate the justification supporting the variance.

Assessment Criteria

We agree that appropriate flexibility for establishing an assessment schedule based on risk factors can be achieved by modifying Option 1 and deleting Option 2. The final rule requires that an operator base its integrity assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The rule also specifies certain factors that an operator must consider. These factors include those we proposed in the NPRM plus others suggested by NTSB, EPA, the THLPSSC and other commenters. However, the rule does not preclude an operator from including other risk factors specific to the pipeline being assessed. OPS wants to encourage operators to supplement the specified risk factors with factors relevant to the pipeline segment being assessed.

We have not changed the final rule to establish separate requirements for highly volatile liquids and other hazardous liquids, or for overhead suspension pipeline bridges. However, because highly volatile liquids and overhead suspension bridge pipelines may pose unique risks to a high consequence area, an operator's integrity management program must consider and address these risks. In the rule, we have added pipeline suspension bridges and product transported to the list of factors an operator must consider when establishing an assessment schedule. The Appendix provides an operator further guidance on establishing integrity assessment intervals.

Assessment Methods

The rule continues to allow a choice in the integrity assessment method—internal inspection tool, pressure test, or other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. We did not provide for another assessment method in lieu of the three permitted methods. We believe that the three permitted methods give an operator sufficient flexibility to conduct integrity assessments appropriate to each pipeline segment that must be assessed.

The rule provides that an operator choosing assessment by internal

inspection must use a tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges and grooves.

We have revised the rule to delete the footnote about not using a magnetic flux leakage or ultrasonic internal inspection tool on ERW pipe. We recognize that technology in the internal inspection industry has been changing rapidly. Now, there are readily available tools, for example, ultrasonic (shear wave) and circumferential magnetic flux leakage tools, that can detect longitudinal seam failures. Therefore, the rule now allows an operator to use integrity assessment methods on ERW pipe and on lapwelded pipe susceptible to longitudinal seam failures that can assess seam integrity and can detect corrosion and deformation anomalies. An operator's integrity management program would also have to address the special risks of these types of pipe.

In the final rule we clarified that a pressure test must be conducted according to the requirements for pressure testing found in Part 195, subpart E. An operator choosing to assess by pressure test should also evaluate its corrosion control program before deciding on this option.

OPS inspectors will review the operator's selection of assessment methods for the relevant pipeline segments. OPS personnel will particularly look at the adequacy of the operator's corrosion control program when evaluating an operator's choice to pressure test.

We used the term *new technology* in the proposed rule as an operator's third option. In the final rule, we changed that term to *other technology*. Other technology would include new or existing technology that is adapted for pipeline use and provides an equivalent understanding of the condition of the line pipe as the other two methods. We have also changed the language that the other technology must provide *an equivalent level of protection in assessing the integrity of the line pipe* to that it must *provide an equivalent understanding of the line pipe*. We believe this language better reflects what an assessment tool does i.e., it does not protect the pipe but gives the operator an understanding of the condition of the line pipe.

If an operator chooses other technology as its assessment method, the operator must notify OPS 90 days before using the technology so that OPS has adequate time to review the technology.

5. Applicability (Coverage) of the Rule—Proposed Section 195.452(a)

The proposed rule applied to operators that operate 500 or more miles of hazardous liquid pipeline used in transportation. If an operator fell into that category it would then have to develop an integrity management program for all segments of pipeline that could affect a high consequence area.

EPA Oil Program Center, the National Pipeline Reform Coalition, and other advocates suggested that this rule should apply to all hazardous liquid pipelines. EPA Oil Program Center expressed confusion about whether the rule applied only to pipelines that were 500 miles long or longer. The City of Austin pointed out that smaller operators might be more likely to have poorer maintenance and operating practices. BP Amoco also urged OPS to require all hazardous liquid operators to comply with the proposed rule, expressing concerns that pipeline companies might structure their operations in a manner to avoid applicability of the rule.

NTSB suggested that integrity management requirements should apply to hazardous liquid pipelines no matter where they are located, not just those pipeline segments that could affect high consequence areas.

API and the individual operators commented on the need for greater clarity in the portions of a pipeline facility to which the rule would apply. These commenters said that OPS needed to clarify whether the integrity management program requirements were limited to the line pipe or were intended to cover other facilities included in the definition of pipeline (e.g., pump stations, valves, breakout tanks). The pipeline industry commenters suggested that the rule be limited to the line pipe and that we address integrity issues for the other pipeline facilities in a separate rulemaking.

API also suggested that the final rule clarify that it is limited to onshore pipeline systems, and that OPS conduct a separate rulemaking on integrity management for offshore pipeline systems. API, and other industry commenters, explained that offshore lines may not be capable of accommodating internal inspection devices. API also noted that offshore pipelines pose different risks from onshore pipelines. BP Amoco thought it appropriate to include only offshore pipelines that could affect USAs in an integrity management program because offshore operations pose a limited, if any, risk to public safety. The company

listed technical factors that should be considered in establishing integrity requirements for these lines. Chevron also noted that offshore lines present technical and configurational differences from onshore lines.

SEFBO and Sen. Breaux commented that the rule should clearly distinguish overhead suspension pipeline bridges because of the different skills and experience required for inspection and maintenance of such structures. Dynege recommended that the rule exempt highly volatile liquid product pipelines that traverse wet or flooded areas, instead, that we cover those lines under the gas integrity management program rule.

Response: The final rule clarifies that it applies to each operator who owns or operates a total of 500 or more miles of pipeline used in hazardous liquid transportation. If an operator has 500 or more miles of pipeline in its system, then the operator's integrity management program must address the risks on each pipeline segment in its system that could affect a high consequence area. The length of an individual pipeline segment that could affect the high consequence area is irrelevant to whether it is covered.

Moreover, as we explained in the NPRM, we have no intention of excluding hazardous liquid operators with smaller operations. Our public discussions had given us ample information to proceed with a proposed rulemaking aimed at larger liquid operators. While we proceeded with the first part of the rulemaking (liquid operators owning or operating 500 or more miles of pipeline), we continued to obtain further information about smaller liquid operations so that we could propose integrity management program requirements applicable to those systems. The next step in our series of rulemakings that will ultimately require all regulated pipeline operators to have integrity management programs is to propose integrity management program requirements for hazardous liquid operators who own or operate less than 500 miles of pipeline.

In this rulemaking we have not extended the pipeline integrity requirements to pipelines beyond those that could affect a high consequence area. We continue to focus on pipeline segments that could affect the areas we define as high consequence areas: populated areas, unusually sensitive environmental areas and commercially navigable waterways. However, we expect that many of the measures the rule requires for pipeline segments that could affect high consequence areas will benefit other parts of the pipeline

system not covered by the rule. For example, the final rule requires an operator to analyze and integrate various information about the integrity of the entire pipeline. This analysis is likely to benefit other segments of the pipeline system. The additional preventive and mitigative measures that an operator must take to protect the high consequence area should also yield benefits beyond the segment in the critical area.

Because of the location of launchers and receivers on a pipeline, an assessment by internal inspection is likely to benefit an additional 25–30% of pipeline beyond that covered by this rule. An operator may also choose to extend the integrity assessment beyond the pipeline segment that could affect the high consequence area.

The final rule clarifies the pipeline facilities covered by the integrity management program requirements. The integrity management program requirements apply to each pipeline segment that could affect the high consequence area. We are using the term pipeline as it is defined in § 195.2; the term includes, but is not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, metering and delivery stations, and breakout tanks. Integrity management addresses more than material issues in line pipe, but other issues such as adequacy of procedures, operator training, and other issues related to the pipeline facilities.

The rule clarifies that the baseline integrity assessment, which involves internal inspection, pressure test, or other equivalent technology applies only to the line pipe. (Line pipe is defined in § 195.2.) The continual integrity assessments, done at intervals not to exceed five years, also are limited to the line pipe.

The continual evaluation and information analysis requirements, however, apply to the entire pipeline. To ensure that a high consequence area receives broad protection, an operator must evaluate all threats to and from the pipeline, and consider how operating experience in other locations on the pipeline could be relevant to a segment that could affect a high consequence area. Thus, the rule requires an operator to periodically evaluate the integrity of each pipeline segment that could affect a high consequence area by analyzing all available information about the entire pipeline. This information would include 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; information about how a failure would affect location of water intake; and information gathered in conjunction with other inspections, tests, surveillance and patrols required in Part 195, including, corrosion control monitoring and cathodic protection surveys. This information analysis will be done in conjunction with the periodic evaluation and continual integrity assessment of each pipeline segment.

The rule does not apply to all offshore pipelines, only to those offshore pipeline segments (and onshore pipeline segments) that could affect a high consequence area. Offshore pipelines could, particularly, affect unusually sensitive environmental areas (USAs) and commercially navigable waterways. We are including these offshore pipeline segments because of their potential to impair unusually sensitive ecological resources, to disrupt the flow of goods to communities, or to impair unusually sensitive drinking water resources. We discuss later in this document all areas that are included as high consequence areas. (See discussion under topic heading "Definition of High Consequence Areas.") We also explain how these areas will be shown on the National Pipeline Mapping System (NPMS).

We have also added offshore pipelines to the list in Appendix C of risk factors that an operator should consider in establishing an integrity assessment schedule. Generally, risks associated with offshore lines are because of climatic or geological factors.

We did not accept the recommendation to exempt highly volatile liquid (HVL) product pipelines from this rule. (HVLs are covered under Part 195 because they are and behave like hazardous liquids when transported by pipeline under pressure.) Rather, as discussed previously in this document, we have added highly volatile liquids (or product transported) and pipeline suspension bridges to the list of risk factors an operator must consider in establishing an integrity assessment interval. And as we discuss later in the document, these factors have also been added to the specified factors an operator must consider when analyzing the need for additional protective measures for the pipeline segment.

6. Consensus Standard on Pipeline Integrity

In the NPRM, OPS mentioned that API was sponsoring an American National Standards Institute (ANSI) work group to develop a consensus

standard on integrity management. We said that we expected the consensus standard would provide detailed guidance to operators developing and implementing an integrity management program. We further said that once the standard was final, we would consider adopting it into the integrity management rule, but only after we had provided a public notice and comment period prior to incorporating it into the rule. The work group is continuing its work on the standard and is seeking comment on the draft of the standard.

There was a difference of opinion among commenters concerning an industry group's role in coordinating the development of a standard. Environmental Defense and other public advocates, expressed concern over API's role, and suggested use of a neutral engineering society. The City of Austin urged RSPA to develop standards using a team of stakeholders that includes the regulated community, local officials, experienced safety engineers, and other appropriate experts.

API responded that the standard is being developed using the procedures of the American National Standards Institute and includes broad participation from operators, vendors, representatives from the American Society of Mechanical Engineers (ASME), the National Association of Corrosion Engineers, OPS, and pipeline safety advocates.

EPA Region III said that the pursuit of an industry consensus standard by both the API and OPS is encouraging, but asked about the direct involvement in that process by OPS and other federal agencies, and the current review procedures for such standards.

Response: The standard being developed will be a consensus standard of the American National Standards Institute (ANSI), developed using the standard development procedures of this independent organization. The work group of technical experts includes representatives from government, industry, and members of the American Society of Mechanical Engineers (ASME). When the work group was created in February 2000, environmental and other advocacy groups were invited to join the work group.

The work group's meetings are open to the public. Public participation has been encouraged. Minutes of the meetings have been posted on OPS's website. The resulting draft standard is being distributed for public comment before publishing, allowing input and review from all stakeholders.

The Executive Committee of ASME B31.4 has also agreed, at OPS's request,

to undertake a peer review of this ANSI standard to ensure that the standard adequately addresses the regulatory requirements. The ASME Executive Committee is expected to complete this peer review during fall 2000.

Accordingly, we believe that the ongoing standard development process has the appropriate and adequate checks and balances built in to produce a technically sound product that can support the development and implementation of high quality integrity management programs. We expect this standard will provide more detailed guidance to operators on the specific elements and acceptable processes of an integrity management program, and can supplement the performance-based portions of the rule. Once the consensus standard is final, we will consider adopting, all or part of it into this final rule. However, we will only do so after we have provided for public notice and comment.

7. Definition of High Consequence Areas—Proposed Section 195.450

The proposed rule's definition of high consequence areas had three components: populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways.

Populated Areas

The notice proposed that populated areas consist of high population areas and other populated areas. The proposed rule based these areas on Census Bureau definitions.

The City of Austin thought that the population component of the definition was too vague. They commented that because Census figures were only updated every ten years, that high growth areas could be penalized, and that smaller clusters of dense population would not be included. The City wanted OPS to supplement the Census data with local data on utility connections. The City of Austin also stated that OPS incorrectly stated the Census Bureau's definition of an urbanized area.

USAs

The environmental component of the proposed high consequence area definition used OPS's recently proposed definition of Unusually Sensitive Areas (USAs) (64 FR 73464; Dec. 30, 1999).

Many commented that this proposed definition is too restrictive, and should be expanded to include all environmentally sensitive areas. EPA Oil Program Center expressed concern that OPS's methodology would fail "to protect even the most vulnerable of

sensitive environmental populations and their habitat." EPA Region III said that the definition should include product-specific differences. Friends of the Aquifer stated that "the rule proposes an eccentric and far too narrow definition of natural areas." AWWA also commented that the USA definition was inadequate because it excludes many sources of drinking water. Environmental Defense suggested we include all environmentally sensitive areas without the filtering system the proposed USA definition used. Friends of the Aquifer also wanted all environmentally sensitive areas included. Batten & Associates thought the proposed USA definition was too restrictive and would fail to protect many drinking water resources and habitats for threatened and endangered species.

Commercially Navigable Waterways

API and liquid operators questioned the inclusion of commercially navigable waterways into the high consequence area definition. API pointed out that Congress required OPs to identify hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists and once identified, issue standards, if necessary, requiring periodic inspection of the pipelines in these areas. API said that OPS had not determined the necessity for including these waterways in areas that trigger additional integrity protections. BP Amoco said the rule should be limited to protection of public safety, rather than commercial interests. Enbridge and Lakehead also questioned why waterways that are not otherwise environmentally sensitive should be included for protection.

EPA Region III said that we should also consider recreational and waterways other than those for commercial use. Environmental Defense, Batten, City of Austin and other commented that we should consider all navigable waterways as high consequence areas, because of the environmental consequences a hazardous liquid release could have on such waters.

Other Areas

EPA Region III maintained that product specific differences should be incorporated into the definition. Environmental Defense, Batten and other commenters wanted OPS to expand the definition of high consequence areas to include cultural, recreational, tribal and economic resources. Environmental Defense suggested we include national parks, wilderness areas, and wildlife refuges.

The City of Bellingham asked that we consider addressing integrity management programs for pipeline located outside the high consequence areas.

The City of Austin commented that the definition failed to include areas that are of high consequence due to preservation or recreational value alone. The City suggested including all state, national, and local parkland, refuges and wilderness areas, and preserves designated for water quality protection and wildlife.

API argued against expanding the definition to include cultural resources, environmental resources other than those identified as USAs, and other areas of national importance. They argued that including these areas would dilute available resources and focus from the populated and environmental areas that need greater protection, and that many other Federal, state, and local regulations are in place to minimize the effects of hazardous liquid pipelines on these other areas.

During discussions with representatives from DOJ/ENRD, DOI, and EPA, we were strongly urged to include other areas as high consequence areas: all waters of the United States, wetlands and wildlife refuges, wilderness areas, fish hatcheries, units of the National Park System, and wild and scenic rivers. DOI, DOJ and EPA strongly recommended that the National Parks and National Fish Hatcheries be included in the definition.

Identification of High Consequence Areas

API and liquid operators wanted OPS to clarify its commitment to identify high consequence areas, to generate and publish maps of the areas, and to periodically update the maps. These commenters said that such information was necessary before operators could assess pipelines and take appropriate preventive and mitigative measures.

Response: The final rule continues to focus on areas where we have determined a hazardous liquid pipeline failure could pose the greatest threat to public safety, unusually sensitive environmental areas (including drinking water and ecological resources), and water commerce that is essential for communities' safety and public health or for national security. We have not revised the definition to incorporate product-specific differences; rather, other parts of the rule address the risks associated with different products the pipeline is transporting (e.g., when considering risk factors for establishing assessment intervals).

Populated Areas

In the final rule, we have not changed the definition of populated areas that is based on the Census Bureau's definitions and delineations. We disagree that we misstated the Census Bureau's definition of urbanized areas. The only change we have made is in the terms we are using. What Census Bureau calls an *urbanized area*, we are calling a *high population area*. The additional populated areas that the Census Bureau calls a *census designated place*, we are calling an *other populated area*. We have chosen these definitions to avoid confusion over the term places, which the Census Bureau used to include both urbanized and census designated places. Our National Pipeline Mapping Systems (NPMS) will use the same titles and definitions used in this final rule.

We are using Census Bureau data for the population component because it is the recognized expert and source for general population data in the communities of the United States. The data are standardized, publicly available and in a format that allows OPS and others to create maps of the populated areas. OPS currently does not have the resources to gather local data on utility connections. However, nothing precludes an operator from supplementing the maps we will provide with other data pertinent to its pipeline. (As discussed later in this Preamble under the sub-topic heading "Identification of high consequence areas", an operator will have the ongoing responsibility to incorporate newly-identified populated areas and unusually sensitive environmental areas into its assessment plan.)

Populated areas consist of high population and other populated areas. High population areas are the Census Bureau's urbanized areas. These areas contain 50,000 or more people and have a population density of at least 1,000 people per square mile. Other populated areas are the Census Bureau's places minus the urbanized areas. These areas contain concentrations of people and include incorporated or unincorporated cities, towns, villages, or other designated residential or commercial areas.

We believe the population component of the high consequences area definition picks up most areas where pipelines can pose a threat to public safety. However, we are aware that there may be other areas where people congregate near pipelines, but do not fall within either sub-component of the population definition. Two recent and tragic accidents illustrate the dangers that

pipelines pose to public safety in these areas. In Bellingham, Washington, a pipeline release into a creek ignited and resulted in the deaths of three young people who were in the recreational park through which the creek flowed. An explosion that occurred on one of the three adjacent large natural gas pipelines near Carlsbad, New Mexico, killed 12 people, including five children, who had been camping near the pipeline.

Although this rule is not including areas where people congregate in the high consequence area definition, OPS is considering addressing these areas in a future rulemaking. In the meantime we encourage operators to consider addressing in their integrity management programs areas where people congregate and to determine if there are pipeline segments in or near these areas that could affect the area. Operators should be able to recognize these areas, through fly overs or other surveillance made of their pipelines, or through consultation with local officials in the community.

USAs

The rule's definition of high consequence areas will incorporate the final definition of Unusually Sensitive Areas, which OPS expects to issue in November 2000 (Docket No. RSPA-99-5455). The USA rulemaking will address the resolution of the above comments and other submitted to the docket for that rulemaking. Because of the dependence of this rulemaking on the final definition of USAs, this rule will not be effective until March 31, 2001.

Commercially Navigable Waterways

Our inclusion of commercially navigable waterways for public safety and secondary reasons is not based on the ecological sensitivity of these waterways. Parts of waterways sensitive for ecological purposes are covered in the proposed USA definition, to the extent that they contain occurrences of a threatened and endangered species, critically imperiled or imperiled species, depleted marine mammal, depleted multi-species area, Western Hemispheric Shorebird Reserve Network or Ramsar site. In this rule, only those pipeline segments that could affect a commercially navigable waterway are covered. We are including commercially navigable waterways as high consequence areas because these waterways are a major means of commercial transportation, are critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of

a national defense system. A pipeline release could have significant consequences on such vital areas by interrupting supply operations due to potentially long response and recovery operations that occur with hazardous liquid spills. As explained later, OPS will map these waterways on its National Pipeline Mapping System.

Other Areas

As discussed above, representatives of several Federal government agencies urged us to include other areas in the definition of high consequence areas. We have decided not to include these suggested areas in this rulemaking.

Although we have not included the other suggested areas in this rulemaking, we are considering extending protection to other environmentally sensitive and vital resources through future rulemaking. Other areas that will be considered include National Parks, National Wildlife Refuges, National Wilderness Areas, National Forests, and other cultural resources and sensitive environmental resources that do not meet the USA filtering criteria.

Identification of High Consequence Areas

OPS will identify high consequence areas on its National Pipeline Mapping System (NPMS). Operators, other government agencies and the public will have access to these maps through the Internet. Individuals will be able to view high consequence areas nationally or by state, county, zip code, or zooming in or out of a particular area. An operator will then be able to determine which of its pipeline segments intersect or have the ability to affect a high consequence area.

OPS will identify the locations of USAs through a comprehensive collection and analysis of drinking water and ecological resource data, contingent on the availability of funding and resources.³ OPS will make its USA maps, including the drinking water data, available through the National Pipeline Mapping System. Barring unforeseen resource demands, OPS's current plan is to have the USAs in the top ten states (covering 75% of total

pipeline mileage) available by the end of December 2000. Maps of the USAs in the next ten states (90% of total pipeline mileage) should be available by April 2001. And we plan to have the maps of the remaining states (100% of total pipeline mileage) available by December 2001.

Some of the information that OPS is purchasing, such as discrete sets of ecological data from the Nature Conservancy and other sources, will not be publicly available. Operators may need to contact resource agencies to obtain additional information on a particular species or drinking water intake in an USA.

OPS will use the National Waterways Network database to identify commercially navigable waterways. The commercially navigable waterways map and database will be available through the National Pipeline Mapping System. The Bureau of Transportation Statistics also has a database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website: <http://www.bts.gov/gis/ntatlas/networks.html>.

OPS will use the Census Bureau's data to identify high population and other populated areas. We will use the Census Bureau's urbanized area data to identify high population areas and their places data to identify other populated areas. Their data on places includes both urbanized areas and other populated areas. OPS will filter out the urbanized areas data from the places data so that the resulting map and database will clearly distinguish other populated areas from the urbanized or high population area data. Operators and the public will be able to view the high population and other populated areas maps together or separately on the National Pipeline Mapping System.

OPS recognizes that inventories and maps of high consequence areas have to be updated on a periodic basis to incorporate new information and databases. OPS intends to update the high consequence area maps every five years, contingent on the availability of funding and resources. OPS will review new or revised programs and databases at that time to incorporate appropriate programs and databases into the high consequence area definition and model. OPS will announce in the **Federal Register** and through other communication networks when revised high consequence area maps are available for given areas.

Changes, particularly population changes, will occur around an operator's pipeline. Although OPS intends to periodically update the maps, it remains

an operator's responsibility to keep information about its pipelines up to date. By continually evaluating its entire pipeline and analyzing all available information about the integrity of the pipeline, an operator should be aware of population and ecological changes that are occurring around the pipeline and continue to update its maps and integrity management program to accommodate these changes.

In the rule we have added requirements about how an operator is to incorporate any newly-identified high consequence areas into its baseline assessment plan and integrity program. The rule provides that when an operator has information (from the information analysis or from Census Bureau maps) that the population density around a pipeline segment has changed so as to fall within the definition 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. Similarly, an operator must incorporate a new unusually sensitive environmental area into its plan within one year from the date the area is identified. The rule further requires an operator to 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.

We thought it necessary to add these requirements because of the concerns many commenters expressed about who would be responsible identifying high consequence areas and how updates would be handled. Although OPS is taking primary responsibility for mapping these areas, an operator has a corresponding responsibility to continually evaluate its pipeline and update information about the pipeline.

8. Requirements for Preventive and Mitigative Measures, Including, Emergency Flow Restricting Devices (EFRDs) and Leak Detection Systems—Proposed Section 195.452(i)

The proposed rule required an operator to conduct a risk analysis to assess the risks to its pipeline system and determine what additional preventive and mitigative measures are needed to protect a high consequence area. The proposal identified possible preventive or mitigative measures an operator could take to protect a high consequence area, such as implementing damage prevention best practices, establishing or modifying leak detection systems, and providing additional training on response procedures.

³ OPS uses state data bases as the primary data source for the USA model. The drinking water USA model relies on data solely provided by the States. State aquifer maps are used to determine aquifer classifications. State data on well location depth, and source are used to identify the aquifers used by the wells. The ecological USA model uses data from the state Natural Heritage Programs (NHP) on rare and endangered species locations. OPS is also using the Environmental Sensitivity Index and related ecological data sets to augment the NHP data.

Installing EFRDs was one of several mitigative measures the rule proposed. However, the proposal did not require an operator to install EFRDs or define the conditions under which an operator should install EFRDs. In the NPRM we specifically invited comment on any needed further guidance to operators on when EFRDs should be installed. We also invited comment on the criteria for evaluating the decision on whether to install an EFRD or to take other measures, and if in certain limited circumstances, we should mandate the use of EFRDs.

EPA Region III supported the preventive and mitigative measures the rule proposed but argued against leaving the need for particular actions to the operator. Region III was concerned that without active and knowledgeable regulatory oversight, strict methodology, or the required participation of a risk assessment professional, an operator would be unlikely to find any of the measures necessary. Environmental Defense said that the rule should include specific requirements for operators to use preventive strategies. NTSB expressed concern with operators using risk management principles to determine the need for additional protective measures and recommended that the rule include minimum criteria.

EPA Oil Program Center said that the rule should prescribe circumstances in which EFRDs or other protective and mitigative measures must be used. EPA Oil Programs further commented that if the rule allows an operator to conduct a risk assessment to determine if EFRDs or other protective measures are needed, then the rule should prescribe a specific risk assessment protocol.

Environmental Defense, Batten and other advocates recommended that the rule include performance standards for leak detection, EFRD spacing and damage prevention best practices. Environmental Defense and Pipeline Survivor's Association recommended that leak detection systems be capable of detecting a leak of one gallon/minute or more and that EFRD spacing prevent releases of more than 10,000 gallons of hazardous liquid into a high consequence area. The City of Austin supported requiring EFRDs in all high consequence areas and that they be spaced to restrict the worst case spill to 10,000 gallons. Batten suggested that leak detection devices be capable of detecting within 15 minutes a leak of ten gallons or more and that pipe segments between EFRDs be able to contain no more than 50,000 gallons when located in a high consequence area.

AWWA encouraged the placement of EFRDs to the greatest extent possible to protect public water supplies, suggesting that EFRDs be used as the standard against which other mitigation strategies are measured. LCRA commented that EFRDs should be required on either side of a river crossing. EPA Region III also encouraged using EFRDs whenever necessary to protect a high consequence area.

API and operators commented that the proposed rule is reasonable and that OPS should ensure risk mitigation decisions made within an integrity management program include considering the use of EFRDs rather than requiring such placement or prescribing minimum spacing. Enbridge and Lakehead supported EFRDs as one of various preventive or mitigative actions an operator should consider but said there was no one distance or placement specification appropriate for all pipeline systems. Many cited research by the California State Fire Marshall, and Southwest Research to support their argument that there are many site and flow-specific factors that operators must consider in making risk mitigation decisions. Several industry commenters also noted the possible environmental disadvantage to EFRDs, including the possibility of valve leakage or inadvertent closure resulting in over pressurization, as well as the environmental impacts of installing and maintaining valves in or near environmentally sensitive areas.

Response: The final rule continues to require an operator to take additional measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. It is up to each operator to conduct a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. For this risk analysis, the rule clarifies that an operator must evaluate the likelihood of a pipeline release occurring, how a release could affect the high consequence area, and what risk factors the operator should consider. The rule continues to list some additional preventive and mitigative measures an operator should consider. The list is not an exhaustive recitation of every preventive or mitigative measure that could enhance public safety or environmental protection.

One of the listed measures is for an operator to modify the systems that monitor pressure and detect leaks. Operators use various procedures and methods to detect the movement of product through the pipeline. For

example, computational pipeline monitoring, SCADA systems, and station sensors, measure deviations from measured values (pressures, flows) beyond established norms. The pipeline safety regulations do not require an operator to have a leak detection system. However, if an operator has a software-based leak detection system, the regulations require the operator to use an industry document (API 1130) in designing, evaluating, operating, maintaining and testing its software-based system. (See § 195.444.) Moreover, whenever a leak detection system is installed or a component replaced, API 1130 must be followed.

The final rule requires an operator to have a means to detect leaks on its pipeline system. (We provide several examples of types of leak detection systems later in this document when we discuss Section 195.452(i).) We have rewritten the rule to require an operator to evaluate the leak detection's capability to protect the high consequence area and to modify, as needed, to protect the high consequence area. The rule includes factors that an operator must consider in making its evaluation. OPS enforcement personnel will review the adequacy of this evaluation process during site inspections.

Another protective measure the rule identifies is for an operator to install an EFRD on the pipeline segment. The final rule does not prescribe the specific conditions under which EFRDs or other preventive or mitigative measures are required. Rather, the final rule requires an operator to develop and apply risk assessment and decision-making processes that reflect pipeline-specific conditions and operating environments. The rule now specifies criteria that an operator must consider when conducting the analysis to identify additional protective measures. An operator is not limited to these criteria; rather, an operator must consider these criteria in addition to all other criteria specific to the pipeline segment.

In the final rule, OPS has not specified the circumstances when an operator must use a particular protective measure or install an EFRD. However, we have revised the rule to require that an operator install an EFRD if the operator determines that one is needed to protect the high consequence area. The rule also specifies factors that an operator must consider in making this determination. OPS will review during inspection the adequacy of the analysis and the appropriateness of the operator's decision on the need to install an EFRD.

OPS has been studying for some time the issue of the optimum placement of emergency flow restricting devices to limit commodity release after the location of the release has been identified. In the NPRM, we explained in detail the research OPS has conducted in this area. (See 65 FR 21695; April 24, 2000.) In addition to comment the NPRM solicited, OPS had previously issued an advance notice of proposed rulemaking asking questions concerning the performance of leak detection equipment and location of EFRDs, and held a public workshop to discuss the issues involved in developing regulations on EFRDs.

Our study of the issue led us to conclude that the decision to install an EFRD should not be mandatory but should be left to the operator. Nonetheless, the rule requires an operator to consider certain specified criteria in deciding whether an EFRD will protect the high consequence area.

OPS is requiring an operator to determine whether to install an EFRD based on the operator's risk analysis, because, we believe, prescriptive valve installation and spacing requirements would ignore the site-specific variables and unique flow characteristics of a pipeline segment. Prescriptive requirements could also overlook the potential sensitivity of a specific high consequence area. For example, locating an EFRD near a body of water to reduce the potential volume released might necessitate locating the valve in sensitive wetlands or a flood plain of a river, which creates myriad other problems. Also, a prescriptive approach detracts from the process of evaluating a host of alternative measures to enhance protection to high consequence areas.

9. Methods To Measure Program's Effectiveness—Proposed Section 195.452(k)

In the NPRM we proposed that an operator's integrity management program include methods to measure whether the program is effective in assessing and evaluating the integrity of the pipelines and in protecting the high consequence areas. NTSB commented that this requirement has to contain unequivocal guidance if operators are to use it to improve their programs, and suggested that we develop measures. EPA Region III commented that a measurement based on some industry-wide average should not be used because it could lower the bar for management, technology, and innovation.

Response: We have not revised the provision on program performance

measures other than to clarify that an operator is to measure the effectiveness of the program on each pipeline segment. In Appendix C we have described types of program measures and included examples of methods that an operator can use to evaluate the effectiveness of its integrity management program.

10. Cost Benefit Analysis

The comments we received on the proposed rule's cost benefit analysis are addressed below under the Regulatory Analyses and Notices section.

11. Information for Local Officials and the Public

In the NPRM, OPS invited comments on how local officials could use and benefit from risk assessment information, how the consequences of potential pipeline failures should be characterized, how risk control actions should be described and what performance indicators would be meaningful. We further said that because of the significance of this issue we planned on extensive discussions with all the stakeholders before proposing communications requirements as part of an integrity management program.

Many provided comments relevant to the issue of communications with local officials. Tosco agreed that research is needed on the types and amount of information to distribute to local officials and made available to the general public to determine the most effective means to keep those entities informed. Environmental Defense, the Pipeline Survivor's Association, and Batten listed information they thought operators should make available to public officials and the public. American Water Works Association strongly supported the need for communication, but provided no specific guidance on content.

Lower Colorado River Authority (LCRA) promoted public involvement in the preparation and implementation of integrity management programs, maintaining that with public involvement, pipeline operators would have a better understanding of the vulnerability of the resources. LCRA further commented that public confidence in the pipeline industry would be enhanced if the results of the integrity assessments were made available. The City of Bellingham also recommended that integrity management programs be developed in consultation with appropriate state and local officials before the operator finalizes the program. The National Pipeline Reform Coalition also

recommended that local communities have a role in developing the programs, citing the evidence of the role of the City of Bellingham in developing a safety plan for Olympic Pipe Line Company.

Response: Requirements for communication of integrity management information to local public officials and to the public will be the subject of a future rulemaking. We will use the comments received in this rulemaking in developing the communications rulemaking. A communications work team, consisting of representatives from environmental and public safety organizations, pipeline companies, and government has formed to aid the Hazardous Liquid Advisory Committee (THLPSSC) in developing communications issues. Notices of meetings of the work group will be published in the **Federal Register**. Notes from the meetings will be posted on OPS's web site.

12. Appendix C Guidance

Proposed Appendix C provided operators guidance on how to prioritize risk factors in determining assessment frequency, how to analyze smart pig inspection results, how to prioritize metal loss features, and what types of smart pigs to use for finding pipeline anomalies. The proposed Appendix also included risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, to help determine if the pipeline segment falls into a high, medium or low risk category.

There were a variety of comments concerning Appendix C. Some addressed the role of Appendix C in the overall rule, and others provided specific technical comments on detailed aspects of the Appendix (which are not summarized here).

API and other liquid operators commented that Appendix C "is not sufficiently rigorous or technically accurate to be used as guidance for prioritizing risk" and provided a list of problems they have identified. API recommended that OPS not include the Appendix in the final rulemaking, but that OPS and the integrity standard work group develop technically accurate, rigorous guidance for prioritizing risk factors.

The City of Austin recommended that Appendix C be included as part of the rule because it specifies how an operator should implement the proposed regulation. Fuel Safe Washington stated that "Appendix C is completely undermined by allowing operators to apply their own weights or values to the risk factors."

Response: An Appendix is guidance that is intended to give advice to operators on how to implement the requirements of the integrity management rule. An Appendix does not have the same force as the regulation itself. An operator does not have to follow the guidance. However, if an operator incorporates parts of the Appendix into its integrity management program, an operator must then comply with those provisions.

OPS continues to believe that the guidance provided in Appendix C will be helpful to operators in developing and implementing their integrity management programs. (Operators may supplement this guidance with the industry consensus standard or choose not to use the guidance.) We also continue to believe that the guidance should not be included in the body of the rule because it would unnecessarily inhibit operators from identifying the best pipeline- and segment-specific tools, risk factors, and repair techniques, and would require changes in the rule as new technologies or information is developed.

The Final Rule

The new section 195.450 titled "Definitions" defines high consequence areas. High consequence areas include—

- Unusually sensitive areas—these areas will be defined in the USA rulemaking (Docket No. RSPA-99-5455) and will include drinking water and ecological resources;
- High population areas—these are areas defined and delineated by the Census Bureau as urbanized areas.
- Other populated areas—these are areas defined and delineated by the Census Bureau as places that contain a concentrated population.
- Commercially navigable waterways—these are waterways where a substantial likelihood of commercial navigation exists.

The integrity management program requirements will apply to pipeline segments that could affect these high consequence areas. OPS will map these areas on its National Pipeline Mapping System, and make the maps publicly available.

This section also defines emergency flow restricting devices to include check valves and remote control valves. This definition is used in § 195.452(i) of the rule that addresses additional preventive and mitigative measures an operator must consider for pipeline segments that could affect a high consequence area.

The new section 195.452 titled "Pipeline Integrity Management in High Consequence Areas" imposes integrity

management program requirements on each operator who owns or operates a total of 500 or more pipeline miles used in hazardous liquid transportation.

For an operator covered by the rule, the rule requires the operator to develop, implement and follow an integrity management program that provides for continually assessing the integrity of those pipeline segments that could affect a high consequence area, through internal inspection, pressure testing, or other equally effective assessment means. An operator's program must also provide for evaluating the segments through comprehensive information analysis, remediating potential integrity problems found through the assessment and evaluation, and ensuring additional protection through preventive and mitigative measures.

Through this required program, a hazardous liquid operator must comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the entire pipeline and its relevance to the segment that could affect a high consequence area. Information an operator must evaluate includes information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The final rule requires an operator to take prompt action to address all integrity issues raised by the integrity assessment and information analysis. This means an operator must evaluate all anomalies and repair those could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the anomalies for evaluation and repair. The schedule must include time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also maintain, and further protect the integrity of these pipeline segments, through other remedial actions, and preventive and mitigative measures.

Which Operators Must Comply? Section 195.452(a)

This rule specifies pipeline system integrity management program requirements for each operator who owns or operates a total of 500 or more miles of hazardous liquid pipeline. This action covers approximately 87 percent

of all the hazardous liquid pipelines in the United States. Based on the volume of hazardous liquid these pipelines transport, they have the greatest potential to adversely affect the environment.

For an operator covered by this rule, the requirements apply to all the operator's pipeline segments (offshore or onshore), regardless of date of construction, that could affect a high consequence area. The rule specifies how operators must provide additional protection to critical areas (*i.e.*, high consequence areas) through integrity management programs. Further, it assures that these protections will be put in place, with an operator being required to initially assess 50 percent of the line pipe that could affect critical areas, beginning with the highest risk pipe, within 3.5 years and the balance within seven years. An operator will then have to evaluate and repair defects within specified time frames and implement additional preventive and mitigative measures. An operator is also required to continually re-assess its pipeline segments at intervals not longer than five-years, as well as periodically evaluate each pipeline segment by analyzing all available information about the integrity of the entire pipeline, and its relevance to segments that could affect the high consequence areas.

What Must an Operator Do? Section 195.454(b)

The rule requires that, no later than one year after the rule's effective date, an operator must develop a written integrity management program that addresses the risks on each pipeline segment that could affect a high consequence area. An operator must then implement and follow the program it has developed. Initially, the program will consist of a framework. An operator must include in its integrity management program—

- An identification of all pipeline segments that could affect a high consequence area. Because identification of the pipeline segments is the trigger for all other integrity management requirements, the identification must be done within nine months from the rule's effective date.
- A plan for baseline assessment. The assessment of the line pipe must be done by internal inspection, pressure test, or other technology that provides an equivalent understanding of the condition of the line pipe.

- A program framework that addresses each of the required program elements, including continual integrity assessment and evaluation. In the first year after the rule's effective date, the

framework must indicate how decisions will be made to implement each required program element. The framework will evolve into an integrity management program as the operator makes decisions and gains experience. An integrity management program is a dynamic program that an operator must continually change as the operator gains more information about the pipeline and the results of the assessments.

To carry out the rule's requirements, an operator must follow recognized industry practices unless the rule specifies otherwise or the operator chooses an alternative practice that is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection. Recognized industry practices include national consensus standards and practices found in reference guides. Allowing the use of alternative practices in the rule should encourage operators to use innovative technology in implementing the integrity management program's requirements.

What Must Be in the Baseline Assessment Plan? Section 195.452(c)

The rule requires an operator to include in its written baseline assessment plan each of the following elements.

- The methods selected to assess the integrity of the line pipe of each segment that could affect a high consequence area;
- A schedule for completing the integrity assessment;
- An explanation of the assessment methods the operator selected and an evaluation of risk factors the operator considered in establishing the assessment schedule for the pipeline segments.

The rule allows an operator to modify the baseline assessment plan provided the operator documents the modifications and reasons for the modifications. As discussed later under the section on recordkeeping requirements (§ 195.452(l)), these are documents an operator is required to maintain for inspection. Enforcement personnel will look to see that an operator has documented the modification well before the operator has implemented the modification.

OPS expects an operator to make the best use of current and innovative technology in assessing the integrity of the line pipe. Therefore, the rule allows an operator to conduct an integrity assessment by—

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents,

gouges and grooves. For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures, the rule provides that the integrity assessment methods must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. An operator's program would also have to address any risk factors associated with these types of pipe;

- Pressure test conducted in accordance with Part 195, subpart E; or
- Other technology that provides an equivalent understanding of the condition of the line pipe.

Internal inspection is one of the most useful tools in an integrity management program. We expect an operator to consider at least two types of internal inspection tools for the integrity assessment of the line pipe: *geometry pigs* for detecting changes in circumference and *metal loss tools* (magnetic flux leakage (MFL) pigs or ultra sonic pigs) for determining wall anomalies, or wall loss due to corrosion. Both high resolution and low resolution tools can be beneficial in integrity assessment. For example—

Corrosion/metal loss: With respect to corrosion, high-resolution tools can identify anomalies and, with the use of engineering critical assessments, use a conservative evaluation of the potential for the anomaly to have affected remaining pipe strength (or affected the pressure capacity of the pipeline segment). This assessment uses analytical techniques that estimate average depth of metal loss. Based on the evaluation of internal inspection results, a prioritized listing of potential defects is developed to guide the initiation of the field digging, inspection, confirmation and the necessary repair program. Once in the field, additional calculations based on actual profile of metal loss are used to confirm the need and type of appropriate repair.

High Resolution versus Low Resolution: High-resolution tools can distinguish between internal and external corrosion and provide more extensive information to more accurately assess the potential for an anomaly to pose a risk.

Mechanical Damage: Internal inspection tools to measure dents or geometric deformations are common and are typically run routinely following installation of new pipelines. Technology has advanced such that geometry tools can normally withstand even the most extreme pipeline conditions. The tool is able to pass restrictions (e.g., deformations) of up to 25%, and with the high sensitivity of

gauging systems now on the market and large number of sensing fingers, current tools can detect even very small ovalities (0.6%).

Crack Detection: Since the early 1990's, pipeline operators have successfully field tested internal inspection tools capable of non-destructively identifying fatigue cracks and stress corrosion cracking in the longitudinal seam. Research and development continues on these tools to strive for reliable identification of other types of seam defects, such as hook cracks. With the use of ultrasonic and MFL (transverse orientation) technology, pipeline segments that have experienced fatigue cracking can now be inspected. Cracks with a potential to rupture can be identified and repaired prior to growing to a critical stage. This is particularly important as this type of defect could survive initial and subsequent pressure tests but then with pressure cycling, grow over time to a critical stage and leak or rupture.

The rule also permits integrity assessment of the line pipe by pressure test. An operator must conduct a pressure test according to the requirements prescribed in Part 195, subpart E.

The purpose of a pressure test is to remove defects that might impair the integrity of the pipeline during operation. Defects might exist as a result of the manufacturing process or damage to the pipe during shipping, construction or operation. The defects are identified by failure of the pipe during the test, the defective pipe is removed, new pipe is installed, and the pipe is tested again until no failure occurs. The pressure test provides a margin of safety for the pipeline by being conducted at a pressure higher than the maximum pressure at which pipeline safety regulations allow the pipeline to be operated.

OPS expects that an operator choosing this method of integrity assessment for a pipeline segment will review its corrosion control monitoring program for that segment. OPS inspectors will review these documents when evaluating an operator's choice of pressure test as an assessment method.

To encourage innovation, the final rule also allows an operator to use other technology for the integrity assessment, if the operator demonstrates that an alternative technology can provide an equivalent understanding of the condition of the line pipe as the other permitted assessment methods.

An operator choosing this option must notify OPS at least 90 days before conducting the assessment with the other technology. The rule specifies

how notification can be made: by mail or facsimile. Advance notice is necessary so that OOPS enforcement personnel have adequate time to review the operator's basis for using the technology.

When Must the Baseline Assessment Be Completed? Section 195.452(d)

The rule requires an operator to establish a baseline assessment schedule to determine the priority for assessing the pipeline segments covered by the rule. An operator must complete the baseline integrity assessment within seven years after the rule's effective date. An operator is further required to assess at least 50% of the covered line pipe, beginning with the highest risk pipe, within 3.5 years from the rule's effective date. This requirement, in conjunction with the requirement to base the assessment intervals on risk-based factors, should ensure that an operator assesses the highest risk pipeline segments earlier in the cycle.

The final rule allows an operator to use an integrity assessment method conducted five years before the rule's effective date as the baseline assessment if the method is at least equivalent to the requirements for internal inspection, pressure testing or alternative technology. However, if an operator decides to use a prior integrity assessment as its baseline assessment, the operator must then re-assess the integrity of the line pipe within five years. The re-assessment would have to comply with the continual integrity assessment requirements in § 195.452(j). As we discuss later in this document when explaining § 195.452(j), the rule allows for deviations from the five-year requirement in certain limited instances.

Because population and ecological changes may occur around an operator's pipeline, an operator must, as part of its periodic evaluation and information analysis, keep informed about how such changes are affecting each pipeline segment. If the population density around a pipeline segment changes so as to fall within the definition of a high population area or another populated area, the rule requires an operator to incorporate the area into its baseline assessment plan as a high consequence area. This must be done within one year from when the area is identified. An operator must then assess the integrity of any line pipe that could affect that newly identified high consequence area within five years from when the area is identified. Similarly, the rule requires an operator to incorporate a new unusually sensitive environmental area into its baseline plan within one year

from when the area is identified and to assess the new area within five years.

What are the Risk Factors for Establishing an Assessment Schedule? Section 195.452(e)

For both the baseline and continual integrity assessments, an operator must establish a schedule that prioritizes the pipeline segments for assessment so that the higher risk segments are assessed earlier in the cycle. The rule requires an operator to base the assessment schedule on all risk factors that reflect the risk conditions on each pipeline segment. The rule further specifies some factors an operator must consider in establishing a schedule. An operator is not limited to these factors; rather, an operator must supplement the listed factors with those that are specific or unique to the pipeline segment being assessed.

In Appendix C, we provide guidance to an operator on how to determine risk factors for a pipeline segment and use them to develop an integrity assessment schedule. The guidance includes an example of risk factors that we apply to a hypothetical pipeline segment to establish an assessment frequency.

What Are the Elements of an Integrity Management Program? Section 195.452(f)

The final rule requires an operator to include certain minimum elements in its integrity management program. Initially, an operator must develop a framework containing these elements. The framework evolves into a program as the operator gains experience, makes decisions and implements actions. The required program elements include—

- A process for identifying which pipeline segments could affect a high consequence area. The Appendix gives guidance to help an operator evaluate how a pipeline segment could affect an area, which will help an operator in developing this process. The guidance lists factors an operator needs to consider when evaluating the pipeline segment's ability to affect a high consequence area.
- A baseline assessment plan (discussed in § 195.452(c));
- An analysis that integrates all available information about the integrity of the entire pipeline, its relevance to the particular segment, and the consequences of a failure;
- Criteria for repair actions to address integrity issues raised by the assessment methods and information analysis;
- A continual process of assessment and evaluation to maintain a pipeline's integrity;

- Identification of preventive and mitigative measures to protect the high consequence area;

- Methods to measure the program's effectiveness; and

- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information. An operator must use qualified persons with the necessary technical expertise to evaluate and analyze the results and data from the integrity assessments, the periodic evaluation, the information analyses, etc.

To be effective, an integrity management program must constantly change. OPS expects that the initial program will consist of a framework that specifies the criteria for making decisions to implement each of the required elements. The program evolves from the framework and must continue to change 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.

What is an Information Analysis? Section 195.452(g)

The final rule requires an operator to periodically evaluate the integrity of each pipeline segment that could affect a high consequence area by analyzing all available information about the integrity of the entire pipeline and the consequences of a failure. The analysis applies to the entire pipeline to determine the relevance to a particular pipeline segment. Required information an operator must evaluate includes—

- 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;
- Data gathered through the required baseline and continual integrity assessments;
- Data gathered in conjunction with other inspections, tests, surveillance and patrols required in Part 195. This would include information from corrosion control monitoring and cathodic protection surveys;
- Information about how a failure would affect the high consequence area, such as location of the water intake.

Through this requirement to integrate and analyze information from diverse sources, OPS expects an operator to analyze its entire pipeline to evaluate the entire range of threats to each pipeline segment that could affect a high consequence area. An operator will

conduct this analysis in conjunction with the required periodic evaluation discussed below (section 195.452(j)).

What Actions Must Be Taken To Address Integrity Issues? Section 195.452(h)

The rule requires an operator to take prompt action to address all pipeline integrity issues raised by the integrity assessment and information analysis. By prompt action we mean that an operator must prioritize repairs according to the severity of the anomaly and address first those anomalies that pose the greatest risk to the pipeline's integrity. The rule clarifies that an operator must evaluate all anomalies and repair those that could affect the pipeline's integrity. Any repair made must be done according to the pipeline repair requirements in 49 CFR § 195.422.

The rule requires that an operator develop a schedule that prioritizes the anomalies found during the integrity assessment and information analysis for evaluation and repair. In this schedule, an operator would have to provide for prompt review and analysis of the integrity assessment results by a date certain. For the first three years after the rule's effective date, an operator would determine the period by which the results would have to be reviewed and analyzed and commit to that date in its schedule. After the third year, an operator's schedule must provide for reviewing and analyzing the results of the integrity assessment within 120 days of conducting the assessment.

An operator's schedule also has to provide time frames for evaluating and completing repairs. The rule provides that an operator is to base the schedule on specified risk factors and pipeline-specific risk factors the operator develops. For conditions not specified in the rule and those the rule identifies as other conditions, the operator determines the schedule for evaluation and repair. However, the rule provides the time frames in which an operator must complete repair of certain conditions on the pipeline. These conditions are listed as immediate repair conditions, 60-day conditions and 6-month conditions. Of course, the rule cannot identify all conditions that an operator will have to evaluate and repair. A condition an operator discovers may qualify as an immediate repair, 60-day or 6-month condition even though it is not listed in the rule. The rule simply provides common examples of such conditions.

The schedule required for repair starts at the time the operator discovers the condition on the pipeline, which occurs when an operator has adequate

information about the condition to determine the need for repair. Depending on circumstances, an operator could have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly or, receives the final internal inspection report.

An operator may deviate from the rule's specified repair times (immediate repair, 60-day, 6-month) if the operator justifies the reasons why the schedule cannot be met and that 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. (See section 195.452(l).) An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made. The operator would have to provide OPS 90-days notice by mail or facsimile.

What Preventive and Mitigative Measures Must an Operator Take To Protect the High Consequence Area? Section 195.452(i)

The final rule requires an operator to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. An operator must conduct a risk analysis of each pipeline segment to identify additional actions to enhance public safety or environmental protection. The rule lists some additional preventive or mitigative measures an operator needs to consider for the pipeline segment, including installing emergency flow restricting devices and modifying the leak detection systems. An operator is not limited to the listed measures but should also identify additional protective measures not listed.

The rule requires that, in identifying the need for additional preventive and mitigative measures, the operator evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. An operator must consider all relevant risk factors in making this determination; the rule lists some that an operator must consider. An operator is to supplement the listed risk factors with any other factors specific or unique to the pipeline segment. Listed factors include—terrain surrounding the pipeline, including drainage systems such as small streams and other smaller waterways that could act as a conduit to

the high consequence area; elevation profile; characteristics of the product transported; amount of product that could be released; possibility of a spillage in a farm field following the drain tile into a waterway; ditches along side a roadway the pipeline crosses; physical support of the pipeline segment such as by a cable suspension bridge; and exposure of the pipeline to operating pressure exceeding established maximum operating pressure. In addition, Appendix C to the rule provides an operator with further guidance on evaluating how each pipeline segment could affect a high consequence area.

Leak Detection

The final rule requires an operator to have some means to detect leaks on its pipeline system. The rule further requires an operator to evaluate the capability of its leak detection means and modify the capability, as necessary, to protect the high consequence area.

The rule lists factors that an operator must consider when making this evaluation. Again, the list is not exclusive. It is simply a starting point that an operator must supplement with factors relevant to each pipeline segment being evaluated.

Some examples of leak detection systems include—

Dynamic flow modeling: This model simulates the operating conditions of the pipeline through hydraulic calculations, then compares the computed pressures (based on flow rate, temperature, pipe profile, and density) against real time data obtained from various measuring points along the pipeline. Deviations are compared against alarm set points. When the deviations exceed the set points, the system alarms. These systems are normally integrated with the pipeline SCADA communications technology. Leak location information is not provided.

Tracer chemical: This approach requires mixing a very small amount (ppb to ppm of total volume) of a specific volatile chemical tracer with the contents of a pipeline. The chemical tracer is not a component of the pipeline contents and does not occur naturally in the soil. After the pipeline is inoculated with the tracer chemical, samples of the vapor contained in the soil outside the pipeline are collected. The soil vapor samples are obtained from probes or other devices installed intermittently along the pipeline. The vapor samples are analyzed by a gas chromatograph for the specific tracer chemical that was mixed with the pipeline contents. Presence of the tracer chemical in the

sample can only occur through an active release of pipeline product mixed with the tracer into the soil. These systems are able to provide single or continuous liquid tightness tests and will provide release location information.

Release Detection Cable: Release detection sensing cables are designed to alarm after contact with liquid hydrocarbons at any point along their length. The presence of hydrocarbons creates a circuit between two sensing wires and triggers an alarm. Typically, leak detection cable is installed in slotted PVC conduit that is buried in the pipe trench along or below the pipeline. These systems provide continuous monitoring via electronic control units capable of interfacing with SCADA technology and are able to provide leak location information.

Shut-in (static) released detection: This technique consists of a pressure test, with the pipeline filled with its normal contents. Between shipments, the pipeline is pressured against a closed valve(s). This release detection tool allows the operator to analyze the pipeline in a static (no flow) mode, without the complications of dynamic modeling. With the pipeline blocked, the pressure (compensated for temperature fluctuations) in a section should remain constant. The pressure is then monitored for any unexplained pressure losses. This test does not provide leak location information.

Pressure point analysis release detection software: Software for this system incorporates two independent methods of release detection: pressure point analysis and mass balance. Pattern recognition algorithms that distinguish normal operating events from leaks are used. With an appropriate communications system, this system can provide the calculated location of a release.

Emergency flow restricting devices (EFRDs)

The rule requires an operator to install an EFRD if the 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. The rule lists certain factors that an operator must consider in making this determination, to be supplemented with other factors the operator determines are relevant to the pipeline segment being evaluated. Listed factors an operator must consider include 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 and the high consequence area, and benefits expected by reducing the spill size.

Installing an EFRD on a pipeline segment is only one of several possible preventive or mitigative measure that an operator can take to provide additional protection to a high consequence area.

What is a Process for Continual Evaluation and Assessment to Maintain a Pipeline's Integrity? Section 195.452(j)

The integrity assessment requirements do not stop with the baseline integrity assessment. An operator must continue to assess the integrity of the line pipe and evaluate the integrity of each pipeline segment that could affect a high consequence area. The rule requires an operator to conduct a periodic evaluation of each pipeline segment, as frequently as needed, to assure the pipeline's integrity. An operator would determine frequency based on specified risk factors plus other factors specific to the pipeline segment.

The evaluation is based, in part, on the information analysis the operator has made of the entire pipeline to determine what history and operations elsewhere could be relevant to the segment. The evaluation must also consider the past and present integrity assessment results, and decisions about repair, and preventive and mitigative actions. The evaluation must be done by a person qualified to evaluate the results and other related data.

As with the baseline assessment, the continual integrity assessment method must be by internal inspection, pressure test, or other technology that provides an equivalent understanding of the condition of the line pipe. As with the baseline assessment, if an operator chooses other technology as a re-assessment method, the operator must give 90-days advance notice (by mail or facsimile) to OPS.

An operator must conduct the integrity re-assessment at intervals not to exceed five years, except in those limited instances where the operator can clearly justify an extended interval. The rule requires that an operator base the continual 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 using specified risk factors (supplemented by risk factors relevant to the pipeline segment), the information analysis, and

analysis of the results from the last integrity assessment.

The rule recognizes limited exceptions to the five-year period.

- An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The operator must support the justification by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technologies. An operator would also have to demonstrate that the other technology would provide an understanding of the line pipe equivalent to that obtained by an assessment conducted at an interval of five years or less.

- The other exception is that an operator may not be able to conduct an integrity assessment on a segment of pipe within the required period because sophisticated internal inspection devices or other technology is not available. An operator must justify the reasons why it cannot comply with the required assessment period of not more than five years and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim.

In either instance, the operator must inform OPS of its proposed variance from intervals of not more than five years. A 90-day advance notice before the end of intervals of not more than five years is needed if the operator will require a longer assessment interval because sophisticated technology is not available. If the operator is justifying a longer assessment interval on an engineering basis, notice must be given nine months before the end of the interval of five years or less.

- The engineering-based exception has been included in the rule to encourage the use of advanced alternative technologies. It is intended for use in those instances where an operator is employing an advanced alternative technology and should therefore be dictated by the use of such technology. It is intended to be a limited exception to the interval of five years or less and not to exceed an additional two years whenever possible.

What Methods To Measure Program Effectiveness Must Be Used? Section 195.452(k)

The final rule requires that an operator include in its integrity management program 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. Because performance measures must be tailored to an individual

program, the rule does not specify the measures an operator has to include.

However, in the Appendix C to this rule we have provided guidance on performance measures. The guidance also gives examples of categories of performance measures that an operator should consider. Examples of measures that an operator could adapt for its program include—

- Selected Activity Measures—Measures that monitor the surveillance and preventive activities the operator has implemented.
- Deterioration Measures—Operation and Maintenance trends that indicate when the integrity of the system is weakening despite preventive measures.
- Failure Measures—Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.
- Internal vs. External Comparisons. Comparing data that could affect a high consequence area with data from pipeline segments in other areas of the system, and comparing data external to the pipeline segment.

What Records Must Be Kept? Section 195.452(l)

The final rule requires that an operator maintain certain records for inspection, including its written integrity management program. This requirement is not any different from the procedural manual an operator is required to maintain for operations, maintenance and emergencies. An operator would also be required to maintain for review during inspection documents that support the decisions and analyses made, and actions taken to implement and evaluate each element of the integrity management program. This would also include records documenting any modifications, justifications, variances, deviations and determinations made. Again, this requirement is no different from the myriad documents an operator now maintains to comply with the other provisions of the pipeline safety regulations.

The rule cannot possibly list all records that an operator would have to maintain to demonstrate its compliance with the integrity management program requirements. Appendix C provides examples of some documents that an operator would need to maintain for inspection. The list is not exhaustive. Listed examples include:

- Record identifying all pipeline segments that could affect a high consequence area;
- Baseline assessment plan that includes each required plan element;

- Modifications to the baseline assessment plan and reasons for the modifications;
- Use of and support for alternative practices;
- An integrity management program framework that includes each of the required program elements, updates and modifications to the initial framework and eventual program;
- Process for establishing the baseline and continual re-assessment intervals;
- Process for identifying population changes around a pipeline segment;
- Any variance from the required re-assessment intervals, and reasons for the deviation;
- Results of the baseline and continual integrity assessments;
- Results of the information analyses and periodic evaluations;
- Process for integrating and analyzing information about the integrity of a pipeline;
- Process and risk factors used for determining the frequency of periodic evaluations;
- Schedule for reviewing and analyzing integrity assessment results;
- Schedule for evaluating and repairing anomalies found during the integrity assessment;
- Any deviation from the required repair schedule for the listed conditions;
- Criteria for repair actions; records of anomalies detected actions taken to evaluate and repair the anomalies;
- Records of other remedial actions planned or taken;
- Risk analysis to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;
- Criteria and process for determining EFRD installation;
- Criteria and process for evaluating leak detection capability;
- Program performance measures.

Appendix C

We are adding a new Appendix C to Part 195. This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule. An operator is not required to use this guidance. The Appendix contains guidance on—

- Information an operator may use to identify a high consequence area and factors an operator may use to consider the potential impacts of a release on a high consequence area;
- Risk factors an operator may use to determine an integrity assessment schedule;
- 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.

- Types of internal inspection tools an operator may use to find pipeline anomalies;
- Measures an operator could use to measure an integrity management program's performance; and
- Types of records an operator will have to maintain.

Regulatory Analyses and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) considers this action to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993). Therefore, it was forwarded to the Office of Management and Budget. This final rule is significant under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979).

Consideration of Public Comments

We received a number of comments that related to the draft Regulatory Evaluation that accompanied the proposed rule (65 FR 21695). OPS has considered those comments and has made changes in this evaluation where appropriate. Provided below is a summary of the comments and any changes made to the Regulatory Evaluation.

1. *Costs for Developing Integrity Management Programs.* Commenters suggested that the costs for developing integrity management programs were underestimated. The comments suggested that integrity management programs can cost \$75–\$300 thousand, rather than the \$25–\$75 thousand range used in the draft evaluation. OPS acknowledges that its estimate of the costs to prepare integrity management programs may have been too low. OPS has used the suggested range in this evaluation. OPS has continued to assume that 10 percent of the operators covered by the rule (those who own or operate 500 or more miles of hazardous liquid pipeline) will have already developed company-specific integrity management programs. Operators' costs to develop these programs have already been expended; operators will incur no further costs as a result of this rule. OPS has revised the estimated cost that will be incurred by the remaining 90 percent of covered operators for developing programs to \$100 thousand. (It is assumed that the programs operators develop that comply with the final rule will be less costly than the comprehensive programs that some operators have developed voluntarily.)

2. *Costs for Periodic Update and Documentation.* Commenters also suggested that the costs for periodic program updates and documentation (called "reports" in the draft evaluation) were underestimated. They estimated a range of \$50–150 thousand for this work. OPS agrees that the estimate in the draft evaluation was unrealistically low. In that evaluation, the only documentation considered was records of assessments, which were assumed to be produced by lower level personnel under general supervision. The draft evaluation failed to consider the need to evaluate whether changes to the program are needed, because technology or the pipeline changes or because high consequence areas are redrawn (as they will be periodically), and to make those changes. Operators will expend resources to evaluate these things, even if few changes are made. This will add costs. No update or changes will be required in some years, when the only expense will be to consider new information to ascertain whether an update is needed. OPS cannot accept, however, the presumption that the range of such annual costs will significantly overlap the range of costs to develop the programs in the first place, as suggested by the comment. Significantly less work is involved in updating an existing program. For purposes of this evaluation, OPS included the need to update an integrity management program. Costs for this effort were estimated at \$8,000 per year, which is considered reasonable compared to the estimated cost for developing the program initially. Routine documentation is estimated at \$2,000 annually, an increase of a factor of two from the estimate included in the draft evaluation. The net annual cost for updates and documentation is thus \$10,000 per operator or \$660 thousand in total.

OPS also included in this final evaluation costs for data integration. These costs will include a need to realign company-internal data management systems in the first year and continuing costs for the professional review of the integrated data related to the integrity of pipelines in high consequence areas. OPS has estimated costs for these activities at \$50,000 per operator in the first year after the rule (when internal data management realignment will occur) and \$25,000 per year thereafter.

3. *New Assessment will be Required.* Commenters disagreed with the assumption in the draft evaluation that no additional integrity assessment would be required, since operators were conducting internal inspection and

pressure testing at a rate sufficient to complete all required baseline assessment in the first seven years after the effective date of the rule. The total number of affected pipeline miles has also increased since the proposed rule. Because of these changes, OPS agrees that integrity assessment of the number of pipeline miles affected by the final rule will require an increase in the rate of assessment represented by recent industry practice. OPS continues to assume that initial assessment would have proceeded at the current rate if there were no rule. OPS has estimated costs for assessment that will be required above that rate to assure that all affected pipeline is assessed in the seven years following the effective date of the rule.

4. *Need for More Detailed Cost-benefit Analysis.* Commenters, including the Technical Hazardous Liquid Pipeline Safety Standards Committee (Advisory Committee), contended that the Regulatory Evaluation is not consistent with the OPS framework for cost-benefit analyses or in conformance with applicable standards. They suggested that OPS perform a more rigorous evaluation, perhaps in parallel with the rulemaking. They recommended that the suggested analysis quantify the benefits of the proposed rule, which was not done for the draft evaluation. The Advisory Committee unanimously voted that the Cost-Benefit Analysis was not sufficient. Commenters also cited failure to identify a specific target problem.

OPS has revised the regulatory evaluation to more closely follow the form of the framework. This included identifying the target problem. OPS agrees with the concerns of the Advisory Committee and other commenters but notes that it does not have adequate data on pipeline spills to accurately gauge the benefits of this rule. The DOT Inspector General, in its audit report, "Pipeline Safety Program Report No. RT-2000-069, March 12, 2000, stated, "OPS accident database contains inaccurate causal information and underestimates property damage." These problems make it difficult to prepare a more rigorous analysis. OPS has done some further research to examine the availability of additional data. OPS turned to data from the National Oceanographic and Atmospheric Administration (NOAA), the lead Federal Agency on quantifying the costs of hazardous liquid spills.

In their paper, *Putting Response and Natural Resource Damage Costs in Perspective*, Douglas Helton and Tony Penn, employees of NOAA, wrote that, "[t]he total private and social cost of oil spills is of great interest to industry,

responders, and regulators, but relatively few incidents have been examined in detail. Furthermore, publicly available cost data are often limited to State and Federal response costs and natural resource damages. Significant categories of costs, such as private response costs, third party claims, and vessel or facility repair costs, are often not publicly available." The authors further warn that, "[w]hen cost estimates are reported, they should be considered partial and spill volumes should be viewed with some skepticism." They conclude that, "[f]ailure to consider these additional cost categories because of unavailable data may result in erroneous conclusions regarding the total cost of spills and the significance of any one category."

Helton and Penn studied 48 spills between 1984 and 1997. (Note that most were not from pipelines.) Cost categories varied widely. Third party claims varied from less than 1% to more than 95% of total damages. Natural resource damages also varied from under 3% to 95%. Response costs also varied widely. The data set included 5 pipeline oil spills. The total known costs of the pipeline spills ranged from \$4.3 million to \$71.4 million.

The report concludes that, "[s]pills are costly events, and depending on the size and location of the spill may cost millions of dollars * * * The inability to account for all the costs of spills also has implications in other regulatory programs. Costs per unit spilled are often used in regulatory settings and the lack of complete data on the total costs of spills might result in inadequate liability limits."

OPS recognizes its data problems. To illustrate a few examples, the original estimate of the PEPCO spill the operator provided was \$50,000 + of property damage. On further prodding the operator responded with supplemental reports raising costs to over \$50 million. Note that OPS reporting of accidents lumps together the categories of product lost, property damage and response costs, and environmental damage. This makes any kind of analysis extremely difficult.

A closer examination of OPS spill reports confirmed the DOT Inspector General's audit conclusion that OPS data collection concerning costs of oil spills is poor. The cause of this problem is two-fold.

(1) The need to collect improved data by requiring operators to report their data by category, for example to separately indicate cost of product loss, property damage to the operator, private parties, and to the public in terms of

natural resource damages. A more detailed listing of the costs of restoration and clean-up is necessary for better analysis, and

(2) Presently, accident reporting regulations require that operators report accident cost no later than 30 days from the incident occurrence. Supplemental reports are required thereafter when new information is available. Because of the complexity of some major oil spills, cleanup and restoration costs may not be known for several years after the spill. In a 1997 accident that OPS recently reexamined, the final costs have not been decided because the case is still under litigation.

Pipeline operators, as well as OPS, have not been diligent in requesting and providing supplemental reports. OPS will soon be taking corrective actions to ensure that timely and accurate supplemental reports are provided. In the absence of appropriate data OPS recognizes that it cannot appropriately determine the benefits of regulations which reduce the number of oil spills. However, as the data from NOAA indicate as well as the recent information from the PEPSCO spill, even the reported costs from oil spills represent a significant social cost to society. OPS regrets its data problems. However, as NOAA reports, OPS is not alone among Federal regulatory agencies in collecting insufficient spill data. OPS has recently proposed changes to its gas accident reporting. It will be proposing changes to its oil spill accident reporting requirements in the future.

However, the importance of this regulation in preventing the consequences of releases from hazardous liquid pipelines that could affect high consequence areas requires that OPS place this requirement on the industry in the absence of complete spill data. As stated in this evaluation, OPS concludes that the rule is justified based on the modest costs to implement and the subjective benefits of improving knowledge of pipe condition, addressing public concerns, and reducing the frequency and consequence of pipeline releases that affect high consequence areas. OPS concludes that this is adequate justification.

5. *The definition of high consequence areas should be expanded to include all national parks and fish hatcheries.* The Department of the Interior and the Environmental Protection Agency strongly recommended that the National Parks and National Fish Hatcheries be included as high consequence areas. We have not included these areas in the definition of high consequence areas. We will consider additional protection

for these areas, among others, in a future rulemaking.

The following section summarizes the final regulatory evaluation's findings.

Hazardous liquid pipeline spills can adversely affect human health and the environment. The magnitude of this impact differs. There are some areas in which the impact of a spill will be more significant than it would be in others due to concentrations of people who could be affected or to the presence of environmental resources that are unusually sensitive to damage. Because of the potential for dire consequences of pipeline failures in certain areas, these areas merit a higher level of protection. OPS is promulgating this regulation to afford the necessary additional protection to these high consequence areas.

Numerous investigations by OPS and the National Transportation Safety Board (NTSB) have highlighted the importance of protecting the public and environmentally sensitive areas from pipeline failures. NTSB has made several recommendations to ensure the integrity of pipelines near populated and environmentally sensitive areas. These recommendations included requiring periodic testing and inspection to identify corrosion and other damage, establishing criteria to determine appropriate intervals for inspections and tests, determining hazards to public safety from electric resistance welded pipe and requiring installation of automatic or remotely-operated mainline valves on high-pressure lines to provide for rapid shutdown of failed pipelines.

Congress also directed OPS to undertake additional safety measures in areas that are densely populated or unusually sensitive to environmental damage. These statutory requirements included having OPS prescribe standards for identifying pipelines in high density population areas, unusually sensitive environmental areas, and commercially navigable waters; issue standards requiring periodic inspections using internal inspection devices on pipelines in densely-populated and environmentally sensitive areas; and survey and assess the effectiveness of emergency flow restricting devices, and prescribe regulations on circumstances where an operator must use the devices.

This rulemaking addresses the target problem described above, and is a comprehensive response to NTSB's recommendations and Congressional mandates, as well as pipeline safety and environmental issues raised over the years.

This rule focuses on a systematic approach to integrity management to reduce the potential for hazardous liquid pipeline failures that could affect populated and unusually sensitive environmental areas, and commercially navigable waterways. This rulemaking requires pipeline operators to develop and follow an integrity management program that continually assesses, through internal inspection, pressure testing, or equivalent alternative technology, the integrity of those pipeline segments that could affect areas we have defined as high consequence areas i.e., populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. The program must also evaluate the segments through comprehensive information analysis, remediate integrity problems and provide additional protection through preventive and mitigative measures.

This final rule (the first in a series of integrity management program regulations) covers hazardous liquid pipeline operators that own or operate 500 or more miles of pipeline used in transportation. OPS intends to propose integrity management program requirements for the liquid operators not covered by this final rule and for natural gas transmission operators. OPS chose to start the series with this group of hazardous liquid operators because the pipelines they operate have the greatest potential to adversely affect the environment, based on the volume of product these pipelines transport. Further, by focusing first on these liquid operators, OPS is addressing requirements for an estimated 86.7 percent of hazardous liquid pipelines. It is estimated that approximately 35.5 thousand miles (of the 157,000 miles of hazardous liquid pipeline in the U.S.) will be impacted by this final rule.

We have estimated the cost to develop the necessary program at approximately \$5.94 million, with an additional annual cost for program upkeep and reporting of \$660,000. An operator's program begins with a baseline assessment plan and a framework that addresses each required program element. The framework indicates how decisions will initially be made to implement each element. As decisions are made and operators evaluate the effectiveness of the program in protecting high consequence areas, the program will be continually updated and improved.

The rule requires a baseline assessment of covered pipeline segments through internal inspection, pressure test, or use of other technology capable of comparable performance. The baseline assessment must be completed

within seven years after the final rule becomes effective. After this baseline assessment, an operator is further required to periodically re-assess and evaluate the pipeline segment to ensure its integrity. It is estimated that the cost of periodic reassessment will generally not occur until the sixth year unless the baseline assessment indicates significant defects that would require earlier reassessment. Integrating information related to the pipeline's integrity is a key element of the integrity management program. Costs will be incurred in realigning existing data systems to permit integration and in analysis of the integrated data by knowledgeable pipeline safety professionals. The total costs for the information integration requirements in this rule are \$2.95 million in the first year and \$1.5 million annually thereafter.

The rule requires operators to identify additional preventive or mitigative measures that would enhance public safety or environmental protection based on a risk analysis of the pipeline segment. One of the many preventive or mitigative actions an operator may take is to install an EFRD on the pipeline segment. OPS could not estimate the total cost of installing EFRDs because OPS does not know how many operators will install them. Additionally, requirements have been added for an operator to evaluate its leak detection capability and modify that capability, if necessary. OPS does not know how many operators currently have leak detection systems or how many will be installed or upgraded as a result of this rule. OPS was therefore also unable to estimate the total costs of the leak detection requirements.

Affected operators will be required to assess more line pipe in segments that could affect high consequence areas as a result of this rule than they would have been expected to assess if the rule had not been issued. Integrity assessment consists of a baseline assessment, to be conducted over the first seven years after the effective date of the rule, and subsequent re-assessment at intervals not to exceed every five years.

OPS has estimated the annual cost of additional baseline assessment that will be required by this rule as \$9.95 million. The cost for additional re-assessment that will be required to meet the five-year re-assessment requirement is \$17 million per year. Cost impact will be greater in the sixth and seventh years after the effective date of the rule due to an overlap between baseline inspection and the initial subsequent testing. The

additional costs in these two years are estimated at \$38.2 million.

The benefits of this rule can not easily be quantified but can be described in qualitative terms. Issuance of this final rule ensures that all operators will perform at least to a baseline safety level and will contribute to an overall higher level of safety and environmental performance nationwide. It will lead to greater uniformity in how risk is evaluated and addressed and will provide more clarity in discussion by government, industry and the public about safety and environmental concerns and how they can be resolved.

Much of the final rule is written in performance-based language. A performance-based approach provides several advantages: encouraging development and use of new technologies; supporting operators' development of more formal, structured risk evaluation programs and OPS's evaluation of the programs; and providing greater ability for operators to customize their long-term maintenance programs.

The rule has also stimulated the pipeline industry to begin developing a supplemental consensus standard to support risk-based approaches to integrity management. The rule has further fostered development of industry-wide technical standards, such as repair criteria to use following an internal inspection.

Our emphasis on an integrity-based approach encourages a balanced program, addressing the range of prevention and mitigation needs and avoiding reliance on any single tool or overemphasis on any single cause of failure. This orientation will lead to addressing the most significant risks in populated areas, unusually sensitive environmental areas, and commercially navigable waterways. Commercially navigable waterways are included because of their importance as a supply route of vital resources to many American communities as well as their role in the national defense system. This integrity-based approach is the best opportunity to improve industry performance and assure that these high consequence areas get the protection they need. It also addresses the interrelationships among failure causes and benefits the coordination of risk control actions, beyond what a solely compliance-based approach would achieve.

The final rule provides for a verification process, which gives the regulator a better opportunity to influence the methods of assessment and the interpretation of results. OPS will provide a beneficial challenge to

the adequacy of an operator's decision process. Requiring operators to use the integrity management process, and having regulators validate the adequacy and implementation of this process, should expedite the operators' rates of remedial action, thereby strengthening the pipeline system and reducing the public's exposure to risk.

A particularly significant benefit is the quality of information that will be gathered as a result of this proposal to aid operators' decisions about providing additional protections. Two essential elements of the integrity management program are that an operator continually assess and evaluate the pipeline's integrity, and perform an analysis that integrates all available information about the pipeline's integrity. The process of planning, assessment and evaluation will provide operators with better data on which to judge a pipeline's condition and the location of potential problems that must be addressed.

Integrating this data with the environmental and safety concerns associated with high consequence areas will help prompt operators and the Federal and state governments to focus time and resources on potential risks and consequences that require greater scrutiny and the need for more intensive preventive and mitigation measures. If baseline and periodic assessment data is not evaluated in the proper context, it is of little or no value. It is imperative that the information an operator gathers is assessed in a systematic way as part of the operator's ongoing examination of all threats to the pipeline integrity. The rule is intended to accomplish that.

The public has expressed concern about the danger hazardous liquid pipelines pose to their neighborhoods. The integrity management process leads to greater accountability to the public for both the operator and the regulator. This accountability is enhanced through our choice of a map-based approach to defining the areas most in need of additional protection—the visual depiction of the populated areas, unusually sensitive environmental areas, and commercially navigable waterways in need of protection focuses on the safety and environmental issues in a manner that will be easily understandable to everyone. The system integrity requirements and the sharing of information about their implementation and effectiveness will assure the public that operators are continually inspecting and evaluating the threats to pipelines that pass through or close to populated areas to better ensure that the pipelines are safe.

OPS has not provided quantitative benefits for the continual integrity management evaluation required in this final rule. OPS does not believe, however, that requiring this comprehensive process, including the re-assessment of pipelines in high consequence areas at a minimum of once every five years, will be an undue burden on hazardous liquid operators covered by this proposal. OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated and important environmental areas and commercially navigable waterways, is benefit enough to promulgate these requirements.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), OPS 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 hazardous liquid operators that own or operate 500 or more miles of pipeline. Because of this limitation on pipeline mileage, only 66 hazardous liquid pipeline operators (large national energy companies) covering 86.7 percent of regulated liquid transmission lines are impacted by this final rule. Based on this, and the evidence discussed above, I certify that this final rule will not have a significant impact on a substantial number of small entities.

Paperwork Reduction Act

This rule contains information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), the Department of Transportation has submitted a copy of the Paperwork Reduction Act Analysis to the Office of Management and Budget for its review. The name of the information collection is "Pipeline Integrity Management in High Consequence Areas." The purpose of this information collection is designed to require operators of hazardous liquid pipelines to develop a program to provide direct integrity testing and evaluation of hazardous liquid pipelines in high consequence areas.

Several commenters (pipeline operators and trade associations), suggested that OPS underestimated the time and cost to develop the necessary program as well as the time and costs to revise the program. OPS concurs with these comments and has revised the costs burden hours as shown below.

Sixty-six hazardous liquid operators will be subject to this final rule. It is estimated that 59 of these operators will

have to develop integrity management programs taking approximately 2800 hours per program. (Ten percent of hazardous liquid operators are estimated to already have sufficient programs to comply with the rule.) Each of the 59 operators would also have to devote 1,000 in the first year to integrate this data into current management information systems.

Additionally, all 66 operators will be required to update their programs on a continual basis. This will take approximately 330 hours per program annually. An additional 500 hours per operator (for the 90% of operators who do not have a program or whose program does not comply with the rule) will be required to annually integrate the data into the operator's current management information systems.

Operators are required to either use hydrostatic testing or smart pigging as a method to assess their pipelines. However, operators can use another technology if it can demonstrate it provides an equivalent understanding of the condition of the line pipe as the other two assessment methods. Operators have to provide OPS 90-days notice (by mail or facsimile) before using the other technology. OPS believes that few operators will choose this option. If they do choose an alternate technology, notice preparation should take approximately one hour. Because OPS believes few if any operators will elect to use other technologies, the burden was considered minimal and therefore not calculated.

Additionally, operators could seek a variance in limited situations from the required five-year continual re-assessment interval if they can provide the necessary justification and supporting documentation. Notice would have to be provided to OPS when an operator seeks a variance. OPS believes that approximately 10% of operators may request a variance. This is approximately 7 operators. The advance notification can be in the form of letter or fax. OPS believes the burden of a letter or fax is minimal and therefore did not add it to the overall burden hours discussed above.

Organizations and individuals desiring to submit comments on the information collection should direct them to the Office of Information and Regulatory Affairs, OMB, Room 10235, New Executive Office Building, Washington, D.C. 20503; Attention Desk Officer for the Department of Transportation. Comments must be sent within 30 days of the publication of this final rule.

The Office of Management and Budget is specifically interested in the following issues concerning the information collection:

- Evaluating whether the collection is necessary for the proper performance of the functions of the Department, including whether the information would have a practical use;
- Evaluating the accuracy of the Department's estimate of the burden of the collection of information, including the validity of assumptions used;
- Enhancing the quality, usefulness and clarity of the information to be collected; and minimizing the burden of collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology; e.g., permitting electronic submission of responses.

According to the Paperwork Reduction Act of 1995, no persons are required to respond to a collection of information unless a valid OMB control number is displayed. The valid OMB control number for this information collection will be published in the **Federal Register** after it is approved by the OMB. For more details, see the Paperwork Reduction Analysis available for copying and review in the public docket.

Executive Order 13084

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13084 ("Consultation and Coordination with Indian Tribal Governments"). Because this final rule does not significantly or uniquely affect the communities of the Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

Executive Order 13132

This final rule has been 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.

Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10,

1999) do not apply. Nevertheless, in a November 18–19, 1999 public meeting, OPS invited National Association of Pipeline Safety Representatives (NAPSR), which includes State pipeline safety regulators, to participate in a general discussion on pipeline integrity. Again in January, and February 2000, OPS held conference calls with NAPSR, to receive their input before proposing an integrity management rule.

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

We have analyzed the final rule 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, and have determined that this action would not significantly affect the quality of the human environment. We updated the Environmental Assessment that supported the proposed rule (65 FR 21695) to reflect the provisions of the final rule.

The final Environmental Assessment determined that the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the final rule. The following discussion summarizes the analysis provided in the final Environmental Assessment.

Many operators covered by the final rule already have internal inspection and testing programs. These operators typically place a high priority on the pipeline's proximity to populated areas, recreation and conservation areas, and environmental resources when making decisions about where and when to inspect and test pipelines. As a result, pipelines that could affect some of the defined high consequence areas have

already been recently assessed, and a sizeable fraction of pipelines in the remaining locations would likely have been assessed in the next several years, without the provisions of the rule. The primary effect of the rule—accelerating integrity assessment of pipeline segments that could affect some high consequence areas—only shifts the improved integrity assurance forward for a few years for most high consequence areas. Because pipeline failure rates are low, shifting the time at which these segments are assessed forward by a few years, has only a small effect on the likelihood of pipeline failures in or near high consequence areas.

Neither internal inspection nor pressure testing protect against all threats to pipeline integrity. Specifically, they do not prevent outside force damage, the most significant contributor to hazardous liquid pipeline failures. However, the rule does require operators to conduct an integrated analysis and evaluation of all the potential threats to pipeline integrity, and to consider additional preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause—like third party damage—these evaluations should result in additional risk controls to address these threats. However, without knowing the specific high consequence area locations, the specific risks present at these locations, and the existing operator risk controls (including those that surpass the current minimum regulatory requirements), it is difficult to determine the impact of this requirement.

A number of liquid operators covered by the rule already perform integrity evaluations or formal risk assessments that consider the impacts of pipeline system failures on the environment and population in proximity to their lines. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. Thus, it is expected that additional risk controls resulting from the integrated evaluation will be limited with most new actions customized to address site-specific integrity issues that the operator may not have previously recognized. For many high consequence areas, it is probable that operators will determine the existing preventive and mitigative activities provide adequate protection, and that the small risk reduction benefits of additional risk controls are not justified.

The primary benefits of the final rule will be to establish requirements for conducting integrity assessments and periodic evaluations of the pipeline

segments that could affect high consequence areas. In effect, this will establish uniform integrity management programs across the pipeline industry and enhance the integrity assessment activities many operators are currently implementing. It will also require operators who have minimal, or no, integrity assessment and evaluation programs to raise their level of performance. Thus, the rule is expected to ensure a more consistent, and overall higher level of integrity assurance for high consequence areas across the industry.

In accordance with 40 CFR Section 1508.13, based on the updated Environmental Assessment, and no receipt of comment or information showing otherwise, we have prepared a Finding of No Significant Impact (FONSI) for this final rule. The updated Environmental Assessment and the Finding of No Significant Impact are available for review in the docket.

List of Subjects in 49 CFR Part 195

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

In consideration of the foregoing, OPS 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

2. New §§ 195.450 and 195.452 are added under new undesignated centerheadings of “High Consequence Areas” and “Pipeline Integrity Management”, respectively, to subpart F to read as follows:

High Consequence Areas

195.450 Definitions.

Pipeline Integrity Management

195.452 Pipeline integrity management in high consequence areas.

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

(b) *What must an operator do?* (1) No later than March 31, 2002, an operator must develop a written integrity management program that addresses the risks on each pipeline segment that could affect a high consequence area. An operator must include in the program:

(i) An identification of all pipeline segments that could affect a high consequence area. A pipeline segment in a high consequence area is presumed to affect that area unless the operator's risk assessment effectively demonstrates otherwise. (See Appendix C of this part for guidance on identifying pipeline segments.) An operator must complete this identification no later than December 31, 2001;

(ii) A plan for baseline assessment of the line pipe (see paragraph (c) of this section);

(iii) A framework addressing each element of the integrity management program, including continual integrity assessment and evaluation (see

paragraphs (f) and (j) of this section). The framework must initially indicate how decisions will be made to implement each element.

(2) An operator must implement and follow the program it develops.

(3) In carrying out this section, an operator must follow recognized industry practices unless the section specifies otherwise or 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. For low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies. An operator must assess the integrity of the line pipe by:

(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 specified in § 195.58 or to the facsimile number specified in § 195.56;

(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 the baseline assessment be completed?* (1) *Time period.* An operator must establish a baseline assessment schedule to determine the priority for assessing the pipeline segments. An operator must complete the baseline assessment by March 31, 2008. An operator must assess at least 50% of the line pipe subject to the requirements of this section, beginning with the highest risk pipe, by September 30, 2004.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section, an operator may use an integrity assessment conducted after January 1, 1996, if the integrity assessment method meets the requirements of this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must re-assess the line pipe according to the requirements of paragraph (j)(3) of this section.

(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 repair 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 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 be taken to address integrity issues?* (1) *General requirements.* An operator must take prompt action to address all pipeline integrity issues raised by the assessment and information analysis. An operator must evaluate all anomalies and repair those anomalies that could reduce a pipeline's integrity. An operator must comply with § 195.422 in making a repair.

(2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine the need for repair. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or when an operator receives the final internal inspection report. The date of discovery can be no later than the date of the integrity assessment results or the final report.

(3) *Review of integrity assessment.* An operator must include in its schedule for evaluation and repair (as required by paragraph (h)(4) of this section), a schedule for promptly reviewing and analyzing the integrity assessment results. After March 31, 2004, an operator's schedule must provide for review of the integrity assessment results within 120 days of conducting each assessment. The operator must obtain and assess a final report within an additional 90 days.

(4) *Schedule for repairs.* An operator must complete repairs according to a schedule that prioritizes the conditions for evaluation and repair. An operator must base the schedule on the risk factors listed in paragraph (e)(1) of this section and any pipeline-specific risk factors the operator develops. If an operator cannot meet the schedule for any of the conditions addressed in paragraphs (h)(5)(i) through (iv) of this section, the operator must justify the reasons why the schedule cannot be met 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 until a permanent repair is made. An operator must send a notice to the address specified in

§ 195.58 or to the facsimile number specified in § 195.56.

(5) *Special requirements for scheduling repairs—(i) Immediate repair conditions.* An operator's evaluation and repair schedule must provide for immediate repair conditions. To maintain safety, an operator will need to temporarily reduce operating pressure or shut down the pipeline until the operator can complete the repair of these conditions. An operator must base the temporary operating pressure reduction on remaining wall thickness. An operator must treat the following conditions as immediate repair conditions:

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

(B) Predicted burst pressure less than the maximum operating pressure at the location of the anomaly. Burst pressure has been calculated from the remaining strength of the pipe, using a suitable metal loss strength calculation, e.g., 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 available at the addresses listed at § 195.3.

(C) Dents on the top of the pipeline (above 4 and 8 o'clock position) with any indicated metal loss.

(D) Significant anomaly that in the judgment of the person evaluating the assessment results requires immediate action.

(ii) *60-day conditions.* Except for conditions listed in paragraph (h)(5)(i) of this section, an operator must schedule for evaluation and repair all dents, regardless of size, located on the top of the pipeline (above 4 and 8 o'clock position) within 60 days of discovery of the condition.

(iii) *Six-month conditions.* Except for conditions listed in paragraph (h)(5)(i) or (ii) of this section, an operator must schedule evaluation and repair of the following within six months of discovery of the condition:

(A) Dents with metal loss or dents that affect pipe curvature at a girth or seam weld.

(B) Dents with reported depths greater than 6% of the pipe diameter.

(C) Remaining strength of the pipe results in a safe operating pressure that is less than the current established MOP at the location of the anomaly using a suitable safe operating pressure calculation method (e.g., 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 available at the addresses listed at § 195.3.

(D) Areas of general corrosion with a predicted metal loss of >50% of nominal wall.

(E) Predicted metal loss of >50% of nominal wall at crossings of another pipeline.

(F) Weld anomalies with a predicted metal loss >50% of nominal wall.

(G) Potential crack indications that when excavated are determined to be cracks.

(H) Corrosion of or along seam welds.

(I) Gouges or grooves greater than 12.5% of nominal wall.

(iv) *Other conditions.* An operator must schedule evaluation and repair of the following conditions:

(A) Data that reflect a change since last assessed.

(B) Data that indicate mechanical damage that is located on the top half of the pipe.

(C) Data that indicate anomalies abrupt in nature.

(D) Data that indicate anomalies longitudinal in orientation.

(E) Data that indicate anomalies over a large area.

(F) Anomalies located in or near casings, crossings of another pipeline, and areas with suspect cathodic protection.

(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 past and present integrity assessment results, information analysis (paragraph (g) of this section), and decisions about repair, 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 is obtainable under paragraph (j)(2) of this section. An operator must notify OPS nine months before the end of the intervals of five years or less of the reason why the operator intends to justify a longer interval. An operator must send a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56. The notice must state a proposed alternative interval.

(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 intervals of five years or less that the operator may require a longer assessment interval. An operator must

send a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56. The Operator may have up to an additional 180 days to complete the assessment.

(5) *Assessment methods.* An operator must assess the integrity of the line pipe by:

(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 60 days before conducting the assessment, by sending a notice to the address specified in § 195.58 or to the facsimile number specified in § 195.56.

(6) However, for low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(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?* 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.

3. A new Appendix C is added to part 195 to read as follows:

Appendix C to Part 195—Guidance for Implementation of 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 can 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.

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 condition of pipeline (pressure, flow rate, etc.) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(8) The hydraulic gradient of pipeline.

(9) The diameter of 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 years
Low	< 25 years

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).
Medium	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils).
Low	Flammable—flashpoint <100F	(Gasoline, JP4, low flashpoint crude oils).
	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 measures 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 ____-% (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 repairing anomalies, criteria for repair actions and actions taken to evaluate and repair the anomalies;

(17) other remedial actions planned or taken;

(18) schedule for reviewing and analyzing integrity assessment results;

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

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

(21) criteria for determining EFRD installation;

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

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

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Administrator.

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