US Department of Transportation
Pipelines and Hazardous Materials Safety Administration
Pipeline Safety

Integrity Management Program
49 CFR 195.452

Integrity Management
Inspection Protocols

December 2007

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Explanation of Inspection Form Format

The next two pages provide a brief description of each item in the Integrity Management Inspection Form.

Protocol #	*Keywords reflecting the subject area of the Protocol Question are entered here. Each question has a unique number, as indicated to the left.*
Protocol Question	*Question to be answered in reviewing an operator's Integrity Management Program or the implementation of its Program.* *Questions in the Integrity Management Inspection Protocols generally cover two main aspects of an operator's Program: One part deals with the inspection of a particular aspect or feature of the operator's Integrity Management processes, procedures, technical methods, etc. The second part addresses how effectively the operator has implemented that process and the results that have been obtained.*
This section contains additional guidance and items for consideration by the inspector in reviewing operator response to the protocol question. This guidance presents characteristics typically expected in an effective Integrity Management Program consistent with the intent of the Rule. Some, all, or none of these characteristics may be appropriate depending on factors unique to each protocol, and the operator's Integrity Management Program and its pipeline assets. Operators should be able to demonstrate that their programs address each of these characteristics or should be able to describe how their program will be effective in their absence. *For some protocol questions, this portion of the inspection form is also used to articulate specific prescriptive requirements in the Rule. These requirements are mandatory for all Integrity Management Programs.*	
Rule Requirement	*Reference to related rule requirement(s)*
Inspection Issues Summary	*This space is provided to record any issues or concerns the inspector identifies in reviewing the operator's response to the protocol question.*

Inspection Results *The boxes to the right are checked based on the information supplied in the Summary.*		**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed: *Documents reviewed in answering the Protocol Question are listed below.*

Document Number	Rev.	Date	Document Title

Inspection Notes:

This section is provided to record more detailed information about the operator's program obtained during the review of the operator's response to the protocol question. For protocol questions dealing with the implementation of a particular facet of an operator program, a summary of the records review is entered at this location.

Integrity Management

Inspection Form

Name of Operator:

Headquarters Address:

Company Official:
Phone Number:
Fax Number:
Operator ID:
Activity ID:

Persons Interviewed	Title	Phone No.	E-Mail
Primary Contact:			

PHMSA/State Representatives: **Dates:**

System Description:

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Integrity Management
Inspection Protocol 1

Identification of Pipeline Segments That Could Affect High Consequence Areas

Scope:

This Protocol addresses the identification of pipeline segments that could affect one or more HCAs. This Protocol addresses all of the steps to perform the segment identification, including identification of HCAs, correlation of HCAs to pipeline locations, commodity transport to HCAs from spills located outside of HCA boundaries, buffer zones, and justification for excluding segments physically located within a HCA. This Protocol does not address how the segment identification results are further used in other Integrity Management (IM) Program elements.

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Protocol # 1.01	Segment Identification: HCA Identification
Protocol Question	Does the process to identify segments that could affect HCAs include steps to identify, document, and maintain up-to-date geographic locations and boundaries of HCAs using the NPMS and other information sources as necessary? ——————————— Verify that the operator correctly identifies and maintains up-to-date locations and boundaries of HCAs using NPMS and other information sources as appropriate for all states/regions in which it operates.

An operator's process to identify pipeline segments that could affect HCAs must identify the location of HCAs that could be affected by pipeline failures. To accomplish this step, the operator's documented IM process would be expected to include the following elements:

1. The use of NPMS (or equivalent sources) to identify HCAs.
2. Adequate measures to identify ecological USAs in Pennsylvania, if applicable.
3. Adequate provisions to assure that local knowledge, information obtained from routine field activities (e.g., ROW surveillance, aerial surveys), and other information sources are used as required to supplement NPMS data in order to accurately reflect current conditions in the vicinity of the pipeline.
4. Provisions for periodic review and update of HCA boundaries, including timely use of revised NPMS data and local information in the update (e.g., per the requirements of §195.452 (d)(3)).

Rule Requirement	§195.452 (f) 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.
	§195.450 Definitions. A 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.
	§195.6 Unusually Sensitive Areas (USAs). As used in this part, a USA means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release…

1.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.01 Inspection Issues Summary

1.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

1.01 Inspection Notes

Protocol # 1.02	Segment Identification: Direct Intersect Method and Direct Intersect Exceptions
Protocol Question	Does the operator have an adequate process to determine all locations where its pipeline system is located in an HCA? If applicable, has the operator developed and documented an adequate and convincing technical justification for concluding that any segments located in an HCA could not affect the HCA in the event of a release? Verify that the operator determined all locations where its pipeline system is located in an HCA (i.e., determine if the operator correlated its complete pipeline system(s) maps with the HCA maps, and identified areas where the pipeline system intersects an HCA). Determine if the operator has taken exception to any segments that directly intersect an HCA. If so, verify that the operator has provided an adequate and convincing technical justification for that conclusion.

The purpose of this question is to review the operator's identification of intersections between the operator's pipeline and HCAs and the operator's technical justification for excluding any segments that directly intersect an HCA. An effective operator process for identification of these intersections would be expected to have the following characteristics:

1. The process requires that segments that are physically located within HCAs are identified and defined by specific locations that represent the place where the pipeline actually intersects that HCA boundary. (The entire segment that could affect the HCA could be much larger based on transport analysis.)
2. The process requires that pipeline facilities that are located in HCAs are identified (not just line pipe).
3. Any GIS or other mapping software used by operators employs a valid analysis algorithm or methodology to identify segments that intersect HCAs.
4. Any manual analysis techniques used by operators employ a valid analysis technique or methodology to identify segments that intersect HCAs.

§195.452 (a) presumes that a pipeline segment within a HCA could affect that HCA. If the operator concludes that some segments within HCAs could not affect the HCAs, then a technical justification for this conclusion is required. If the operator intends to maintain any segment intersecting a HCA could not affect that HCA, then an effective operator process would be expected to include provisions for such a technical justification with the following characteristics:

1. Guidance for performing an analysis to substantiate the conclusion that a pipeline segment located within an HCA could not affect the HCA.
2. An adequate level of rigor specified for any analysis that is used to justify the conclusion that a segment located in an HCA could not affect the HCA.
3. A valid analysis to justify the conclusion that a pipeline segment located within an HCA could not affect the HCA. The operator's analysis should consider the following factors:
   - HVL properties.
   - Topographical considerations.
   - HCA properties.

Rule Requirement	§195.452 (f) 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.
	§452 (a) *What pipelines are covered by this section?* The section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

1.02 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.02 Inspection Issues Summary

1.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

1.02 Inspection Notes

Protocol # 1.03	Segment Identification: Release Locations and Spill Volumes
Protocol Question	Does the operator's segment identification analysis process include a technically adequate method to determine the locations/scenarios and volume of potential commodity releases? ——————————— Verify that the operator's identified release locations and spill volumes are appropriate, technically adequate, and determined consistent with its documented process.

The operator's approach for analyzing the potential effects of pipeline failures that could affect HCAs must define potential locations on the pipeline where releases could occur. An effective operator program would be expected to consider the following elements:

1. Proximity to water crossings;
2. Variations in topography near the line;
3. Variations in distance between the pipeline and the HCA (for HCAs that do not intersect the pipeline);
4. Adequate choice of release locations, if fixed spacing along the pipeline is used in the definition of locations;
5. Consideration of spills involving pipeline facilities (e.g., breakout tanks).

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the volume of commodity that could be released in the event of a failure. An effective operator program would be expected to include appropriate treatment of the following factors that affect estimation of spill volume:

1. Failure hole size (see note);
2. Operating conditions (e.g., flow rate, operating pressure);
3. Leak detection and response time;
4. Calculations of drain down following leak or rupture;
5. Release rate estimates, if air dispersion of vapor clouds is a transport mechanism that is applicable to the operator's system; and
6. Pipeline system design factors (e.g., pipe diameter, distance between isolation valves, location of tanks and other facilities).

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to include appropriate treatment of the above factors.

Note: Because an adequate spill volume analysis may require consideration of various scenarios and combinations of assumptions regarding different variables, the operator's release estimate analysis would be expected to include a sensitivity analysis to variations in assumptions, including consideration of both catastrophic failure and leaks below detection limits.

Rule Requirement	§452 (f) 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.

1.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.03 Inspection Issues Summary

1.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

1.03 Inspection Notes

Protocol # 1.04	Segment Identification: Overland Spread of Liquid Pool
Protocol Question	Does the operator's process include an adequate analysis of overland flow of liquids to determine the extent of commodity spread and its effects on HCAs? Verify that the operator produced an overland spread analysis (if applicable) that is technically adequate and consistent with its program requirements.

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the distance and direction of the commodity spilled from a potential failure at a location on the pipeline and determining if the identified direction and extent of the spill could result in adverse consequences to a HCA. Commodity spilled from hazardous liquid pipelines may spread by land, water, or air to impact HCAs. This protocol considers the operator's analysis of overland spill transport. An effective operator process would be expected to include the following characteristics in analyzing overland spread of spills:

1. The assumptions used in the overland spread analysis are valid for all applications of the assumption (e.g., assumptions used to conduct overland spread analysis used as a basis for buffer zone size should be valid for all systems and locations to which the buffer zone is applied).
2. The overland spread analysis technique adequately and accurately evaluates the effects of topography on overland spread consequences.
3. Assumptions on operator spill response actions used to determine the pool spread limits are valid.
4. The overland spread analysis process identifies and adequately analyzes local factors such as ditches, sewers, farm tile, drains, etc.
5. Any computer modeling of overland transport mechanisms that is used produces valid overland spread consequence results.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the overland spread distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) 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.

1.04 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.04 Inspection Issues Summary

1.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

1.04 Inspection Notes

Protocol # 1.05	Segment Identification: Water Transport Analysis
Protocol Question	Does the operator's process include a technically adequate analysis of water transport of liquids to determine the extent of commodity spread and its effects on HCAs? ———————————— Verify that the operator produced a water transport analysis (if applicable) that is technically adequate and consistent with its program requirements.

This protocol considers the operator's analysis of spill transport through waterways. An effective operator process would be expected to include the following characteristics in analyzing the transport of spills by water:

1. The analysis adequately evaluates the effects of all applicable factors, including stream conditions, flow characteristics, and water properties on water transport consequences.
2. The assumptions used in the analysis are valid for all systems and locations to which the assumptions are applied (e.g., assumptions used to conduct water transport analysis as a basis for buffer zone size are valid for all systems and locations to which the buffer zone is applied).
3. Pool spread limits based on assumptions of operator spill response actions are defensible.

Additional factors that may be important to understanding water transport of spilled commodity include:

1. Changes in commodity properties due to interaction with the environment (such as dissolved MTBE transport and change in buoyancy and density due to evaporation).
2. Commodity solubility.
3. Abnormal stream conditions such as flood or storm conditions, etc.
4. Subsurface water transport as well as surface water transport.
5. Indirect introduction into water due to overland pool spread that reaches waterways.
6. Introduction into water from spray releases.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the spill water transport distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) 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.

1.05 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.05 Inspection Issues Summary

1.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

1.05 Inspection Notes

Protocol # 1.06	Segment Identification: Air Dispersion Analysis
Protocol Question	Does the operator's documented consequence analysis process include a technically adequate analysis of the air dispersion of vapors from the release of highly volatile liquids and volatile liquids to determine the extent of harmful commodity vapor spread and its effects on HCAs? ——————————— Verify that the operator produced an analysis of the air dispersion of vapors (if applicable) that is technically adequate and consistent with its program requirements.

This protocol considers the operator's analysis of spill transport through air dispersion. An effective operator process would be expected to have the following characteristics in analyzing the dispersion of spills through air:

1. The process includes air dispersion analysis where appropriate for the operator's system and release scenarios.
2. The operator's selection of analysis model and software tool is appropriate for the operator's system and release scenario.
3. The analysis correctly models the physical properties of the commodity that could be released.
4. The air dispersion analysis inputs and assumptions used to determine if the release could affect a HCA are adequate.
5. If the air dispersion analysis involves consideration of threshold levels of concern for the adverse effects of releases, then the thresholds that are used are based on valid criteria to determine if releases could affect a HCA.
6. For completeness, the air dispersion analysis considers the potential for any additional significant release effects (e.g., chemical byproducts of combustion) to adversely affect a HCA.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the vapor dispersion distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) 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.

1.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.06 Inspection Issues Summary

1.06 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

1.06 Inspection Notes

Protocol # 1.07	Segment Identification: Identification of Segments that Could Indirectly Affect an HCA
Protocol Question	Does the operator's analysis process adequately identify all locations of segments that do not intersect, but could indirectly affect, an HCA? ———————————— Review the operator's analysis and determine if there is reasonable assurance that the operator has correctly identified the endpoints of segments that could affect an HCA.

This protocol addresses the results of the operator's process for segments that do not intersect, but could affect, HCAs. An effective operator process would be expected to have the following characteristics:

1. The process requires that segments that could affect HCAs (according to the analysis reviewed under protocols 1.04 through 1.06) are identified and defined by specific beginning and ending endpoints.
2. If the operator used a buffer zone approach to identify segments that could affect HCAs, an approach that is reasonable, technically justified, and identifies the endpoints of segments that could affect an HCA.
3. If any segments intersect a buffer zone, but were declared to not affect the HCA, a documented and adequate technical justification for this assertion.
4. Identification of pipeline facilities that could affect HCAs.

Rule Requirement	§452 (f) 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.

1.07 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.07 Inspection Issues Summary

1.07 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

1.07 Inspection Notes

Protocol # 1.08	Segment Identification: Timely Completion of Segment Identification
Protocol Question	Did the operator complete segment identification by the dates prescribed in 452(b)(2)?

The operator must identify all segments that could affect HCAs by the prescribed dates:

1. 12/31/2001 for Category 1 pipelines
2. 11/18/2002 for Category 2 pipelines
3. Beginning of operation for Category 3 pipelines

Rule Requirement	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — December 31, 2001 Category 2 — November 18, 2002. Category 3 — Date the pipeline begins operation.

1.08 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

1.08 Inspection Issues Summary

1.08 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

1.08 Inspection Notes

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Integrity Management Inspection Protocol 2

Baseline Assessment Plan

Scope:

This Protocol addresses the development of the Baseline Assessment Plan. This Plan identifies the integrity assessment method(s) for each pipeline segment that can affect a High Consequence Area, and provides the schedule when these assessments will be performed. This Protocol addresses the selection of assessment methods and the development of an integrated, risk-based prioritized assessment schedule.

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Protocol # 2.01	**Baseline Assessment Plan: Assessment Methods**
Protocol Question	Are the assessment methods shown in the Baseline Assessment Plan appropriate for the pipeline specific conditions and risk factors identified for each segment?

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process must exhibit the following characteristics:

1. The assessment methods selected for each segment are effective and appropriate for identifying anomalies associated with the specific risk factors identified for the segment. Specific risk factors can include fatigue cracks, stress corrosion cracking (SCC), internal corrosion, general external corrosion, corrosion along seam or girth welds, construction defects such as wrinkle bends, dents, etc. The operator should utilize industry information when evaluating previously unidentified risk factors.
2. If ILI tools are used, they are used in combinations that assure the capability to detect corrosion anomalies and deformation anomalies including dents, gouges and grooves.
3. All of the assessment methods and tools documented in the Baseline Assessment Plan comply with the acceptable methods specified in 195.452 (c) (1).
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. Indication/documentation that, if other technology is planned for use, the operator submitted a 90-day notification to PHMSA regarding the use of other technologies.

[For review of external corrosion direct assessment (ECDA) refer to protocols 7.03 and 7.05-7.08.]

Rule Requirement	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.
	§195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan: (i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. (A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves; (B) Pressure test conducted in accordance with subpart E of this part; (C) External corrosion direct assessment in accordance with §195.588; or (D)Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section ... (iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

2.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

2.01 Inspection Issues Summary

2.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

2.01 Inspection Notes

Protocol # 2.02	**Baseline Assessment Plan: Prioritized Assessment Schedule**
Protocol Question	Does the Baseline Assessment Plan include a prioritized schedule in accordance with §195.452 (d) that is based on the risk factors required by §195.452 (e)?

The rule requires that the operator develop a prioritized schedule for assessment of pipeline segments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Identification that all pipeline segments that could affect HCAs are included in the Baseline Assessment Plan. (If the plan identifies line pipe by piggable/testable sections, the documentation should identify a cross reference or other means by which the applicable segments that could affect HCAs can be identified.)
2. Incorporation of newly identified segments that could affect HCAs into the Baseline Assessment Plan within one year from the date the segment is identified as required by §195.452 (d) (3).
3. A prioritization process that considers risk factors that reflect the risk conditions for each pipeline segment, including, at a minimum, consideration of the risk factors contained in §195.452 (e).
4. Revision as appropriate to reflect the insights gained from completed assessments as well as other information that might impact the priority or assessment method of future integrity assessments.

An effective baseline assessment schedule should exhibit the following additional characteristics:

1. The schedule appears to be reasonable and achievable.
2. If the Baseline Assessment Plan prioritizes piggable or assessment sections of pipes where the assessment sections include multiple segments that can affect HCAs, the process for determining the relative priority of assessment sections is carefully explained. Furthermore, the methodology assures the highest risk segments that can affect HCAs are scheduled for assessment early in the period allotted for completing baseline assessments.

Inspection of Baseline Assessment Plan implementation should include a check of the following characteristics:

1. Assessments scheduled for completion were, in fact, completed.
2. Beginning with the highest risk pipe, at least 50% of the line pipe that can affect HCAs are scheduled to be assessed prior to the segments compliance deadline (September 30, 2004 for Category 1 and August 16, 2005 for Category 2). All baseline assessments of the line pipe that can affect HCAs are scheduled to be completed prior to the compliance deadline (March 31, 2008 for Category 1 pipe, February 17, 2009 for Category 2 pipe). Category 3 pipe must have a completed assessment prior to beginning operation.
3. Assessment methods were used as described in the plan.
4. The date on which assessment field activities are completed is recorded.
5. The total pipeline mileage for which assessments have been completed, and the total mileage that can affect HCAs for which assessments have been completed should be available.
6. Based on assessment results information reviewed during the inspection, the data in Part K (Mileage of Baseline Assessments Completed) of the most recent Form PHMSA F 7000-1.1 appear valid and completed per Instructions for Completing Form PHMSA F 7000-1.1.

Rule Requirement	§195.452 (f) *What are the elements of an integrity management program?* (2) A baseline assessment plan meeting the requirements of paragraph (c) of this section
	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

	§195.452 (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 ... (ii) A schedule for completing the integrity assessment;
	§195.452 (d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows: (1) *Time periods*. Complete assessments before the following deadlines:

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

	§195.452(d)(3) Newly-identified areas. 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 Sec. 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.
	§195.452(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. An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment.

2.02 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

2.02 Additional Data *(Type an **X** in the applicable box to verify task completion.)*	
	Annual Report Part K Data of the Most Recent Form PHMSA F 7000.1-1 Reviewed

2.02 Inspection Issues Summary

2.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

2.02 Inspection Notes

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Protocol # 2.03	Baseline Assessment Plan: Prior Assessments
Protocol Question	Does the Baseline Assessment Plan make use of prior assessments as baseline assessments?

Assessments performed prior to the effective date of the rule may be used as baseline assessments provided they are consistent with rule requirements for baseline assessments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Evidence that baseline assessments performed after January 1, 1996 but before March 31, 2002, for Category 1 pipelines have been performed using the methods prescribed in §195.452 (c) (1) and that repairs have been categorized and completed in accordance with the requirements of the IM rule if the line has been in service after March 31, 2002.
2. Evidence that baseline assessments performed after February 15, 1997 but before February 18, 2003, for Category 2 pipelines have been performed using the methods prescribed in §195.452 (c) (1) and that repairs have been categorized and completed in accordance with the requirements of the IM rule if the line has been in service after February 18, 2003.

Rule Requirement	§195.452 (d) (2) *Prior assessment*. To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows: <u>Pipeline</u> <u>Date</u> Category 1 January 1, 1996 Category 2 February 15,1997

2.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

2.03 Inspection Issues Summary

2.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

2.03 Inspection Notes

Integrity Management
Inspection Protocol 3

Integrity Assessment Results Review

Scope:

This Protocol addresses the review, validation, and evaluation of results from integrity assessments (i.e., in-line inspection, pressure testing, or other technologies). In addressing this program element, this protocol covers verification of information accuracy, the integration of other information about the pipeline with the assessment results to help identify and characterize defects, and obtain an improved understanding about the condition of the pipe.

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Protocol # 3.01	**Integrity Assessment Results Review: Qualifications of Individuals that Review and Evaluate Assessment Results**
Protocol Question	Does the operator have a formal, documented process to ensure that individuals who review and evaluate integrity assessment results are qualified to perform this work? ______________________ Review records such as job descriptions, resumes, training records, etc., to verify that individuals that review assessment results are qualified to do so.

The rule requires that individuals who review assessment results and information analysis be qualified to do so. An effective operator program would be expected to require that appropriate means be taken to ensure the requisite level of qualification, and contain the following characteristics:

1. Job description, task analysis, or other means to identify the qualification requirements for performing reviews of assessment results and information analysis, that address education, experience, skills, and training requirements, as appropriate.
2. Documentation of existing personnel skills, education, training, and experience that (1) demonstrates the individual's qualification and proficiency, and (2) identifies additional qualification needs for those individuals that do not meet all qualification requirements.
3. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.

[For review of individual qualifications for external corrosion direct assessment (ECDA) refer to protocol 7.03.]

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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).

3.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.01 Inspection Issues Summary

3.01 Documents Reviewed			*(Tab from bottom-right cell to add additional rows.)*
Document Number	**Rev.**	**Date**	**Document Title**

3.01 Inspection Notes

Protocol # 3.02	**Integrity Assessment Results Review: ILI Vendor Specifications**
Protocol Question	Do the requirements established by the operator for the In-Line Inspection (ILI) assessment process (such as ILI technical specifications, scope of work statements, etc.) assure that those responsible for conducting in-line integrity assessments (i.e., ILI tool vendors) understand their responsibilities in performing integrity assessments that comply with this rule?

ILI tool vendors perform an important role in pipeline integrity. However, the operator is ultimately responsible for the quality of assessments and the validity of tool data analysis. An effective operator program would be expected to demonstrate that the ILI vendor has met all of the requirements of the rule. This includes:

1. The final vendor report is provided within 180 days of completion of the assessment.
2. The vendor uses the tool(s) specified by the operator.
3. The vendor reports immediate conditions or other conditions indicating a serious threat to line integrity in a timely fashion.
4. The vendor report identifies and categorizes all anomalies.

[For review of vendor specifications for external corrosion direct assessment (ECDA) refer to protocol 7.03.]

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);
	§452 (h) *What actions must an operator take to address integrity issues?* (2) *Discovery of a condition*. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

3.02 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.02 Inspection Issues Summary

3.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.02 Inspection Notes

Protocol # 3.03	Integrity Assessment Results Review: Validation of Assessment Results
Protocol Question	Does the operator's integrity assessment results review process provide sufficient assurance that all activities required to verify the accuracy of the in-line inspection data are identified and implemented? ______________________ Review selected dig records to verify that physical pipeline data obtained from field excavations was appropriately used to validate ILI results.

After ILI tool runs are completed, an operator may implement a process by which called anomalies are excavated so that tool results may be validated using actual, measured defect characteristics, in order to have confidence in the assessment results. An effective operator program would be expected to have the following characteristics:

1. Determination of the appropriate number (representative sample) and type of defects (representative of the different types of anomalies called such as internal corrosion, external corrosion, and dents) for which validation digs are required.
2. Identification, collection, and documentation of all pertinent information during the validation dig process, and dissemination to the individuals reviewing assessment results.
3. Field validation digs that assure that the locations of all anomalies are verified, and that collect all information needed to compare the actual anomaly characteristics to the vendor report.

If an operator chooses not to validate tool results, an effective operator program would be expected to have documented justification to demonstrate that validation activities are not necessary for its circumstances.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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)
	§452 (h) (2) *Discovery of a condition*. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

3.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.03 Inspection Issues Summary

3.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.03 Inspection Notes

Protocol # 3.04	Integrity Assessment Results Review: Integration of Other Information with Assessment Results
Protocol Question	Does the operator's integrity management process documentation require the integration of additional sources of pertinent risk-factor data with the assessment results (either ILI, pressure testing, or "other technology") to support evaluation of the condition of the pipeline, or to make decisions related to the repair or remediation of pipeline defects? ______________________ Review records documenting the operator's review of assessment results to determine if the operator integrates and analyzes all appropriate sources of other information with the assessment data.

The rule requires that operators integrate assessment results with other pertinent information about the risk-conditions of the pipeline to uncover integrity issues that might not be evident from the assessment data alone. An effective operator program would be expected to have the following characteristics:

1. A process to ensure that the analyst is aware of and uses other sources of data in order to make the best integrity decisions (e.g., corrosion control data such as rectifier readings, close interval surveys, or corrosion coupon results).
2. A documented process by which data is collected and disseminated to persons evaluating assessment results.
3. A process that integrates the following types of information, as appropriate:
    - Previous assessment results;
    - Surveillance, testing, and other monitoring data (e.g., internal corrosion coupon monitoring);
    - Historical maintenance and repair information;
    - Uncertainty of assessment results including tool tolerances;
    - Any other information related to pipeline integrity; and
    - Information about how a failure would affect the high consequence area.
4. Consideration of new information such as industry reports on new technology, incident reports, etc.
5. Documentation of the overall results of integrated data analysis and conclusions regarding the integrity of the segment, including the nature of the integrity threats identified, and a reliable characterization of anomalies such as type of anomaly (e.g., internal corrosion, external corrosion, and dents), size (amount of metal loss, depth of dent) and location (e.g., axial location and circumferential orientation).
6. Identification and documentation of integrity issues and potential trends in the integrity of the pipeline.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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)
	452(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.

3.04 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.04 Inspection Issues Summary

3.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.04 Inspection Notes

Protocol # 3.05	Integrity Assessment Results Review: Identifying and Categorizing Defects
Protocol Question	Does the operator's process documentation provide adequate guidance to assure the appropriate categorization (and scheduling for repair) of all identified anomalies in accordance with the criteria contained in the rule? ______________________ Review assessment records to verify that defects have been discovered within 180 days of completion of the assessment and that defects have been categorized in accordance with the special requirements for scheduling remediation contained in §452 (h) (4).

Upon discovery of a condition, the operator is required to determine if the condition meets any of the rule's special requirements for scheduling remediation. If so, repair or remediation must be scheduled for completion within the time frames established by the rule. An effective operator program would be expected to have the following characteristics:

1. Provisions to ensure that all repair conditions are discovered within 180 days of completion of the assessment.
2. Procedures to ensure that all anomalies are correctly categorized in accordance with the repair provisions of the rule ("immediate repair," 60-day, 180-day, and "other" conditions).
3. Procedures that define the time at which the discovery of an anomaly occurs.
4. Procedures that define actions to be taken if the review cannot be completed within 180 days of assessment completion. (The rule specifically requires that the operator demonstrate that discovery within 180 days is impracticable and document this justification.)

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);
	452 (h) (2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.
	452 (h) (4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions* ... (ii) *60-day conditions* ... (iii) *180-day conditions* ... (iv) *Other conditions*....

3.05 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.05 Inspection Issues Summary

3.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.05 Inspection Notes

Protocol # 3.06	**Integrity Assessment Results Review: Hydrostatic Pressure Testing**
Protocol Question	For integrity assessments using hydrostatic pressure testing, has the operator reviewed the test results to determine whether the failures experienced imply that additional assessment activities are needed? ______________________ Review hydrostatic pressure test records to verify that the test complied with Subpart E requirements, that the test results were valid, and that the causes of all test failures were determined.

An effective operator program would be expected to have the following characteristics:

1. Documentation of test records sufficient to allow compliance with Subpart E requirements to be verified.
2. Test procedures and records that document the basis for test acceptance and test validity.
3. Documentation and evaluation of hydrostatic pressure test failures to understand the cause of the failure (e.g., was the failure due to hook cracks, selective seam corrosion, internal corrosion, etc?).
4. Metallurgical evaluation of test failures, as required, to assure a full understanding of test failures.
5. Documented evidence that the operator has an effective corrosion control program and that corrosion control is being effectively applied to the assessed pipeline.
6. Identification, documentation, and analysis of pressure reversals to determine the cause of pressure reversals and identify any integrity threats indicated by the pressure reversals.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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)
	452 (j) (5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (ii) Pressure test conducted in accordance with subpart E of this part;

3.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.06 Inspection Issues Summary

3.06 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.06 Inspection Notes

Protocol # 3.07	**Integrity Assessment Results Review: Results from the Application of Other Assessment Technologies**
Protocol Question	For assessments using "other assessment technology," is the operator's process for evaluation of the results adequate to identify integrity threats? ______________________ Review selected assessment records for assessments conducted using "other technology" to verify that all anomalous conditions or potential defects (including the cause) were analyzed and documented, and that appropriate, timely corrective action was taken.

An operator that chooses to use "other technology" for its integrity assessments is expected to have a documented process to assure that the chosen technology will result in a level of understanding of a pipeline's condition, equivalent to that obtained through the use of accepted ILI tools or a hydrostatic pressure test. An effective operator program would be expected to have the following characteristics:

1. Criteria for the selection of other technology that support major integrity decisions, such as (a) identification of minimum data analysis required, (b) data integration requirements prior to the assessment, (c) assignment of priority to excavations, (d) number of excavation digs required, (e) basis for assessing applicability (e.g., some direct assessment techniques may detect external corrosion but not internal corrosion), and (f) validity of assessment results.
2. Procedures that adequately implement industry accepted practices for the successful use of the technology, including conformance to applicable consensus industry standards.
3. Procedures that address the method by which validation of the results of assessments using alternative technology is conducted.
4. Provisions for identification of excavations required to validate other technology results.
5. Provisions for conducting excavation digs that support the applicability and validity of the assessment technology (as a result, additional information may need to be collected beyond the information that the operator typically collects during an excavation, depending on the specifics of the "other technology" selected).
6. Procedures must address reporting requirements and timing of discovery (180 days from completion of the assessment) and repair conditions (per paragraph 452(h)).

[For review of external corrosion direct assessment (ECDA) refer to protocols 7.03, and 7.05-7.08.]

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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)
	452 (j) (5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

3.07 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

3.07 Inspection Issues Summary

3.07 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

3.07 Inspection Notes

Integrity Management
Inspection Protocol 4

Remedial Action

Scope:

This Protocol addresses the operator's remediation of conditions identified through integrity assessments and information analysis that could affect the integrity of a pipeline segment. This includes the process to repair or remediate these conditions in such a manner to assure they will not jeopardize public safety or environmental protection, and to determine if the operator has implemented this remediation process effectively.

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Protocol # 4.01	**Remedial Action: Process**
Protocol Question	Does the operator’s Integrity Management Program include a documented process to assure prompt action to address all anomalous conditions that could reduce a pipeline’s integrity that are discovered through the integrity assessment or information analysis?

The rule requires the operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. An effective operator program would be expected to contain the following characteristics:

1. A requirement to develop a prioritized schedule for remediation of all identified repair conditions consistent with the repair criteria and time frames found in §195.452 (h).
2. A requirement to document justification for changes to the repair/remediation schedule including demonstration that such changes will not jeopardize public safety or environmental protection.
3. A requirement to notify PHMSA if the operator cannot meet the schedule for evaluation and remediation and cannot provide safety through a temporary reduction in operating pressure.
4. A requirement that if an immediate repair condition is identified, the operating pressure of the affected pipeline be temporarily reduced in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or the pipeline be shutdown until the condition is repaired. If the formula of Section 451.7 is not applicable to the type of anomaly, or would produce a higher operating pressure, the process must identify alternative acceptable methods of calculating a safe operating pressure.
5. A requirement that any temporary reduction in operating pressure taken until repair or remediation can be completed cannot exceed 365 days without the operator taking further remedial actions to ensure the safety of the pipeline. When a pressure reduction exceeds 365 days, the operator must notify PHMSA and explain the reasons for the delay.
6. A requirement that the operator comply with §195.422 when making a repair.
7. Specification of the records to be generated during the remediation process.

Rule Requirement	§195.452 (h) (1) *General requirements*. An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair. (i) *Temporary pressure reduction*. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h) (3) of this section and cannot provide safety through a temporary reduction in operating pressure. (ii) *Long-term pressure reduction*. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.
	§195.452 (h) (3) *Schedule for evaluation and remediation*. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation.... the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.
	§195.452 (h) (4) *Special requirements for scheduling remediation*. *Immediate repair conditions*.... To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4, if applicable. If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure…

4.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

4.01 Inspection Issues Summary

4.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

4.01 Inspection Notes

Protocol # 4.02	Remedial Action: Implementation
Protocol Question	Has the operator adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis?

The rule requires that an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. The inspection should ensure that:

1. A prioritized schedule was prepared by the operator for remediation of anomalous conditions.
2. Repairs were made in accordance with the operator's prioritized schedule and within the time frames allowed in §195.452 (h).
3. Changes to the schedule were justified by the operator and the schedule changes were demonstrated not to jeopardize public safety or environmental protection.
4. PHMSA was notified in those cases where the schedule for evaluation and remediation could not be met and safety could not be provided through a reduction in operating pressure.
5. For an immediate repair condition, operating pressure was reduced or the pipeline was shutdown.
6. For an immediate repair condition, temporary operating pressure was determined in accordance with the formula in Section 451.7 of ASME/ANSI B31.4, if applicable. If Section 451.7 was not applicable to the type of anomaly or produced a higher operating pressure, an alternative acceptable method was used to calculate the amount of pressure reduction.
7. Operating pressure was not reduced for more than 365 days without the operator notifying PHMSA explaining the reasons for the delay, and taking further remedial action to ensure the safety of the pipeline.
8. Repairs were performed in accordance with §195.422 and applicable industry standards.
9. Based on remediation information reviewed during the inspection, the data in Part J (Integrity Inspections Conducted and Actions Taken Based on Inspection) of the most recent Form PHMSA F 7000-1.1 appear valid and completed per Instructions for Completing Form PHMSA F 7000-1.1.

Rule Requirement	§195.452 (h) (1) *General requirements*. An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with §195.422 when making a repair. (i) *Temporary pressure reduction*. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure. (ii) *Long-term pressure reduction*. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.
	§195.452 (h) (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation ... the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

	§195.452 (h) (4) *Special requirements for scheduling remediation Immediate repair conditions*.... To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4, if applicable. If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure...

4.02 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

4.02 Additional Data *(Type an **X** in the applicable box to verify task completion.)*	
	Annual Report Part J Data of the Most Recent Form PHMSA F 7000-1.1 Reviewed

4.02 Inspection Issues Summary

4.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

4.02 Inspection Notes

Integrity Management
Inspection Protocol 5

Risk Analysis

Scope:

This Protocol addresses the overall risk analysis/information analysis process employed by operators to support various integrity management program elements, including Baseline Assessment Plan development, continuing evaluation and assessment of pipeline integrity, and identification of preventive and mitigative measures. The Protocol addresses the comprehensiveness of the risk analysis process, the methods of combining/integrating risk information, input information, the subdividing of pipelines for risk analysis, results, the risk analysis of facilities, and implementation of the risk analysis process. Evaluations of application-specific risk analyses are performed in the respective Protocol area in which they are utilized.

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Protocol # 5.01	**Risk Analysis: Comprehensiveness of Approach**
Protocol Question	Does the operator's process for evaluating risk require consideration of all relevant risk categories and operating conditions when evaluating pipeline segments?

At the onset of examining the operator's process for evaluating risk, it is important to establish the general categories of risk factors that the operator has included in their process. To that end, this protocol question addresses the overall comprehensiveness of the risk evaluation process. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
   - external and internal corrosion
   - stress corrosion cracking
   - materials problems
   - third party damage
   - operator or procedures errors
   - equipment failures
   - natural forces damage
   - construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
   - health and safety impact
   - environmental damage
   - property damage
3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process.
4. Consideration of the risks associated with alternate modes of operation of their pipelines (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.).

Note: The Protocols are organized such that verification of the use of specific required risk factors in various parts of the rule (e.g., risk factors required for assessment scheduling) is done as part of the protocols for each respective part of the rule, as follows:

Baseline Assessment Plan Factors: Protocol Question 2.02
Continual Assessment Plan Factors: Protocol Question 7.01 and 7.02
Preventive & Mitigative Risk Analysis: Protocol Question 6.02
Leak Detection Evaluation Factors: Protocol Question 6.04
EFRD Evaluation Factors: Protocol Question 6.06

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(i)(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: ....

5.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.01 Inspection Issues Summary

5.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

5.01 Inspection Notes

Protocol # 5.02	Risk Analysis: Integration of Risk Information
Protocol Question	Does the process for evaluating risk appropriately integrate the various risk factors and other information utilized to characterize the risk of pipeline segments?

Methods to evaluate risk utilize a variety of input data to characterize the physical condition of pipelines and the surrounding population/environment for which consequences are estimated. This information, including "risk factors," is typically combined in some fashion (e.g., input into an algorithm or mathematical model, evaluated by subject matter experts, etc.) to produce an estimate of the risk for a particular section of pipe. In some methods used to combine risk information, numerical "weights" are applied to risk factors when calculating or estimating risk. An effective operator program would be expected to have the following characteristics:

1. Inclusion of the appropriate variables needed to adequately determine the relevant risk ranking of a pipeline segment (e.g., variables to determine the potential for area-specific external and internal corrosion, mechanical damage, construction defects, etc.).
2. A technically justifiable basis for the analytical structure of any tools, models, or algorithms utilized to integrate risk information, and recognition of any limitations of these analytical structures.
3. Logical, structured, and documented processes and guidelines for any subject matter expert evaluations that are used to perform or influence the integration of risk information.
4. Justification for the relative magnitude of any numerical weights used to estimate measures of risk.
5. A risk integration/combination process that emphasizes the potential risk to human health and the environment as compared to "non-safety" risk factors such as those principally associated with business and economic risks.
6. In cases where a risk model is utilized, a method that integrates the risk model output with any important risk factors that were not included in the model to provide a more complete evaluation of the risk.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* ....
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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);
	§452(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 ....
	§195.452(i)(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: ....

5.02 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.02 Inspection Issues Summary

5.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

5.02 Inspection Notes

Protocol # 5.03	**Risk Analysis: Input Information**
Protocol Question	Are adequate and appropriate data and information input into the risk analysis process?

The overall quality and usefulness of a risk evaluation processes are highly dependent on the validity and quality of input data and information. An effective operator program would be expected to have the following characteristics:

1. Use of the most accurate available data to represent pipeline characteristics in the analysis of different segments, including the results of integrity assessments.
2. Controls to provide assurance of the completeness and quality of input information.
3. Guidance to minimize the use of input information that is unnecessarily or excessively conservative (to avoid masking best-estimate risk insights).
4. Use of sources best suited to provide whatever subjective information is used (e.g., from operator personnel, including field units).
5. Use of a sufficiently structured process for obtaining subjective information (e.g., using forms, surveys, interviews, quality checks, etc.) to ensure that consistent information is provided for different segments.
6. Use of the operator's and industry's collective operating experience data where applicable.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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);
	§452(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 ....
	§195.452(i)(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: ....

5.03 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.03 Inspection Issues Summary

5.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

5.03 Inspection Notes

Protocol # 5.04	Risk Analysis: Risk Analysis of Segments that Could Affect HCAs
Protocol Question	Does the operator's risk analysis approach adequately represent and consider the variation in risk factors along the line such that segment-specific risk results and insights are obtained?

The manner in which a pipeline is subdivided for the evaluation of risk is an important factor when considering the results of the analysis. An effective operator program would be expected to have the following characteristics:

1. The ability to clearly differentiate the relative risks of different pipeline segments. [Note: The manner in which a pipeline is divided up for the purposes of risk analysis may sometimes differ from "sections" established for segment identification and/or assessment schedules.]
2. An approach for applying risk factors to a pipeline subdivision unit when the factors differ across the unit.
3. A method for relating the subdivision of the pipeline used in risk analysis to: (1) the sectioning of the pipeline defined for the operator's integrity assessments and (2) the segments that can affect high consequence areas.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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);
	§452(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 ....
	§195.452(i)(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: ....

5.04 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.04 Inspection Issues Summary

5.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

5.04 Inspection Notes

Protocol # 5.05	**Risk Analysis: Results**
Protocol Question	Are results of the process to evaluate risk useful for drawing conclusions and insights in the operator's Integrity Management Program decision making?

Examination of the application of risk analysis results to specific areas is covered separately in the protocol questions for each applicable Integrity Management program element (e.g., assessment scheduling, preventive and mitigative measures). Overall characteristics of risk results, however, can be examined on a general basis. An effective operator program would be expected to have the following characteristics:

1. Identification of the pipeline locations having the highest estimated risk.
2. Identification of the most important risk drivers for the highest risk locations (e.g., third party damage, internal corrosion, etc.) and the underlying causes (e.g., what conditions are elevating the risk of internal corrosion).
3. A means to evaluate and reduce major sources of uncertainties in the process of evaluating risk. [Examples of areas of uncertainty include data and information limitations, subject matter expert opinions, risk model assumptions, and analytical techniques.]

Rule Requirement	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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);
	§452(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 ....
	§195.452(i)(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: ....

5.05 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.05 Inspection Issues Summary

5.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

5.05 Inspection Notes

Protocol # 5.06	Risk Analysis: Facilities
Protocol Question	Are technically adequate approaches used to identify and evaluate the risks of facilities that can affect HCAs?

In addition to line pipe, associated facilities that can affect HCAs are also included in the scope of the Integrity Management rule. While the integrity assessment provisions of the rule apply only to the line pipe, the other provisions of the rule apply to pump stations, break-out tanks, and other equipment if a failure at these locations could affect a high consequence area. Thus, an operator's integrity management program should include processes for addressing these facilities, including the integration of all available information affecting the likelihood and the consequences of equipment or facility failures (i.e., a risk analysis). An effective operator program would be expected to have the following characteristics:

1. Clear documentation of the operator's approach for evaluating the risk of facilities that can affect HCAs.
2. Results that facilitate the determination of measures to reduce facility risks.

Rule Requirement	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (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);
	§195.452(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.

5.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

5.06 Inspection Issues Summary

5.06 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

5.06 Inspection Notes

Integrity Management
Inspection Protocol 6

Preventive and Mitigative Measures

Scope:

This Protocol addresses the evaluation of preventive and mitigative measures, and is divided into three parts:

1. Questions applicable to all areas of the preventive and mitigative measures evaluation, including risk analysis requirements (§194.452(i)(1)-(i)(4));

2. Questions specific to the evaluation of leak detection system capabilities and the need for upgrades (§194.452(i)(3));

3. Questions specific to the evaluation of the need for installation of additional EFRDs (§194.452(i)(4)).

Note: While this Protocol addresses the specific requirements for application of risk analysis to the evaluation of preventive and mitigative measures, the overall adequacy of the operator's risk analysis process is separately covered in Protocol Area 5, Risk Analysis.

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Protocol # 6.01	Preventive & Mitigative Measures: Actions Considered
Protocol Question	Does the process to identify additional preventive and mitigative actions include consideration of risk and cover a spectrum of alternatives? [Note: Leak detection and EFRDs are covered in more detail in subsequent questions within this protocol.] ——————————— Do operator records provide documentation of the preventive and mitigative actions that have been considered?

The integrity management rule requires operators to "take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area." An effective operator program would be expected to have the following characteristics:

1. Identification of the most significant causes/drivers of segment-specific risk (e.g., third party damage, internal corrosion, etc.) when evaluating additional preventive and mitigative actions.
2. Identification of potential preventive and mitigative actions that address the most significant segment-specific risks, including consideration of preventive and mitigative actions listed in §195.452(i)(1).
3. Review of the effectiveness of current preventive and mitigative actions and the potential for enhancements and upgrades.
4. Consideration of a spectrum of modifications, ranging from incremental improvements to major changes.
5. Consideration of changes to both documented work processes (e.g., procedures, response plans) and physical changes.
6. Consideration of additional preventive and mitigative actions for non-pipe facilities that can affect an HCA.
7. Consideration of alternate modes of operation i.e., startup, shutdown, pressure cycling, etc.
8. Evaluation of additional preventive and mitigative measures in a timely manner (e.g., within one year) after integrity assessments are conducted on a segment or other events occur that indicate a need for re-evaluation (e.g., unsatisfactory detection or mitigation of an actual leak).

Rule Requirement	§195.452 (f) *What are the elements of an integrity management program?* (6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph of this section)
	§195.452(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.

6.01 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.01 Inspection Issues Summary

6.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	Rev.	Date	Document Title

6.01 Inspection Notes

Protocol # 6.02	**Preventive & Mitigative Measures: Risk Analysis Application**
Protocol Question	Does the process effectively evaluate the effects of potential actions on reducing the likelihood and consequences of pipeline releases? —————————— Verify that the operator has used the risk analysis process to evaluate preventive and mitigative measures.

Operators must conduct a risk analysis as part of the evaluation of preventive and mitigative measures, including a number of specific risk factors. In addition to the required set of factors, there are other factors that are relevant to the preventive and mitigative measures evaluation. An effective operator program would be expected to have the following characteristics:

1. Consideration of all risk factors required by §195.452(i)(2) in the risk analysis applied to the preventive and mitigative measures evaluation. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. Risk analysis variables are defined such that the impact of preventive and mitigative measures on risk to pipeline segments can be evaluated.
3. Measures to assure that the analysis is up to date prior to use (e.g., pipeline data and configuration assumptions verified to be current prior to evaluating the relative impact of a proposed preventive or mitigative measure).

Rule Requirement	§195.452(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 ... (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.

6.02 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.02 Inspection Issues Summary

6.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

6.02 Inspection Notes

Protocol # 6.03	**Preventive & Mitigative Measures: Decision Basis**
Protocol Question	Does the process provide an adequate basis for deciding which candidate preventive and mitigative actions are implemented? ———————————— Do operator records indicate that the decision making process has been applied as described?

The process and decision criteria used by an operator to decide if potential actions are to be implemented or rejected are a critical part of the preventive and mitigative measure process. An effective operator program would be expected to have the following characteristics:

1. A systematic decision-making process involving input from relevant parts of the organization such as operations, maintenance, engineering, corrosion control, etc., that considers the results of the risk analysis along with other information in making decisions about which preventive and mitigative actions to implement.
2. Priority in schedule and scope for additional actions on the highest risk lines and facilities.
3. A defined basis for decision making that includes the benefit (e.g., risk reduction, reduction in threat to integrity, etc.) preventive and mitigative measures are expected to produce.
4. Integration of approved preventive and mitigative actions with the operator's work processes responsible for scheduling and implementing the approved actions (e.g., budgeting, project management, maintenance).
5. Documentation of candidate preventive and mitigative measures that have been considered, including those that have not been implemented.
6. Implementation of approved additional actions as previously planned and scheduled.

Rule Requirement	§195.452(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 ....

6.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.03 Inspection Issues Summary

6.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

6.03 Inspection Notes

Protocol # 6.04	Leak Detection Capability Evaluation: Evaluation Factors
Protocol Question	Does the process for evaluating leak detection capability adequately consider all of the §195.452(i)(3)-required factors and other relevant factors? ———————————— Do operator records indicate that all required and other relevant factors have been evaluated?

As part of the leak detection-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there are other factors that are relevant to the evaluation of the operator's leak detection capability. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all eight of the required §195.452(i)(3) evaluation factors, including risk assessment results. If all required factors are not considered, a documented basis for the exclusion of certain listed factors. [Note: Risk analysis details are covered in protocol question 6.02.]
2. Identification and evaluation of a sufficient spectrum of leak scenarios to adequately determine the overall effectiveness of leak detection capability (e.g., "most likely" in addition to "maximum possible").
3. Consideration of additional evaluation factors such as:
   - current leak detection method for the HCA areas,
   - use of SCADA,
   - thresholds for leak detection,
   - flow and pressure measurement,
   - specific procedures for lines that are idle but still under pressure,
   - additional leak detection means for areas in close proximity to sole source water supplies, and
   - leak detection testing (such as physical removal of product from the pipeline).
4. Evaluation of all modes of line operations including slack line, idled line, and static conditions.
5. If a computational pipeline monitoring technique is part of the leak detection systems, design, maintenance, controller training, and record-keeping aspects of API 1130 are addressed in system design and maintenance practices.
6. Evaluation of leak detection performance during transient conditions, and a strategy to manage any short-term reduced performance.
7. Evaluation of the operational availability and reliability of the leak detection systems, and the operator's process to manage system failures.
8. Consideration of enhancements to existing leak detection capability (e.g., increasing the monitoring frequency of existing techniques).
9. Consistent application of a risk-based decision-making process for leak detection, as described in protocol question 6.03.

Rule Requirement	§195.452 *What preventive and mitigative measures must an operator take to protect the high consequence area?* (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 high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

6.04 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.04 Inspection Issues Summary

6.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

6.04 Inspection Notes

<table>
<tr><td>Protocol # 6.05</td><td>Leak Detection Capability Evaluation: Operator Actions/Reactions</td></tr>
<tr><td>Protocol Question</td><td>Does the process adequately consider and document operator actions and reactions associated with leak detection systems?</td></tr>
<tr><td colspan="2">The role of operations personnel is critical in responding to leak detection indications as well as making certain that leak detection systems are operating correctly. An effective operator program would be expected to have the following characteristics:

1. A documented basis for all operator reactions credited in the leak detection evaluation (e.g., operational procedures and/or training materials). [Note: This does not imply that integrity management-specific operator procedures and/or training are anticipated. Operator responses assumed in the leak detection evaluation, however, should be based on verifiable operational expectations versus arbitrary assumptions.]
2. Measures applied to assure that required actions are accomplished and prudently restored if varying modes of pipeline operations require controllers or other personnel to engage/activate or mute/disable certain attributes of the overall leak detection capabilities.
3. Integration of emergency response procedures and incident mitigation plans with associated leak detection indications.
4. Adequate guidance in documented work processes to assure that operating personnel have the authority and responsibility to initiate reaction measures and to shutdown the pipeline if warranted.
5. Assurance that supervision is always promptly available for contact if procedures require that operating personnel contact supervision prior to initiating response actions and/or shutting down the pipeline.</td></tr>
<tr><td>Rule Requirement</td><td>§195.452(i) What preventive and mitigative measures must an operator take to protect the high consequence area? (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 high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.</td></tr>
</table>

6.05 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.05 Inspection Issues Summary

6.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

6.05 Inspection Notes

Protocol # 6.06	EFRD Need Evaluation: Factors
Protocol Question	Does the process for evaluating the need for additional EFRDs adequately consider all of the 195.452(i)(4)-required factors and other relevant factors? ——————————— Do operator records indicate that all required and other relevant factors have been evaluated?

As part of the EFRD-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there may be other factors that are relevant to the evaluation of the need for additional EFRDs. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all ten of the required 195.452(i)(4) evaluation factors, including consideration of the benefits of reduced consequences expected due to reducing spill size. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. Consideration of any additional relevant line-specific factors beyond those listed in 195.452(i)(4) (e.g., the relative reliability of existing or proposed EFRDs, any relevant operating modes beyond nominal full flow conditions, etc.).
3. Consideration of risk analysis results, including identification of highest risk segments. [Note: Risk analysis details are covered in protocol question 6.02.]
4. As part of the "swiftness of leak detection and pipeline shutdown capabilities" factor, consideration of system detection times, operator response times, remotely controlled valve response characteristics, and system isolation time assessments, as applicable.
5. Evaluation of the need for additional EFRDs to respond to releases during transient conditions.
6. Consideration of the potential effects of additional EFRDs, including a) conducting proper valve sequencing during intended EFRD activations, b) the operator's ability to promptly detect and react to inadvertent EFRD activations, and c) possible elevated pressures caused by transient conditions during EFRD activations.
7. Consistent application of a risk-based decision-making process for additional EFRDs, as described in protocol question 6.03.

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (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 the nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

6.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

6.06 Inspection Issues Summary

6.06 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

6.06 Inspection Notes

Integrity Management
Inspection Protocol 7

Continual Process of Evaluation and Assessment

Scope:

This Protocol covers the requirements for conducting periodic integrity assessments based on the results of operator evaluations of pipeline integrity. This Protocol addresses the adequacy of re-assessment methods and intervals, compliance with the 5-year maximum re-assessment interval, and adequacy of any notifications for variance from the 5-year interval.

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Protocol # 7.01	Continual Process of Evaluation and Assessment: Periodic Evaluation
Protocol Question	Does the operator have an adequate process for performing periodic evaluations of pipeline integrity? __________________ Verify that the operator is performing periodic evaluations of pipeline integrity on a technically justified frequency.

An operator must have an approach to periodically evaluate pipeline integrity. The periodic evaluation process must include the following provisions:

1. An evaluation of pipeline integrity that is performed periodically to update the operator's understanding of pipeline condition and the segment-specific integrity threats for segments that can affect HCAs.
2. Periodic evaluation intervals that are based on risk factors associated with the pipeline, including those specified in §195.452 (e).
3. Consideration of:
    a. Results of the baseline assessment and re-assessments,
    b. The information analysis (risk analysis) required by paragraph §195.452 (g),
    c. Remediation decisions/actions taken, and
    d. Prior and pending decisions about preventive and mitigative actions.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
	§195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area. (2*) Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and of this section).

7.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.01 Inspection Issues Summary

7.01 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.01 Inspection Notes

Protocol # 7.02	Continual Process of Evaluation and Assessment: Re-assessment Intervals
Protocol Question	Does the operator have an adequate process for determining re-assessment intervals for pipeline segments that could affect HCAs? ________________________ Verify that re-assessment intervals are consistent with the risks identified for the pipeline and the results of previous assessments.

An operator must have an approach to determine future integrity assessment plans. The re-assessment process must include the following provisions:

1. Re-assessment intervals that are based on all risk factors associated with the pipeline and adequately consider the risk factors listed in §195.452 (e).
2. Re-assessment intervals that consider analysis of results from the last integrity assessment.
3. Re-assessment intervals that are determined using all information obtained on the condition of the pipeline as required by §195.452 (g).
4. Segments that are to be re-assessed on a maximum five-year interval, not to exceed 68 months, unless notification has been submitted to PHMSA (see 7.04).

[For review of reassessment intervals for external corrosion direct assessment (ECDA), refer to Protocol 7.08.]

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); §195.452 (g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure.
	§195.452 (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. (3) *Assessment Intervals.* An operator must establish five year intervals, not to exceed 68 months, 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.

7.02 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.02 Inspection Issues Summary

7.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.02 Inspection Notes

Protocol # 7.03	Continual Process of Evaluation and Assessment: Assessment Methods
Protocol Question	Are the assessment methods shown in the continual assessment plan appropriate for the pipeline specific integrity threats?

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process should exhibit the following characteristics:

1. The assessment methods selected for each segment are appropriate for the specific integrity threats identified for the segment through the updated risk analysis, periodic evaluations, previous assessments, and industry experience.
2. The process for assessment method selection includes consideration of completed assessment results.
3. If ILI tools are used, they are capable of detecting corrosion and deformation anomalies including dents, gouges and grooves.
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. If external corrosion direct assessment (ECDA) is the selected method, the operator must have a complete ECDA Plan that addresses the requirements of NACE RP0502-2002. [Note that review of specific ECDA plan details are covered under Protocols 7.05-7.08.] In addition, the operator is expected to address:
    a. A formal, documented process to ensure that individuals who implement and evaluate ECDA assessments are qualified to perform that work. Characteristics of an effective process include:
        i. A means to identify qualification requirements for the various ECDA steps,
        ii. Documentation that demonstrates the individual's qualifications and proficiency, and
        iii. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.
    b. Requirements established by the operator for any vendors conducting ECDA assessment activities (e.g., indirect inspection) to assure that the vendors understand their responsibilities in performing integrity assessments that comply with this rule.
6. If technology other than pressure testing, external corrosion direct assessment, or in-line inspection is planned for use, the operator submits a notification to PHMSA at least 90 days before conducting the assessment.

An effective operator program would be expected to have the following characteristics:

1. For line segments that are being hydrostatically tested, the operator performs a comprehensive review of corrosion control program effectiveness for these locations.
2. If the operator has reason to suspect a pipeline segment is susceptible to cracks or has exhibited crack-like features, the re-assessment method selection process should address assessment of cracks.
3. If the operator has reason to suspect a pipeline segment is susceptible to internal corrosion, the re-assessment method selection and subsequent data integration should address this threat.
4. The methods used to conduct re-assessments are periodically reviewed and modified if necessary based on new insights from baseline assessments, the results of information integration and risk analysis, and to allow use of new, improved assessment technologies.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) 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).

	§195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. (i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves; (ii) Pressure test conducted in accordance with subpart E of this part; (iii) External corrosion direct assessment in accordance with §195.588; or (iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conduction the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

7.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.03 Inspection Issues Summary

7.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

7.03 Inspection Notes

Protocol # 7.04	Continual Process of Evaluation and Assessment: Assessment Interval Variance
Protocol Question	Does the operator's IM Program include provisions for submitting variance notifications to PHMSA for assessment intervals longer than the 5-year maximum assessment interval?

The Rule contains provisions for exceeding a 5 year re-assessment interval under certain circumstances. If an operator desires a variance from the 5 year interval, it must notify PHMSA of its intentions. The notification must be based upon an engineering analysis or the unavailability of the technology to be used for the assessment. The operator's notification to PHMSA must contain the following characteristics:

1. Engineering Justification Requirements
   - Notification time frame - 270 days before the end of the five year re-assessment deadline;
   - Describe use of other technology such as external monitoring to provide equivalent understanding of the condition of the line pipe; and,
   - Propose an alternate interval.
2. Unavailable Technology Requirements
   - Notification time frame - 180 days before the end of the five year re-assessment deadline;
   - Demonstrate interim actions to evaluate integrity of pipeline segment; and
   - Provide an estimate of when assessment can be completed.

An effective operator program would be expected to have the following characteristics:

1. The operator's IM Program contains requirements for technically rigorous and documented engineering justifications for extending assessment intervals.
2. Evaluation of historical and current integrity information is performed to determine a new assessment interval period.
3. The operator pro-actively identifies and addresses issues that could adversely impact meeting assessment schedules.
4. The operator's IM Program adequately documents justifications for extending assessment intervals due to unavailable technology.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
	§195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (4) *Variance from the 5-year intervals in limited situations - Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j) (5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section. (ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address…

7.04 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.04 Inspection Issues Summary

7.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.04 Inspection Notes

<table>
<tr><td>Protocol # 7.05</td><td>Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Pre-Assessment</td></tr>
<tr><td>Protocol Question</td><td>Verify that the ECDA pre-assessment process complies with NACE RP0502-2002 Section 3 and §195.588 to (1) determine if ECDA is feasible for the pipeline to be evaluated, (2) select indirect inspection tools, and (3) identify ECDA regions.</td></tr>
<tr><td colspan="2">The ECDA process includes four basic steps; pre-assessment is the first of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the pre-assessment process, including:

1. The Plan requires adequate data to be identified and collected to support the ECDA pre-assessment, and the identification and collection of data is adequate
2. An ECDA feasibility assessment is conducted by integrating and analyzing the data collected
3. Appropriate requirements for selecting indirect inspection tools are established:
a. Minimum of 2 complementary tools must be selected such that the strength of one tool compensates for the limitations of the other tool. (Note: The operator must consider whether more than two indirect inspection tools are needed to reliably detect corrosion activity.)
b. Tools are able to assess and reliably detect corrosion activity and/or coating holidays.
c. The basis on which at least two different, but complementary, indirect assessment tools are selected is documented.
d. For selected tools that are not listed in NACE RP0502-2002 Appendix A, justification and documentation of the method’s applicability, validation basis, equipment used, application procedures, and utilization data.
4. ECDA Regions are identified based on the use of data integration results applied to specific criteria.
5. More restrictive criteria are applied when conducting ECDA pre-assessment for the first time on a pipeline segment.</td></tr>
<tr><td rowspan="2">Rule Requirement</td><td>§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);</td></tr>
<tr><td>§195.452 (j) (5) Assessment methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies
(iii) External corrosion direct assessment in accordance with §195.588;</td></tr>
</table>

	§195.588 What standards apply to direct assessment? (b) The requirements for performing external corrosion direct assessment are as follows: (1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment. (2) Pre-assessment. In addition to the requirements in Section 3 of NACE Standard RP0502-2002, the ECDA plan procedures for pre-assessment must include – (i) Provisions for applying more restrictive criteria when conducting ECA for the first time on a pipeline segment; (ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and (iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502-2002, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

7.05 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.05 Inspection Issues Summary

7.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.05 Inspection Notes

Protocol # 7.06	**Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Indirect Inspection**
Protocol Question	Verify that the ECDA indirect inspection process complies with NACE RP0502-2002 Section 4 and §195.588 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation.

The ECDA process includes four basic steps; indirect examination is the second of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the indirect assessment process, including:

1. The indirect inspection measurements are conducted in accordance with NACE RP0502-2002, Section 4.2:
   a. Identifying and clearly marking the boundaries of each ECDA region.
   b. Performing indirect inspections over entire length of each ECDA region and the inspections conform to generally accepted industry practices.
   c. Specifying and following generally accepted industry practices for conducting ECDA indirect inspections and analyzing results.
   d. Specifying physical spacing of readings (and practices for changing the spacing as needed) such that suspected corrosion activity on the segment can be detected and located.
2. Indications are properly aligned and compared with the data from each indirect inspection to characterize both the severity of indications and urgency for direct examination in accordance with NACE RP0502-2002, Sections 4.3 and 5.2.
   a. Criteria are specified for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:
      i. The known sensitivities of assessment tools
      ii. The procedures for using each tool
      iii. The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected
   b. Criteria are specified and applied for classification of the severity of each indication.
      i. Impacts of spatial errors considered when aligning indirect inspection results
      ii. Results from the indirect inspections compared and consistency of indirect inspection results determined to resolve conflicting or differing indications by the primary and secondary tools.
      iii. Comparison of indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA region definitions.
   c. For each indication identified during indirect examination, criteria specified and applied for:
      i. Defining the urgency level of excavation and direct examination of indications based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion.
      ii. Defining the excavation urgency as immediate, scheduled, or monitored.
   d. Criteria specified and applied for scheduling excavations of indication in each urgency level.
3. More restrictive criteria are applied when conducting ECDA indirect inspection for the first time on a pipeline segment.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

	§195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies (iii) External corrosion direct assessment in accordance with §195.588;
	§195.588 What standards apply to direct assessment? (b) The requirements for performing external corrosion direct assessment are as follows: (1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment. (3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include – (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; (ii) Criteria for identifying and documenting those indications that must be considered for excavation, including at least the following: (A) The known sensitivities of assessment tools; (B) The procedures for using each tool; and (C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected; (iii) For each indication identified during the indirect examination, criteria for – (A) Defining the urgency of excavation and direct examination of the indication; and (B) Defining the excavation urgency as immediate, scheduled, or monitored (iv) Criteria for scheduling excavations of indications in each urgency level.

7.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.06 Inspection Issues Summary

7.06 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.06 Inspection Notes

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<table>
<tr><td>Protocol # 7.07</td><td>Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Direct Examination</td></tr>
<tr><td>Protocol Question</td><td>Verify that the ECDA direct examination process complies with NACE RP0502-2002 Section 5 and §195.588 to determine which indications from the indirect inspections are most severe, collect data to assess corrosion activity, and remediate defects discovered.</td></tr>
<tr><td colspan="2">The ECDA process includes four basic steps; direct examination is the third of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the direct assessment process, including:

1. Excavations and data collection are performed in accordance with NACE RP0502-2002, Sections 5.3, 5.4, 5.10, and 6.4.2:
a. Excavations based on priority categories described in NACE Section 5.2.
b. Minimum requirements identified and implemented for data collection, measurements, and recordkeeping to evaluate coating condition and significant corrosion defects at each excavation location.
c. The number and location of direct examinations complies with NACE RP0502-2002, Sections 5.10 and 6.4.2.
2. Criteria are developed and applied for deciding what action should be taken if corrosion defects are discovered that exceed allowable limits (Section 5.5 of NACE RP0502-2002):
a. Determination of the remaining strength at locations where corrosion defects are found.
b. All anomalies are correctly categorized and remediated in accordance with the repair provisions of §195.452 (h) (4) (“immediate repair,” 60-day, 180-day, and “other” conditions).
3. Root cause is identified for all significant corrosion activity and identifies and reevaluates all other indications that occur in the pipeline where similar root-cause conditions exist.
a. Criteria are developed and applied if root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502-2002 provides guidance for criteria) and alternative methods of assessing the integrity of the pipeline segment are necessary.
4. Mitigation or preclusion of future external corrosion resulting from significant root causes.
5. Evaluation of indirect inspection data, results from the remaining strength evaluation, and root cause analysis to evaluate the criteria and assumptions used to:
a. Categorize the need for repairs
b. Classify the severity of individual indications
6. Criteria are developed and applied that describe how and on what basis indications are reclassified and reprioritized in accordance with the provisions specified in NACE RP0502-2002, Section 5.9.
7. Criteria are established and implemented for internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications.
8. Processes are in place to consider the use of assessment methods other than ECDA (e.g., ILI or Subpart E pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage, stress corrosion cracking) discovered during direct examination.
9. More restrictive criteria are applied when conducting ECDA direct examinations for the first time on a pipeline segment.</td></tr>
<tr><td rowspan="2">Rule Requirement</td><td>§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);</td></tr>
<tr><td>§195.452 (h) (4) Special requirements for scheduling remediation (i) Immediate repair conditions ... (ii) 60-day conditions ... (iii) 180-day conditions ... (iv) Other conditions....</td></tr>
</table>

	§195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies (iii) External corrosion direct assessment in accordance with §195.588;
	§195.588 What standards apply to direct assessment? (b) The requirements for performing external corrosion direct assessment are as follows: (1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment. (4) Direct examination. In addition to the requirements in Section 5 of NACE Standard RP0502-2002, the procedures for direct examination of indications from the indirect examination must include – (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment; (ii) Criteria for deciding what action should be taken if either: (A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard RP0502-2002 provides guidance for criteria); or (B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE Standard RP0502-2002 provides guidance for criteria); (iii) Criteria and notification procedures for any changes that affect the severity classification, the priority of the direct examination, and the time frame for direct examination of indications; (iv) Criteria that describe how and on what basis you will reclassify and reprioritize any of the provisions specified in Section 5.9 of NACE Standard RP0502-2002.

7.07 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.07 Inspection Issues Summary

7.07 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

7.07 Inspection Notes

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Protocol # 7.08	**Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Post-Assessment**
Protocol Question	Verify that the ECDA post assessment process complies with NACE RP0502-2002, Section 6 and §195.588 to (1) define reassessment intervals and (2) assess the overall effectiveness of the ECDA process.

The ECDA process includes four basic steps; direct examination is the last of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the direct assessment process, including:

1. Determination of reassessment intervals in accordance with NACE RP0502-2002, Section 6:
    a. Adequacy of remaining life calculations.
    b. Maximum re-assessment intervals for each region no more than one half the calculated remaining life.
    c. Criteria specified and applied for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE RP0502-2002.
2. Adjustment of reassessment intervals if required in accordance with §195.452 (j) (3).
3. Establishment and monitoring of performance measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion:
    a. At least one additional, randomly selected anomaly location has been excavated for process validation.
    b. Additional criteria have been established and monitored to evaluate long-term program effectiveness such as those identified in NACE RP0502-2002, Section 6.4.3.
4. Incorporation of feedback at all appropriate opportunities throughout the ECDA process to demonstrate continuous improvement.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
	§195.452 (j) (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.
	§195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies (iii) External corrosion direct assessment in accordance with §195.588;

	§195.588 What standards apply to direct assessment? (b) The requirements for performing external corrosion direct assessment are as follows: (1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment. (5) Post assessment and continuing evaluation. In addition to the requirements in Section 6 of NACE Standard RP0502-2002, the procedures for post assessment of the effectiveness of the ECDA process must include – (i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and; (ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE Standard RP0502-2002 (see Appendix D of NACE Standard RP0502-2002)

7.08 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

7.08 Inspection Issues Summary

7.08 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

7.08 Inspection Notes

Integrity Management
Inspection Protocol 8

Program Evaluation

Scope:

This Protocol addresses the requirement to measure whether the Integrity Management (IM) Program is effective in assessing and evaluating integrity and in protecting the high consequence areas. This Protocol addresses periodic internal reviews or audits of the IM Program, threat specific and aggregate program-wide performance measures, program goals, trend analysis, root cause analysis, and communication of program results and lessons learned.

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Protocol # 8.01	Program Evaluation: Process Approach
Protocol Question	Inspect the operator's IM Program to verify that it includes a process for performing IM Program evaluations as required in §195.452 (f) (7). __________________ Verify that the IM Program evaluation has been implemented in accordance with the operator's process description.

An operator's Integrity Management (IM) Program must include a process to measure whether the program is effective in assessing and evaluating pipeline integrity and in protecting the high consequence areas. The purpose of this protocol is to perform an inspection of the operator's approach to evaluate the effectiveness of its IM Program processes and methods used to perform each IM Program element in 195.452 (f). An effective operator program would be expected to have the following basic characteristics:

1. The use of periodic self assessments, internal/external audits, management reviews, performance measures, or other self critical evaluations to assess program effectiveness.
2. A description of the scope, objectives, and frequency of program evaluations.
3. Clear performance goals and objectives to measure the effectiveness of key integrity activities.
4. Clear assignment of responsibility, by organizational group or title, for implementing required actions.
5. Review and follow-up of program evaluation results, findings, and recommendations, etc., by appropriate company managers.

The adequacy of specific performance measures is the subject of Protocol 8.02.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (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.

8.01 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.01 Inspection Issues Summary

8.01 Documents Reviewed			*(Tab from bottom-right cell to add additional rows.)*
Document Number	**Rev.**	**Date**	**Document Title**

8.01 Inspection Notes

Protocol # 8.02	Program Evaluation: Performance Measures
Protocol Question	Inspect the operator's IM Program to determine if the operator has selected an adequate set of performance measures to provide meaningful insight into IM Program effectiveness.

The purpose of this protocol is to review the specific IM Program performance metrics to determine if they can reasonably be expected to effectively assess and evaluate the IM Program. An effective process for evaluating IM Program performance would be expected to include the following characteristics:

1. A description in the IM Program document of the type and frequency of performance measures to be used.
2. Overall program metrics including (a) overall measures of program effectiveness such as number of leaks, volume released, etc, and (b) measures that reflect the accomplishment of the program's objectives such as number of miles of pipeline assessed; number of anomalies found requiring repair or mitigation; number of right-of-way encroachments.
3. Threat specific metrics, such as: number of leaks caused by internal/external corrosion; anomalies from manufacturing defects; third party damage; operator error; over-fill/over-pressure (tanks); equipment or non-pipe problems.
4. Defined performance goals that address IM Program areas as well as segments specific issues related to the operator's unique operating environment such as an increase in the number, and depth, of corrosion related anomalies, an increase in the threat of mechanical damage due to an increase in one calls, a change in operations resulting in an increase in pressure cycles, an increase in the number of crack anomalies, etc.
5. Bench-marking company performance using data from outside the company (e.g., PPTS).
6. Trending of equipment or material failures as a means to evaluate pipeline deterioration (an indicator of the end of useful life of materials and components), including a method to establish the magnitude of trends that represent normal fluctuations versus significant deviations (i.e., significant enough to warrant corrective action).
7. Trending of leading indicators such as inadvertent over-pressurization, right-of-way encroachments without one-call notification, SCADA outages, operation of overpressure or other safety devices, etc.
8. A means to update the performance measures (if needed) to assure they are providing useful information about the effectiveness of IM Program activities.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (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.

8.02 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.02 Inspection Issues Summary

8.02 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*

Document Number	Rev.	Date	Document Title

8.02 Inspection Notes

Protocol # 8.03	Program Evaluation: Communication of Evaluation Results
Protocol Question	Does the Program Evaluation process require communication of goals and IM Program effectiveness to managers and workers involved with IM Program implementation?

The purpose of this protocol is to ensure that the operator adequately communicates the results of program effectiveness to the proper areas/personnel in the company that may need to utilize the information. An effective program would be expected to have the following characteristics:

1. Periodic reports on the IM Program performance that are prepared and distributed to responsible field and headquarters managers.
2. Communications of performance evaluation results that provide an accurate and thorough summary and trending of IM Program performance, as well as information on the most important integrity issues and actions taken to address these issues.
3. Management follow-up of significant integrity issues and actions taken to address these issues.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (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.

8.03 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.03 Inspection Issues Summary

8.03 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

8.03 Inspection Notes

Protocol # 8.04	Program Evaluation: Root Cause Analysis Process
Protocol Question	Does the operator have an effective root cause analysis and a lessons learned program? Is the process being effectively implemented?

The insights obtained from root cause analysis of incidents, leaks, and near-misses can be important to improving performance. The purpose of this protocol is to review the use of root cause analysis and to evaluate how lessons learned are communicated in the organization. The following characteristics would be expected to be included in an effective root cause analysis process:

1. Rigorous and complete analyses of problems affecting risk that address the identification of human factors issues, management systems problems, generic component or process failures, positive trends, and system wide implementation of good practices.
2. Rigorous and complete identification of recommendations and corrective actions; and thorough tracking and follow-up of these actions to ensure completion.
3. Lessons learned from root cause analysis of incidents developed and distributed to appropriate company employees.

Review examples involving significant problems and determine the adequacy of the analysis and proposed corrective actions. Select several proposed corrective actions from the root cause analysis that was reviewed and determine if the actions have been completed, or are scheduled for completion in a timely manner.

Rule Requirement	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (6) Follow recognized industry practices
	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (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.

8.04 Inspection Results	*(Type an **X** in the applicable box below. Select only one.)*
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.04 Inspection Issues Summary

8.04 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

8.04 Inspection Notes

Protocol # 8.05	Program Evaluation: Process Revision and Document Control
Protocol Question	Does the operator's Integrity Management Program adequately assure that document updates and revisions are identified, justified, documented, and implemented consistent with the requirements of §195.452?

The rule requires that documentation be maintained that supports the decisions and analyses made to implement the Integrity Management Program. The operator's revision and document control process should exhibit the following characteristics:

1. The operator has a comprehensive written Integrity Management Program.
2. Adequate documentation to support the decisions, analyses, and action taken to implement and evaluate each element of the integrity management program.
3. Periodic reviews of all IM Program elements (e.g., risk analysis) to determine the need for any updates
4. Adequate interfaces with other IM Program elements to assure the revisions in one area (e.g., segment identification) are reflected in the other elements (e.g., baseline assessment plan).
5. Provisions to identify and analyze changes to the pipeline (e.g., operations, material conditions) and the local terrain, environment, and population for impacts on segment identification, risk analysis and other IM Program elements
6. Adequate documentation to identify changes to the Baseline Assessment Plan, as required by §195.452 (c)(2)
7. Adequate measures for controlling documents to ensure changes are tracked and that the latest revision is being used.
8. A document retention policy that ensures key documents, as described in §195.452 (l), are retained for the life of the pipeline.
9. A policy that ensures that key Integrity Management required documentation is obtained from previous owner/operators upon acquisition of pipeline.

Rule Requirement	§195.452(b) *What program and practices must operators use to manage pipeline integrity?* (1) Develop a written integrity management program that addresses the risks on each segment of pipeline (4) Include in the program a framework that- Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and (ii) Initially indicates how decisions will be made to implement each element.
	§195.452 (c)(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.
	§195.452 (l) *What records must be kept?* (1) An operator must maintain for review during an inspection: 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.

8.05 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.05 Inspection Issues Summary

8.05 Documents Reviewed *(Tab from bottom-right cell to add additional rows.)*			
Document Number	**Rev.**	**Date**	**Document Title**

8.05 Inspection Notes

Protocol # 8.06	**Program Evaluation: Process Formality**
Protocol Question	Is the operator's Integrity Management Program documented with sufficient specificity and detail to provide assurance that it can be implemented in a technically sound and consistent manner? ______________________________ Do operator records indicate that the process has been implemented as described? The inspectors should review areas of weakness identified during the inspection against the IMP documentation.

A formal, written Integrity Management Program framework is a key element of an operator's integrity management process. After review of process details in the preceding protocol questions, the inspection team should evaluate the overall process that the operator uses to implement their Integrity Management Program. Each element of an effective operator program would be expected to have the following characteristics:

1. The requirements of the IM rule are captured.
2. The technical basis and assumptions used in each element of the program are delineated.
3. The procedures required to implement the IMP are identified.
4. There is sufficient detail and specificity to allow successful implementation of each element.
5. The responsibilities for implementing all required actions are identified (e.g., by organizational group or title).
6. The distribution of key IMP documents to appropriate individuals and organizations is defined.
7. Management involvement in key elements of the IMP is identified.
8. Documented internal review or quality assurance mechanisms are in place to assure accurate, complete, and consistent results.

Rule Requirement	§195.452(b) *What program and practices must operators use to manage pipeline integrity?* (5) Implement and follow the program.
	§195.452(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.

8.06 Inspection Results *(Type an **X** in the applicable box below. Select only one.)*	
	No Issues Identified
	Potential Issues Identified *(explain in summary)*
	Not Applicable *(explain in summary)*

8.06 Inspection Issues Summary

8.06 Documents Reviewed	(Tab from bottom-right cell to add additional rows.)		
Document Number	**Rev.**	**Date**	**Document Title**

8.06 Inspection Notes