PHSMA/ Office of the State Fire Marshal

Integrity Management Program
CFR Title 49
Part 195 and
CA Govt. Code 51010

Hazardous Liquid Integrity Management Plan
(Rev July 2017)

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Approval Document

Company Name: Carbon California

NOTE: The Company is referred to in the plan as "Operator", "operator", etc.

Company Approval: Jane Farkas, Director of Land and Regulatory affairs
(Name and Title)

11-1-18
(Signature) (Date)

Facility Approval: Luke Faith, Area Supervisor
(Name and Title)

Luke O. Faith 11-1-18
(Signature) (Date)

Rule Effective Date: February 18, 2003

Hazardous Liquid Integrity Management Plan
(Rev Jul 2017)

Record of Revisions

2017	
Document Section	**Description**
Table of Contents	Changes reflect new plan structure
Approval Document	Minor changes to format
Intro	This has been combined and renamed with "Scope, Goals, & Summary of IMP Regulations", Glossary of Terms", "Notifications", "Management of Change", "Record Keeping", and Summary of Roles and Responsibilities."
Element 1	Updated with protocols and reformatting
Element 2	Updated with protocols and reformatting
Element 3	Updated with protocols and reformatting
Element 4	Updated with protocols and reformatting
Element 5 & 8	Combined 5 and 8, updated with protocols and reformatting
Element 6	Updated with protocols and reformatting
Element 7	Updated with protocols and reformatting
IMP Protocols	This is the protocols, agenda and annual review
Action Items and Major Events	This has been combined
Team Charter	Updated and reformatted
Team Qualifications	Updated and reformatted
Remediation Schedule	Updated and reformatted
Risk Analysis	Clarification in the "How to use Risk Analysis." "Risk Analysis" worksheet has been simplified to only reflect risk scores. Also, consequences are determined from HCA analysis. No longer a line item with other threats. "Segments" tab has been reconfigured to only reflect the risk factors (threat)
Leak Detection and EFRD	Combined and reformatted

Name: Luke Faith Date: 11-1-18

Signature: Luke D. Faith

Hazardous Liquid Integrity Management Plan
(Rev July 2017)

Intro, Scope and Summary of Integrity Management Plan Requirements

This Integrity Management Plan ("IMP") outlines the procedures and methods the operator will utilize in complying with the hazardous liquid pipeline IMP regulations written in 49 CFR 195.452, Appendix C to 195.452, and latest edition of Integrity Management Inspection Protocols.

This plan 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.

Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.
(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.
(3) Category 3 includes pipelines constructed or converted after May 29, 2001.
(4) Low stress pipelines as specified in §195.12.

Each pipeline covered by 49 CFR 195.452 must a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

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

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

The Office of Pipeline Safety does not require this IMP to be submitted for review, but the IMP must be available for inspection if requested. Listed below are the required elements for the IMP. The details as to how the operator will comply with these requirements are contained in each Element.

This IMP will also utilize the latest edition of IMP inspection protocols and fishbones to support the proper implementation and documentation necessary for this IMP program. Each inspection protocol will be addressed in this IMP. The inspection protocols are included as a record and will be updated annually (along with several other records – see below), to reflect new information and/ or direct the user to another record that satisfies an IMP element. Each protocol fishbone can be found at the end of each Element.

Each Element has been mapped against the inspections protocols and can be found in the following table:

Element	Element Title	Protocols
1	Identify segments that could affect HCAs [195.452 (a), (d)(3), (f)(1)]	1.01 - 1.08
2	Baseline assessment [195.452 (c), (f)(2)]	2.01 - 2.03, 7.05 – 7.07
3	Review of assessment results [195.452 (f)(3)(g)]	3.01 - 3.07
4	Remediation and repair criteria [195.452 (f)(4)(h)]	4.01 - 4.02
5 & 8	Continuing assessment and evaluation [195.452(f)(5) (j)] & Review of Integrity Assessment Results and Data Analysis [195.452 (f)(8) (h)(2)]	5.01 - 5.07, 7.01 - 7.04, and 7.08
6	Preventive and mitigative measures [195.452 (f)(6)(i)]	6.01 - 6.06
7	Program evaluation and measuring effectiveness [195.452 (f)(7)(k)]	8.01 – 8.08

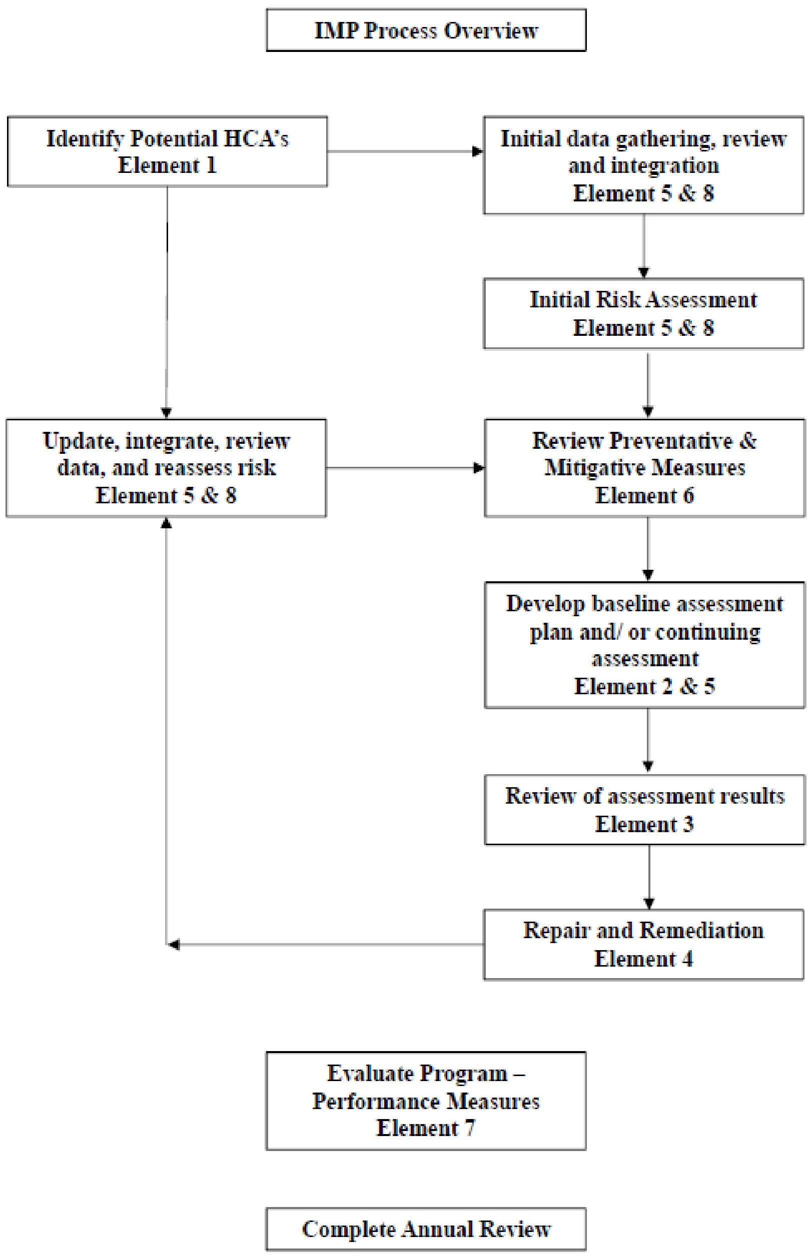
Because of the complexities related to 195.452, Appendix C, Inspection Protocols, and API 1160 “Managing System Integrity for Hazardous Liquid Pipelines” the following guidance has been provided for clarification on the process.

Annual Review:

During the annual meeting, several records should be completed. It’s important to complete the “Updated” portion of the record. The group will complete the following items:

1. Team Charter – This is the Annual Review Sign-In Sheet. Each team member will sign this document. When the meeting is completed the Sign-In Sheet and Team Charter, along with all the supporting documents, will be given to the LIMT Management Support individual for signature. This shows management support and dissemination of information throughout the organization.
2. Review Team Qualifications Requirements – The team will review these qualifications.
3. Training Plan – The team should continue to increase their knowledge of integrity management.
4. IMP Protocols – This is the Agenda and Annual Review. The team will go through and answer the questions. Areas to be covered include but are not limited to:
    a. Review any changes in HCA’s
    b. Review and update Risk Analysis (Segment Information, Preventative and Mitigative Measures, etc.)
    c. Review and update Remediation and Repair worksheet
    d. Performance Measures
5. Review and update Action Items and Major Events

Overview of IMP Process:



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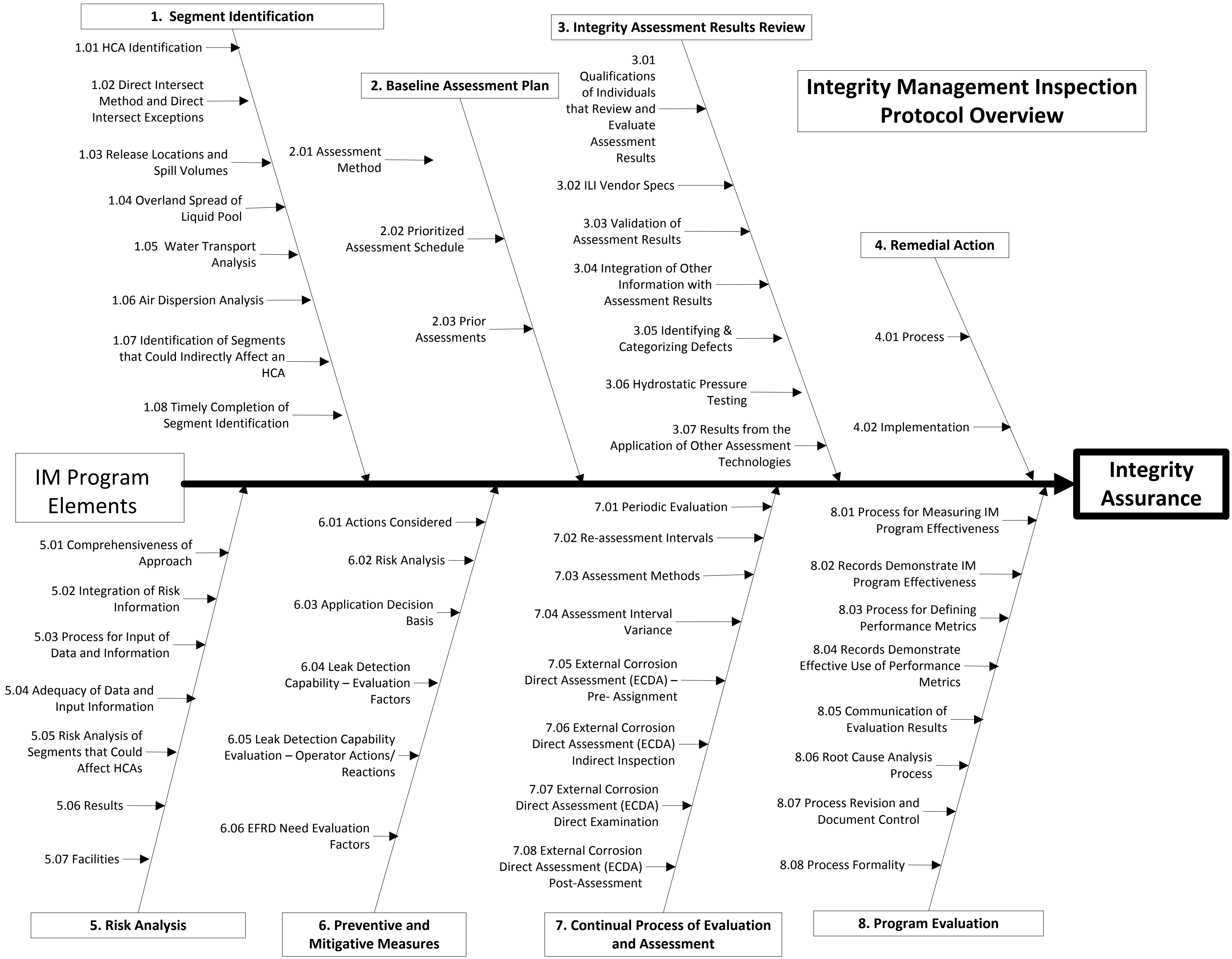
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Management of Change (MOC)

MOC procedures establish the minimum requirements to provide for the safety of the operator personnel, the public, and operator pipeline facilities due to changes or modifications in product, equipment, technology, procedures, or personnel. The operator will analyze the potential impact of changes to the pipeline facilities and will modify pipeline procedures and programs as appropriate.

MOC procedures shall assure that the following considerations are addressed:

- Impact of change on safety, health, and the environment
- Modifications to all appropriate procedures (O&M, Emergency, Operator Qualification, IMP, EHS)
- Necessary time period for the change, and Authorization requirements for the proposed change

The operator will utilize the existing MOC procedures for the IMP program. Refer to operators MOC procedures for details on the MOC process.

Summary of Roles and Responsibilities

Roles and Responsibilities can be found in the Team Charter, Team Qualifications, and the IMP Protocol Agenda and Annual Review.

Record Keeping

The purpose of this procedure is to provide guidance for recordkeeping of IMP program documents. Maps, drawings and records shall be readily available to any person requiring these documents to perform their pipeline duties. Records shall be kept consistent with Operations and Maintenance (O&M) Manual requirements.

The appropriate person, as defined in the Team Charter, Team Qualifications, and the IMP Protocol Agenda and Annual Review will generate the record as required and place in the appropriate DOT file. All records and data should be reviewed for accuracy by the IMP Leader or appropriate person.

Record Retention:

Generally, routine operations, maintenance, and operator qualification records will be kept for a minimum of five years. Construction, repair, and corrosion records will be kept for the life of the pipeline. Check you O&M for record retention times.

PHMSA Notification Requirements

This section describes when and how notifications must be made to the OPS under the IMP rule. Below is a summary of the IMP notification requirements. Notification requirements are explained in further detail on the pages following the table.

Table – Summary of Notification Requirements

Circumstance/Type	Deadline for Submittal	Information Required
Inability to meet remediation deadlines in the rule and unable to reduce pressure	When the Operator determines schedules cannot be met	Description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned
Pressure reduction will exceed 365 days	When pressure reduction exceeds 365 days	Reasons for the delay, description of additional remedial actions
Use of technology other than in-line inspection or pressure testing for conducting assessments	90 days prior to assessment	Description of "other technology", basis for concluding equivalent understanding of pipe condition, schedule for assessment
Variance from 5-year re-assessment interval (unavailable technology)	180 days before end of 5-year interval	Date and method of last assessment, reason why required interval cannot be met, interim evaluation of pipe integrity, schedule for assessment
Variance from 5-year re-assessment interval (engineering basis)	270 days before end of 5-year interval	Date and method of last assessment, proposed new retest interval, actions that will provide equivalent understanding of pipe condition, summary of engineering basis
In addition, all notifications must include information about the pipe segments and HCAs involved.		

The operator can submit notifications as specified in the rule by:

1. Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or
2. Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22321, 1200 New Jersey Ave SE., Washington, DC 20590.

Glossary of Terms and Definitions

The following definitions are derived from the U.S. Department of Transportation's Regulations in 49 CFR Part 195.452 and API #1160, Managing System Integrity.

Anomaly: A possible deviation from sound pipe material or weld. Indication may be generated by non-destructive inspection, such as in-line inspection. Definition based on NACE Technical Committee Report, "In-line Nondestructive Inspection of Pipelines." Also see; defect imperfection.

Category 1 pipelines include pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to 49 CFR 195.452. [195.452(a)(1)]

Category 2 pipelines include pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to 49 CFR 195.452. [195.452(a)(2)]

Category 3 pipelines include pipelines constructed or converted after May 29, 2001. [195.452(a)(3)]

Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction. [195.450]

Continual evaluation of a pipeline: A program for conducting periodic integrity assessments and evaluating the results of those assessments to understand the current pipeline condition and integrity issues

Discovery of a condition: The date after an internal inspection runs when an operator has adequate information about a defect, anomaly, or other pipeline feature to determine the need for repair. Depending on the circumstances, adequate information may be available when the preliminary report is completed, following an analytical evaluation that integrates information from other sources, following excavation, or following receipt or the final internal inspection report. In no case, can the date of discovery be later than the date of the final report.

Emergency flow restricting device (EFRD): A check valve or remote control valve. [195.450]

Final in-line inspection report: A report provided by the in-line inspection vendor that provides the operator with a comprehensive interpretation of the data from an in-line inspection. Also see, preliminary in-line inspection report.

High Consequence Areas (195.450):

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.

Those locations where a pipeline release might have a significant adverse effect on an unusually sensitive area (see 49 CFR 195.6), a high population area, another populated area, or a commercially navigable waterway. This definition is specific to the federal regulations in the United States, see 49 CFR 195.
[195.450]

ILI: In line inspection

Imperfection: A flaw or other discontinuity noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis. Definition based on APE 570. Also see, anomaly; defect.

Immediate repair condition: A defect or anomaly in the condition of the pipe that requires immediate action to repair/remediate. The rule identifies the following as immediate repair conditions. Operators must immediately reduce operating pressure or shut down the line until repairs of these conditions are completed:

- Metal loss greater than 80% of nominal wall regardless of dimensions
- A calculation of the remaining strength of the pipe shows predicted burst pressure less than the established maximum operating pressure at the location of the anomaly (using suitable calculation methods)
- A dent on top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking, or stress rise
- A dent located on top of the pipeline with depth greater than 6% of nominal pipe diameter
- An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action

Indication: A finding of a nondestructive testing or inspection technique. Definition based on NACE Technical Committee Report, "In-line Nondestructive Inspection of Pipelines."

Integration of data: The process of bringing together all available risk and integrity-related data and information, and evaluating the combined impact of these diverse factors on risk.

Integrity Assessment: A method for determining the pipe's current condition. Acceptable methods include internal inspection, pressure testing, or other technology that the operator demonstrates scan provide an equivalent understanding of the pipe condition.

Integrity Management Program: A documented set of policies, processes, and procedures that includes, at a minimum, the following elements:
A process for determining which pipeline segments could affect an HCA,

- A Baseline Assessment Plan;
- A process for continual integrity assessment and evaluation
- An analytical process that integrates all available information about pipeline integrity and the consequences of a failure,
- Repair criteria to address issues identified by the integrity assessment method and data analysis (the rule provides minimum repair criteria for certain, higher risk, features identified through internal inspection);
- A process to identify and evaluate preventative and mitigative measures to protect HCAs,
- Methods to measure the integrity management program's effectiveness, and
- A process for review of integrity assessment results including data analysis by a qualified individual.

Mitigation or mitigative action: Taking appropriate action based on an assessment of risk factors to reduce the risk level of a given injurious anomaly. Such action may consist of, but is not limited to further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, administrative/procedural changes, or repairs.

MOP: Maximum operating pressure.

Normal operating pressure: The predicted pressure (sum of static head pressure, pressure required to overcome friction losses, and any back pressure) at any point in a piping system when the system is operating under a set of predicted steady state conditions.

Operator: A person who owns or operates pipeline facilities. Definition based on 49 CFR Part 195.

P&ID: Piping and instrumentation diagram.

PLC: Programmable logic controller.

Preliminary in-line inspection report: A report, usually produced in a short amount of time, which provides the operator with a list of defects considered to be an immediate hazard to pipeline safety. Typically, the operator defines the actual reporting parameters. Also see, final in-line inspection report.

Preventive and Mitigative Measures: Activities designed to reduce the likelihood of a pipeline failure (preventive) and/or minimize or eliminate the consequences of a pipeline failure (mitigative). Examples of preventive measures include enhanced damage prevention practices, conducting periodic close interval surveys, or inspecting pressure relief devices more frequently.

Examples mitigative measures include the installation of emergency flow restricting devices, improving leak detection system capability, or conducting drills with local emergency responders. Reducing operating pressure is a measure that might impact both the likelihood and the consequences of a pipeline failure.

Remote control valve or RCV means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite. [195.450]

Risk: A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

Risk Factors: Parameters that can influence the likelihood and/or consequence of a pipeline release. There are many types of risk factors, including design(e.g., wall thickness, seam type), operations (e.g., maximum operating pressure, pressure cycle), maintenance and surveillance (e.g., patrolling frequency, valve maintenance practices), previous integrity assessment and repair results, operating experience (e.g., leak history, cathodic protection history), commodities being transported, emergency response procedures and preparedness, and proximity to and geo-physical features separating the pipeline from population, unusually sensitive environmental resources, and commercially navigable waters.

Unusually Sensitive Areas (USAs): Drinking water and ecological resources that are unusually sensitive to environmental damage from hazardous liquid pipeline releases. The criteria defining USAs is codified in Part 195.6.

Risk assessment: A systematic, analytical process, in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives (see Section 8).

Safe operating pressure: The pressure, calculated using remaining strength of corroded pipeline formulas, where all corroded regions will withstand a pressure equal to a stress level of 1.39 times the maximum operating pressure (MOP).

SCADA: Supervisory control and data acquisition.

Shall: The term "shall" is used in this standard to indicate those practices that are mandatory.

Should: The term "should" is used in this standard to indicate those practices which are preferred, but for which operators may determine that alternative practices are equally or more effective, or those practices for which engineering judgment is required.

Stand-up (operational) test: A pressure test to determine the leak tightness of a pipeline or pipeline segment. This test is typically conducted with product (or water) at a pressure significantly less than hydrostatic test pressure required by 49 CFR 195.304 (1.25 times maximum operating pressure [MOP]) and does not exceed the MOP of the pipe. A pipeline operator may conduct this test after a pipeline is lined up but prior to beginning the movement (delivery).

TPD: Third-party damage.

60 day condition: A defect or anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 60 days of discovery. The rule identifies the following as 60-day conditions.

- A dent located on top of the pipeline (above 4 and 8 o'clock positions) with a depth greater than 3 percent of the pipeline diameter (greater than 0.25 inches for a pipeline diameter less than NPS 12)
- A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or stress riser (NOTE: Top-of-the-pipe dents with metal loss, cracking or stress riser are an immediate repair condition)

180 day condition: A defect of anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 180 days of discovery. The rule identifies the following as 180 conditions.

- A dent with depth greater than 2% of the pipeline's diameter (0.25 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.
- A dent located on the top of the pipeline (between the 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.25inches in depth for a pipeline diameter less than NPS 12)
- A dent located on the bottom of the pipeline with a depth greater than 6 % of the pipeline's diameter
- A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly (using suitable calculatingly methods)
- An are of general corrosion with a predicted metal loss greater than 50% of nominal wall
- Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
- A potential crack indication that when excavated is determined to be a crack
- Corrosion of or along a longitudinal seam weld
- A gouge or groove greater than 12.5% of nominal

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Element 1
Identification of Pipeline Segments
That Could Affect High Consequence Areas

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Section 1.1 Introduction

This element addresses the identification of pipeline segments that could affect one or more HCAs. This element 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.

In accordance with CFR 195.452, hazardous liquid pipeline operators are required to identify each pipeline segment that could affect an HCA. **High Consequence Area ("HCA")** means commercially navigable waterway (which means a waterway where a substantial likelihood of commercial navigation exists), 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); 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), or an unusually sensitive area, as defined in §195.6.

All <u>category 1</u> pipeline companies must identify their hazardous liquid pipelines that could affect high consequence areas by **<u>December 31, 2001</u>**. Also, all category 1 pipeline companies must complete their Integrity Management Plan by **<u>March 31, 2002</u>**. A category 1 company is defined as an operator with more than 500 miles of pipeline and is subject to this regulation.

All <u>category 2</u> pipeline companies must identify their hazardous liquid pipelines that could affect high consequence areas by **<u>November 18, 2002</u>**. Also, all category 2 pipeline companies must complete their Integrity Management Plan by **<u>February 18, 2003</u>**. A category 2 company is defined as an operator with less than 500 miles of pipeline and is subject to this regulation.
For category 2 pipeline companies, at least 50% of the line pipe affecting HCAs must be assessed by **<u>August 16, 2005</u>**, beginning with the highest risk segments. Category 2 operators must complete all assessments by **<u>February 17, 2009</u>**.

All <u>category 3</u> pipeline companies must identify their hazardous liquid pipelines that could affect high consequence areas the date the **<u>pipeline begins operations.</u>** Also, all category 3 pipeline companies must update their Integrity Management Plan **<u>within one year</u>** after the date the pipeline begins operation. A category 3 includes pipelines constructed or converted after May 29, 2001.

Section 1.2 HCA Identification (Protocol 1.01)

The operator will use one or more of the following to identify, maintain up-to-date location and boundaries of HCA's:

1. National Pipeline Mapping System ("NPMS"), or equivalent sources, to identify HCAs.
2. If an operator has lines in Pennsylvania they should contact the Pennsylvania Department of Environmental Protection for guidance on potential USA's.
3. Local knowledge and 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. Google Earth
5. Digital Data on populated areas available on U.S. Census Bureau maps.
6. Geographic Database on the commercial navigable waterways available on *http://www.bts.gov/gis/ntatlas/networks.html.*
7. The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at *http://www.bts.gov/gis/ntatlas*

OPS will maintain the NPMS and update it periodically. However, the operator will still be responsible for ensuring that it has identified all high consequence areas that could be affected by a pipeline segment. The operator will also periodically (annually) evaluate its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to §195.452(d)(3).)

Section 1.3 Direct Intersect Method and Direct Intersect Exceptions (Protocol 1.02)

A segment that can impact an HCA refers to a continuous portion of a pipeline system in which the released commodity from a failure occurring anywhere between the two end points of the segment could migrate to and impact an HCA. The segment sizes shall be defined by whether or not a spill could impact the HCA and not by previous pre-set operator definitions. When the segment is within an HCA, the two end points of the segment will be identified by specific locations that represent where the pipeline actually intersects that HCA boundary. All reviews to identify HCAs will be fully documented. This means methods and assumptions will be included where applicable, especially for exceptions. Justification for exceptions will also include HVL properties, topographical considerations, type of HCA, and significant of consequences.

The operator will determine all locations where its pipeline system is located in an HCA (i.e., the operator should correlate its complete pipeline system(s) maps with the HCA maps, and identify areas where the pipeline system intersects an HCA). The operator may take an exception to any segments that directly intersect an HCA. If so, the operator will provide an adequate and convincing technical justification for that conclusion.

The operator will identify the intersections between the operator's pipeline and HCAs and the operator's technical justification for excluding any segments that directly intersect an HCA. The operator shall complete the following:

1. 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 operator shall also include pipeline facilities, not just line pipe, that are located in HCAs (pumping stations, breakout tanks, etc.).
3. Any operator GIS or other mapping software used will employ a valid analysis algorithm or methodology to identify segments that intersect HCAs.

4. Any manual analysis techniques used by the operator will 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 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:
    a. HVL properties.
    b. topographical considerations.
    c. HCA properties.

Section 1.4 Release Locations and Spill Volumes (Protocol 1.03)

The operators approach for analyzing the potential effects of pipeline failures that could affect HCAs must define potential locations on the pipeline where releases could occur. The operator should 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. The operator should 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 operators 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 operators 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.

Additional Guidance - Appendix C Guidance:

When making a determination of the impact zone and whether a pipeline segment could affect an HCA, the operator will consider the following factors when a pipeline segment is not fully located in an HCA: [Taken from Part 195 Appendix C Guidance]

1. Terrain surrounding the pipeline. The operator will consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.
2. Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.
3. Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.
4. Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway or HCA.
5. The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) A highly volatile liquid becomes gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.
6. Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
7. Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.
8. The hydraulic gradient of the pipeline.
9. The diameter of the pipeline, the potential release volume, and the distance between the isolation points.
10. Potential physical pathways between the pipeline and the high consequence area.
11. Response capability (time to respond, nature of response).
12. Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

Section 1.5 Overland Spread of Liquid Pool (Protocol 1.04)

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. The operator 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 operators 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.

Section 1.6 Water Transport Analysis (Protocol 1.05)

The operator will 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 operators 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.

Section 1.7 Air Dispersion Analysis (Protocol 1.06)

If the pipeline segment transports highly volatile liquids the operators documented consequence analysis process should include a technically adequate analysis of the air dispersion of vapors from the release of highly volatile liquids and volatile liquid to determine the extent of harmful commodity vapor spread and its effects on HCAs?

The operator process will 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.

EPAs free Aloha software modeling program can be used unless other software is more appropriate for the HCA segment. This software can be downloaded for free.

Section 1.8 Identification of Segments that Could Indirectly Affect an HCA (Protocol 1.07)

The operators analysis should adequately identify all locations of segments that do not intersect, but could indirectly affect, an HCA. The operator process will have the following characteristics:

1. The process requires that segments that could affect HCAs (according to the analysis reviewed under [Protocol 1.04] through [Protocol 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.

Section 1.9 Timely Completion of Segment Identification (Protocol 1.08)

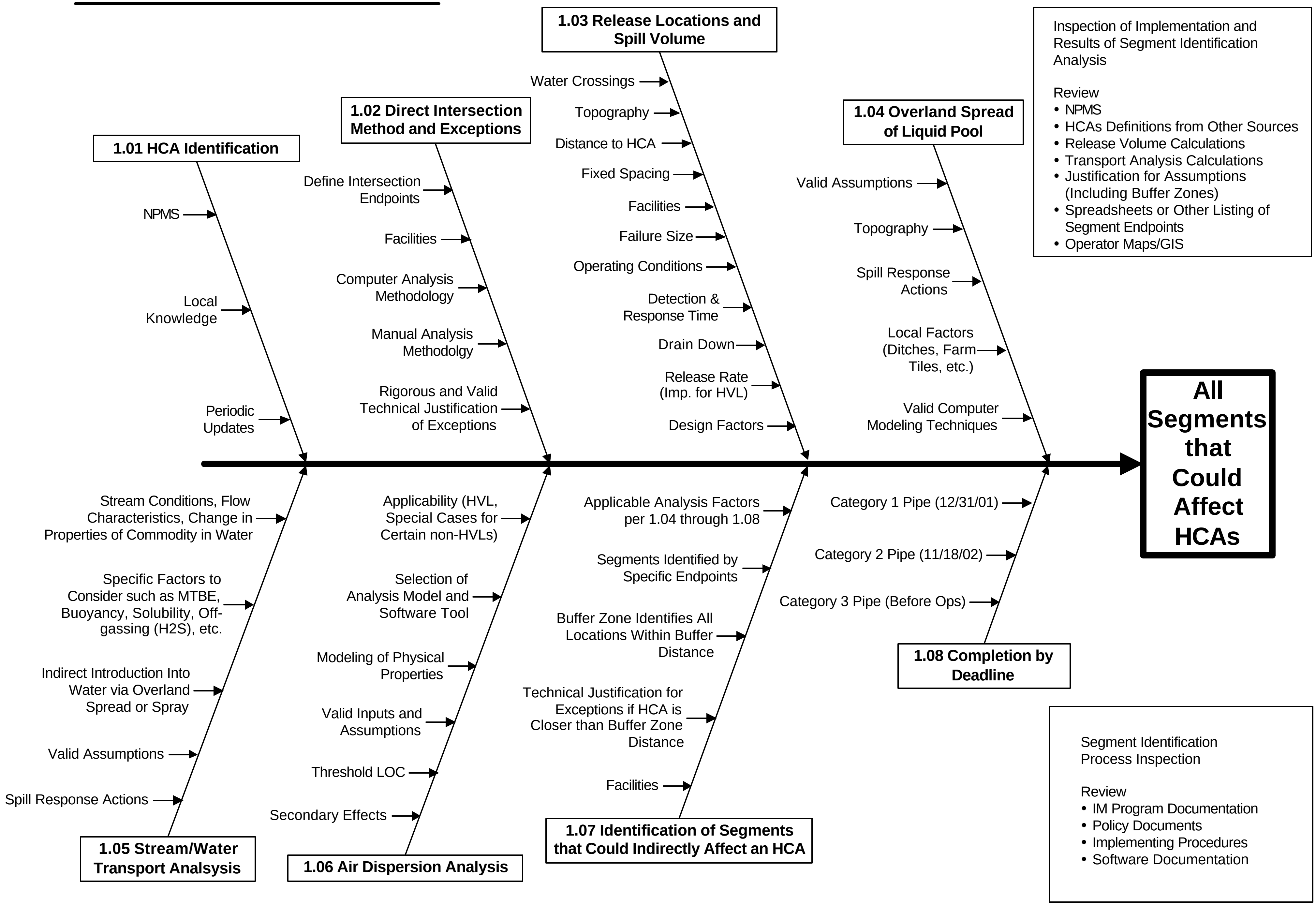
The operator must identify all segments that could affect HCAs by the prescribed dates:
1. 12/31/2001 for Category 1 pipelines
2. 11/18/2002 for Category 2 pipelines
3. Beginning of operation for Category 3 pipelines

A newly-identified HCA must be incorporated into the integrity management program within one year of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within five years of its identification.

Diagrams:
1. Protocol 1 Segment Identification Fishbone Diagram

Records:
1. Latest Edition of Integrity Management Inspection Protocols.

Segment Identification Additional Guidance Overview



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Element 2
Baseline Assessment Plan

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Section 2.1 Introduction

This element 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 element addresses the selection of assessment methods and the development of an integrated, risk-based prioritized assessment schedule.

The operator will perform baseline assessments by using one or more of the following acceptable integrity assessment methods.

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

  If ILI tools are used, they must be capable of detecting corrosion and deformation anomalies including dents, gouges and grooves. The operator will consider different types of internal inspection tools for the integrity assessment from the following list. Normally, a magnetic flux leakage (MFL) metal loss tool will be run first. If dents, gouges, or grooves are detected, then a geometry/deformation tool or physical inspection will be employed to inspect for all dents, gouges, and grooves. MFL tools can detect the presence of dents, but not reliably size them. Thus, PHMSA Pipeline Safety considers that any indication of a dent found using an MFL tool is potentially a defect meeting the repair criteria in the rule, until the contrary is demonstrated. PHMSA Pipeline Safety will accept an assessment conducted using an MFL tool without a concurrent deformation tool run if the operator specifically directs its ILI vendor to identify all potential dents. All such potential dents must then be excavated and examined, and those meeting rule repair criteria must be remediated. If all potential dents are not excavated, then a subsequent assessment using a deformation tool or hydrostatic test must be conducted on an expedited basis.

  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.

  Inline inspection tools are only available in certain sizes and some line segments cannot accommodate them. In those cases, alternate inspection techniques will be implemented. The type of tool or tools the Operator selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

  - Geometry Internal Inspection Tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;
  - Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion. Note, the anomalies interaction

rule will be discussed and agreed upon with ILI vendor and documented in the operator smart pig report.

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

API Standard #1160, Managing System Integrity for Hazardous Liquid Pipeline, will be used to assist in the determination of the proper inspection tool. See API #1160 guidance, see Table 9-1, Anomaly Types and Tools to Detect Them. Periodically, the operator will perform excavations to verify the accuracy and reliability of the inspection tools. Accuracy and reliability is specific to each tool type and manufacturer.

- Pressure test conducted in accordance with 195 subpart E;

  Except as otherwise provided in 49 CFR 195 subpart E (195.300-310), no new segment of pipeline or a segment of pipeline that has been relocated or replaced can be operated until it has been pressure tested without leakage. If a leak or pressure discontinuity is found, it must be investigated to determine its cause. All testing is in accordance with the 49 CFR subpart E and the operator O&M Manual, procedure #15.01.

  Pressure testing can be used as the primary assessment method in place of internal inspections. Hydrostatic testing is a valuable tool to destructively remove critical defects. Not all anomalies will be removed during a test; only those defects that reach a critical size will be removed during a test. Testing a pipeline segment above the operating pressure will demonstrate the absence of defects that could result in failure up to the test pressure.

  Hydrostatic testing is not as valuable when used to identify corrosion, particularly localized corrosion. Therefore, when the operator selects pressure testing as the assessment method, the following additional data gathered in conjunction with other inspections and tests will be reviewed in addition to the pressure testing:

  - Surveillance and patrols

  - Corrosion control monitoring and cathodic protection surveys

- External corrosion direct assessment 195.588 or

- Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe.

The operators must complete baseline assessments as follows:

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.

For prior assessments 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 the assessment outlined above. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to 195.452(j)(3) (5-year interval not to exceed 68 months). The table follows:

Pipeline	**Date**
Category 1	January 1, 1996.
Category 2	February 15, 1997.

Section 2.2 Assessment Methods (Protocol 2.01)

The operator's assessment method selection process will include the following:

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.

InformationResourceManager@dot.gov, or

Sending the notification by mail to ATTN:

Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave SE., Washington, DC 20590.

Section 2.3 Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Pre-Assessment (Protocol 7.05)

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.

Section 2.4 Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Indirect Inspection (Protocol 7.06)

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.

Section 2.5 Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Direct Examination (Protocol 7.07)

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.

Section 2.6 Prioritized Assessment Schedule (Protocol 2.02)

The operator will develop a prioritized schedule for assessment of pipeline segments. The operator's Baseline Assessment Plan will include the following:

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):
   a. Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
   b. Pipe size, material, manufacturing information, coating type and condition, and seam type;
   c. Leak history, repair history and cathodic protection history;
   d. Product transported;
   e. Operating stress level;
   f. Existing or projected activities in the area;
   g. Local environmental factors that could affect the pipeline (*e.g.,* corrosivity of soil, subsidence, climatic);
   h. Geotechnical hazards; and
   i. Physical support of the segment such as by a cable suspension bridge.
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.

The operators schedule will exhibit the following:

1. The schedule should 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.

The operator Baseline Assessment Plan implementation should include:

1. Assessments scheduled 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 the most recent Form PHMSA F 7000-1.1 appear valid and completed per Instructions for Completing Form PHMSA F 7000-1.1.

Section 2.7 Prior Assessments (Protocol 2.03)

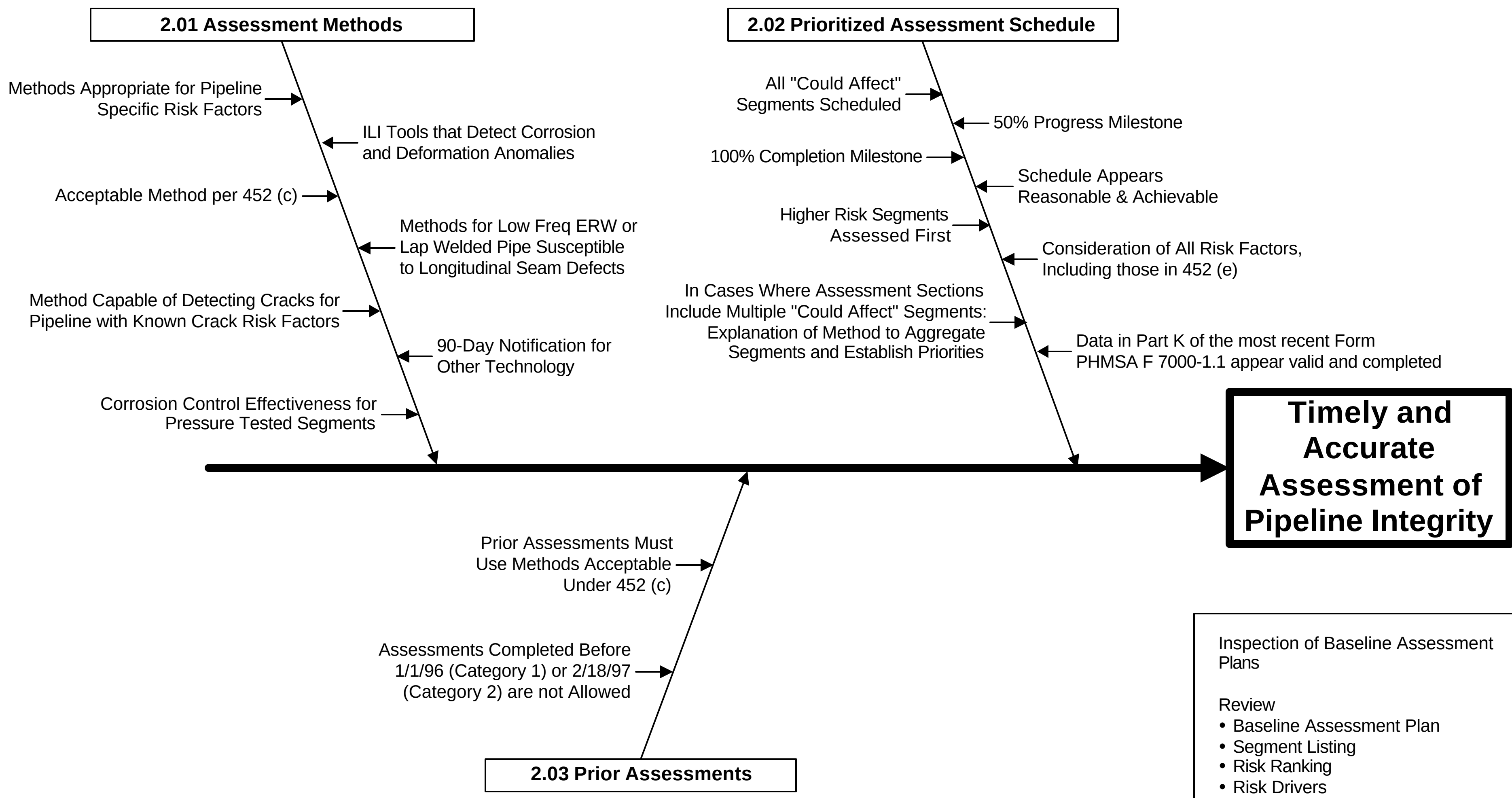
Assessments performed prior to the effective date of the rule may be used as baseline assessments provided they are consistent with rule requirements for baseline assessments. The operators Baseline Assessment Plan will include the following:

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.

Diagrams:
1. Protocol 2 Baseline Assessment Plan Fishbone Diagram
2. Protocol 7 Continual Process of Evaluation and Assessment Fishbone Diagram

Records:
1. Latest Edition of Integrity Management Inspection Protocols.

Baseline Assessment Plan
Additional Guidance Overview



Inspection of Baseline Assessment Plans

Review
- Baseline Assessment Plan
- Segment Listing
- Risk Ranking
- Risk Drivers
- Capabilities of Tools Selected
- Justification for Assessment Method Selection
- Schedule Details
- Completion Progress
- Baseline Assessment Plan Revisions

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Element 3
Integrity Assessment Results Review

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Section 3.1 Introduction

This element addresses the review, validation, and evaluation of results from integrity assessments (i.e., inline inspection, pressure testing, or other technologies). This element 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.

Section 3.2 Qualifications of Individuals that Review and Evaluate Assessment Results (Protocol 3.01)

Individuals who review assessment results and information analysis must be qualified to do so. This program requires that appropriate means be taken to ensure the requisite level of qualification, and will contain the following:

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.

Additional Guidance:

The purpose of this procedure is to establish the process for ensuring that data gathered through periodic evaluation of pipelines in accordance with the Integrity Management Program is analyzed by personnel qualified to determine the integrity of the pipe from the data. Inspections conducted under the operator's Integrity Management Plan will result in data that must be analyzed by personnel qualified to do so. In-line inspection data requires highly-specialized expertise and the benefit of experience to interpret the often cryptic analog indications provided by the tool. Hydrostatic pressure testing requires compliance with 49 CFR, Part 195, Subpart E, to be valid and requires expertise in compensating for varying factors such as temperature and elevation.

In-Line Inspection

Due to the extensive training and experience required to adequately interpret analog in-line inspection data, the operator will rely on its ILI vendors to provide the expertise required for data analysis. The operator will only contract with reputable in-line inspection vendors with at least three years of proven experience in inspecting and evaluating pipe using the tools for which they are being contracted. Specifically, the ILI vendor responsible for interpreting smart pig data will have the following qualifications:

- Three years of experience with tools used for the inspection

- The personnel operating the ILI systems and the personnel taking, reducing, analyzing and reporting the resultant data shall be qualified in accordance with API #1163 and ASNT ILI-PQ, level II.

The operator may conduct its own review of the data and the interpretations provided by the vendor as a quality control check. The person conducting such QC reviews should have had at least one year of experience in reviewing ILI raw data, but in no case shall the reviewer over-ride the interpretations of the vendor unless it results in a more conservative response to the data. In all cases, questions regarding a vendor's interpretation shall be referred back to the vendor for review and clarification.

All reviews of inline inspection reports shall include any conclusions, identification of any integrity issues and any potential trends. Assessment results conclusions will be retained for the life of the pipeline. Assessment results will only be distributed to the appropriate IMP Team members and management.

The engineer reviewing the inline inspection report shall request feedback from the vendor in regards to the tool performance and results. This report shall be maintained as part of the IMP records.

Direct Assessment

Procedures for direct assessment will be developed before use. If using third party for completion of direct assessment the operator will review and approve vendor procedures before use.

Section 3.3 ILI Vendor Specifications (Protocol 3.02)

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. The operator will demonstrate that the ILI vendor has met all the requirements. 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.]

Section 3.4 ILI Validation of Assessment Results (Protocol 3.03)

After ILI tool runs are completed, the operator will 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. The operator would complete the following:

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.

Additional Guidance:

After ILI tools are run, the operator will perform excavations or use other techniques to verify the accuracy and reliability of the inspection tools in order to have confidence in the assessment results. Verification of tool tolerance shall be one piece of information that should be verified. Tool tolerance is specific to each tool type and manufacturer.

Information on tool tolerances should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized. This does not necessarily mean simply adding the vendor-supplied tolerance value to reported depth of indications. Several sources of data may be used, in conjunction with vendor-supplied tool tolerances, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data should also be considered.

In addition, information on tool tolerances may be incorporated in engineering analysis such as "probability of exceedance" to help operators prepare a comprehensive defect remediation plan and schedule future assessments. The operator will have the flexibility to apply processes specific to their unique risks by utilizing these techniques when evaluating specific pipeline defects.

Tool tolerances are not the only uncertainty associated with assessment results, and are therefore not the only factor to be considered in evaluating the quality of internal inspection data and in making excavation timing and mitigation decisions. Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in §195.452(h)(4), are promptly identified.

The primary method the operator will use to validate and calibrate ILI tool data will be through excavations. The IMP Leader and/or IMP Team will make the determination on the appropriate number and location of validation digs. The operator will use a <u>minimum of two excavation digs</u> unless the IMP Leader and IMP Engineer can justify a lesser number. If data comparison from the two excavations conflicts with the ILI tool anomaly data, a least one other excavation dig shall be performed. The operator will select the two most severe locations for the two validation digs, unless the engineer can justify otherwise. The engineer shall document their excavation decision based on statistics or other sound engineering practices.

The actual anomaly characteristics (type and dimensions) will be compared to the anomaly characteristics inferred from the ILI tool data to calibrate the ILI tool data to match known examples of detected anomalies. The operator will work with the ILI vendor to assure the assessment data is valid.

The engineer shall prescribe the required information to be gathered during an excavation to ensure proper validation of the inline inspection tools. These verifications will be selected to verify tool accuracy for various types of anomalies, including but not limited to, internal corrosion, external corrosion, dents, ovality, gouges, and other types of anomalies. In the case of metal loss anomalies, an onsite UT tool will be used to determine the actual remaining wall thickness in order to verify or eliminate the possibility of internal corrosion.

Section 3.5 Integration of Other Information with Assessment Results (Protocol 3.04)

The operators will 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. The operator will conduct the following:

1. 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. Provide data that has been collected and disseminate to persons evaluating assessment results.
3. Provide for integrations the following types of information, as appropriate:
    a. Previous assessment results;
    b. Surveillance, testing, and other monitoring data (e.g., internal corrosion coupon monitoring);
    c. Historical maintenance and repair information;
    d. Uncertainty of assessment results including tool tolerances;
    e. Any other information related to pipeline integrity; and
    f. 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. Document 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. Identify and document integrity issues and potential trends in the integrity of the pipeline.

Section 3.6 Integration of Other Information with Assessment Results (Protocol 3.05)

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. The operator will conduct the following:

1. Ensure that all repair conditions are discovered within 180 days of completion of the assessment.
2. 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. Define the time at which the discovery of an anomaly occurs.
4. 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.)

Additional Guidance:

<u>Discovery of a condition</u> occurs when the operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, the operator may have adequate information when it receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, or when it receives the final internal inspection report. The operator is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is not feasible. The integrity assessment will be complete when the internal inspection tool is removed from the pig trap.

The engineering staff will <u>analyze</u> the integrity assessment final report and categorize reported anomaly conditions per the evaluation and repair schedule in this IMP program. If the operator will not be able to meet the schedule, a record will be placed in the IMP file by the engineering staff explaining why the schedule cannot be met and stating that the changed schedule will not jeopardize public safety and/or environmental protection. The conclusion of the assessment review shall be documented by the engineer. The summary report shall include any conclusions, identification of any integrity issues, potential trends, and other appropriate integrity issues.

195.452 requires the operator to notify OPS if they are unable to meet the repair schedules and cannot provide safety through a temporary reduction in operating pressure. Such notifications should explain the reasons why the repairs cannot be made, describe actions being taken to resolve the issues precluding repair work, and indicate when these issues are likely to be resolved. The operator will attempt to submit notifications as early as possible, to allow time for OPS review.

The notification will be sent to the following address:

- Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

- Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd floor, E22321, 1200 New Jersey Ave SE., Washington, DC 20590.

Section 3.7 Hydrostatic Pressure Testing (Protocol 3.06)

The operator will complete the following for Hydrostatic Pressure Testing:

1. Test records will be compliant with Part 195 Subpart E requirements.
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.

Additional Information

Hydrostatic testing shall be performed in compliance with 49 CFR, Part 195, Subpart E. The hydrotest will be conducted under the direction of an operator employee who has been qualified to the operator's Operator Qualification Program. A operator engineer, consulting engineer, or certified testing operator shall certify the hydrostatic test.

Section 3.8 Results from the Application of Other Technologies (Protocol 3.07)

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. The operator program would demonstrate 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.]

Additional Guidance:

If the operator decides to perform assessments using other technology, the operator will develop IMP procedures for selection of technology, review of industry standards, validation of other technology results, and procedures that address reporting and analysis of anomalies and defects.

Diagrams:

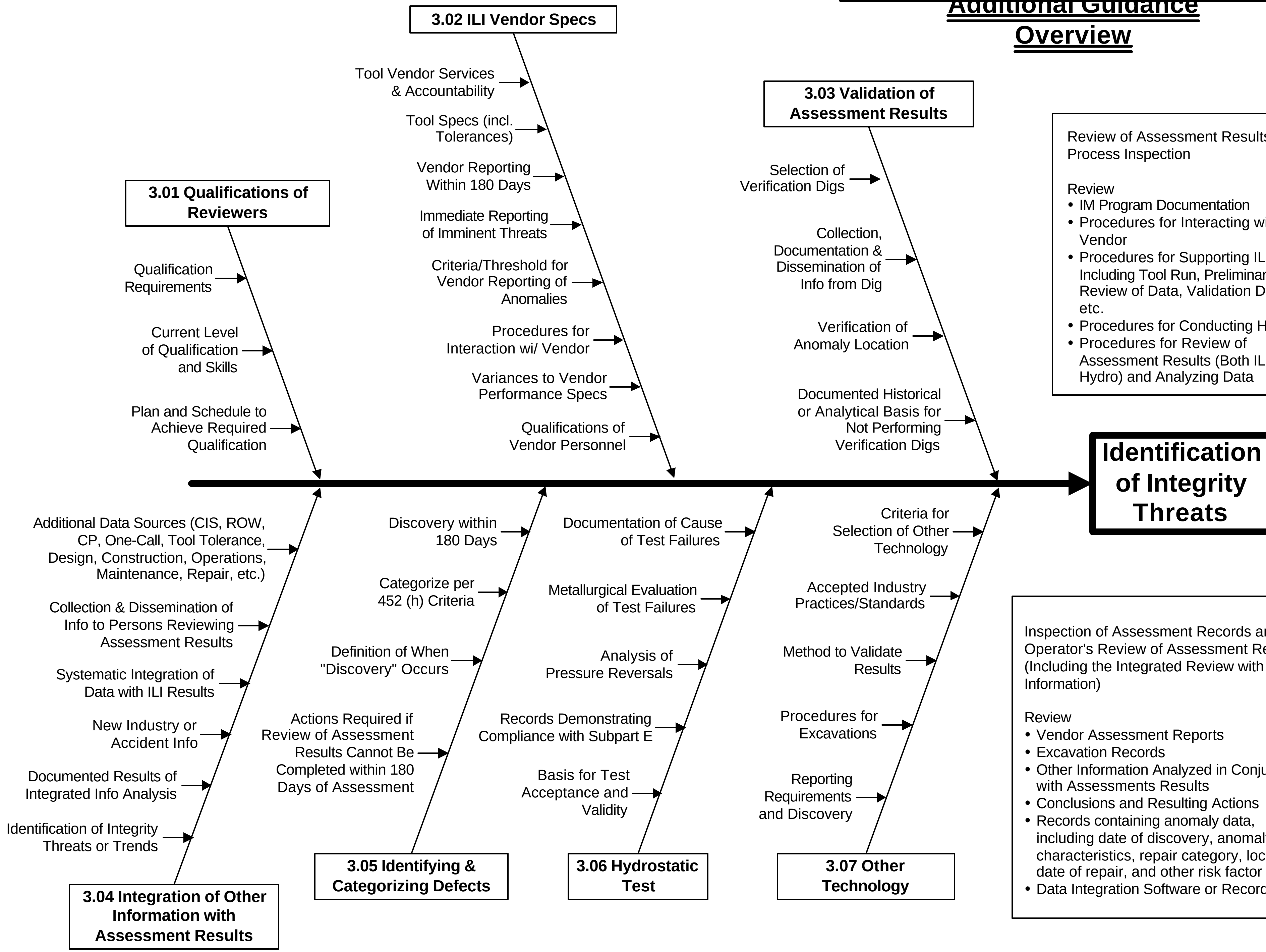
1. Protocol 3 Integrity Assessment Results Review Plan Fishbone Diagram

Records:

1. Latest Edition of Integrity Management Inspection Protocols.

Integrity Assessment Results Review Additional Guidance

Overview



Review of Assessment Results Process Inspection

Review
- IM Program Documentation
- Procedures for Interacting with Vendor
- Procedures for Supporting ILI Including Tool Run, Preliminary Review of Data, Validation Digs, etc.
- Procedures for Conducting Hydros
- Procedures for Review of Assessment Results (Both ILI and Hydro) and Analyzing Data

Inspection of Assessment Records and the Operator's Review of Assessment Records (Including the Integrated Review with Other Information)

Review
- Vendor Assessment Reports
- Excavation Records
- Other Information Analyzed in Conjunction with Assessments Results
- Conclusions and Resulting Actions
- Records containing anomaly data, including date of discovery, anomaly type, characteristics, repair category, location, date of repair, and other risk factor data.
- Data Integration Software or Records/GIS

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Element 4
Remedial Action

Table of Contents

Section 4.1 Introduction

This element 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.

Section 4.2 Process (Protocol 4.01)

The operator will take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. The operator will complete following :

1. 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. Document justification for changes to the repair/remediation schedule including demonstration that such changes will not jeopardize public safety or environmental protection.
3. 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. 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. Temporary reduction in operating pressure until repair or remediation can be completed. The pressure reduction 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. The operator comply with §195.422 when making a repair.
7. Specification of the records to be generated during the remediation process.

Additional Guidance:

Schedules for Evaluation and Remediation

Data from integrity assessments will be evaluated and a schedule of field evaluation and remediation that is prioritized according to the severity of the reported anomalies described in the assessment final report will be developed. Anomaly conditions for evaluation and remediation will be prioritized as follows:

1. Immediate Repair Conditions
2. 60-day Conditions

3. 180-day Conditions
4. Other Conditions

Immediate Repair Conditions: Conditions which must be treated as immediate repair conditions are given in § 195.452 (h)(4)(A-E) and listed below.

- metal loss greater than 80 percent of nominal wall thickness
- calculated burst pressure less than maximum operating pressure (MOP) at an anomaly
- top dent with any indication of metal loss, cracking, or stress riser
- top dent (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter
- Any anomaly judged to require immediate attention

To maintain safety, the operating pressure will be temporarily reduced or the pipeline will be shut down until the repair of these conditions is completed**.** The temporary reduction in operating pressure shall be calculated using the ASME/ ANSI B31G and PRCI-3-805 (R-STRNG). If no suitable remaining strength calculation method can be identified, an operator must implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two months prior to the date of inspection, until the anomaly is repaired.

The method described in ASME/ ANSI B31G and PRCI-3-805 (R-STRNG) is required by the rule and must be used for all circumstances for which it is appropriate (e.g., corrosion). When the method is applied based on in-service inspection log results, the tolerance of the inspection tool must be taken into consideration. That is, if the tool has a tolerance of plus or minus 10 percent, a best- estimate indication of 40 percent wall loss must be increased to 50 percent for use in the formula of section 451.7.

There are anomalies defined by the rule as immediate repair conditions for which the method of section 451.7 is not applicable (e.g., dents). The calculation in Section 451.7 of ASME/ANSI B31.4 is applicable to determining the remaining strength of pipe with corrosion defects or grind repairs (i.e., loss of wall thickness).

Pressure must be reduced for other types of immediate repair conditions, but the operator must develop appropriate engineering justification for the amount of pressure reduction. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the "maximum operating pressure" for the pipe. For example, a reduction of 20 percent below the highest operating pressure experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin.

Paragraph 195.452(h)(1)(ii) limits any reduction in operating pressure to no more than 365 days before an operator must take further remedial action to ensure the safety of the pipeline.

60 day condition: A defect or anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 60 days of discovery. The rule identifies the following as 60-day conditions.

- A dent located on top of the pipeline (above 4 and 8 o'clock positions) with a depth greater than 3 percent of the pipeline diameter (greater than 0.25 inches for a pipeline diameter less than NPS 12)
- A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or stress riser (NOTE: Top-of-the-pipe dents with metal loss, cracking or stress riser are an immediate repair condition)

180 day condition: A defect of anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 180 days of discovery. The rule identifies the following as 180 conditions. A dent with depth greater than 2% of the pipeline's diameter (0.25 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld

- A dent located on the top of the pipeline (between the 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.25inches in depth for a pipeline diameter less than NPS 12)
- A dent located on the bottom of the pipeline with a depth greater than 6 % of the pipeline's diameter
- A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly (using suitable calculatingly methods)
- An area of general corrosion with a predicted metal loss greater than 50% of nominal wall
- Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
- A potential crack indication that when excavated is determined to be a crack
- Corrosion of or along a longitudinal seam weld
- A gouge or groove greater than 12.5% of nominal wall

Other Conditions

The following are some examples of conditions that an operator should schedule for evaluation and possible remediation.

- Significant changes since the previous assessment
- Mechanical damage located on top of the pipe
- An anomaly with abrupt features that could act as a stress concentrator
- An anomaly longitudinal in nature
- An anomaly over a large area

- An anomaly located in or near a casing, foreign pipeline crossing, or area subject to CP interference

[FAQ.7.7] Are there other anomalies that an operator is required to address?

Yes. All conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. Part 195 Appendix C contains guidance concerning other conditions that an operator should evaluate.

Evaluation and Remediation Schedule Cannot be Met

The operator will complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If the operator cannot meet the schedule for any condition, the operator will 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)(3)]

The engineering staff will analyze the integrity assessment final report and categorize reported anomaly conditions per the evaluation and repair schedule in this IMP program. If the operator will not be able to meet the schedule for any condition category, this will be documented by the engineering staff explaining why the schedule cannot be met and stating that the changed schedule will not jeopardize public safety and/or environmental protection.

195.452 (h) (1) requires the operator to 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 the operator taking further remedial action to ensure the safety of the pipeline. The operator will comply with § 195.422 when making a repair.

Temporary pressure reduction [195.452(h)(1)(i)]

The operator must notify PHMSA, in accordance with 195.452(m), if the operator cannot meet the schedule for evaluation and remediation required under 195.452 (h) (3) and cannot provide safety through a temporary reduction in operating pressure.

The operator will attempt to submit notifications as early as possible, to allow time for OPS review. The notification will be sent using the PHMSA online submittal process.
Web address for submittal is shown below:

InformationResourceManager@dot.gov, or

Sending the notification by mail to ATTN:

Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave SE., Washington, DC 20590.

Long-term pressure reduction [195.452(h)(1)(ii)]

When a pressure reduction exceeds 365 days, the operator must notify PHMSA and explain the reasons for the delay. The operator must also take further remedial action to ensure the safety of the pipeline.

Repair and Remediation Methods

All repairs will be made in accordance with 195.422 and the operator O&M Manual. API #1160, Managing System Integrity for Hazardous Liquid Pipelines will be used as a guide to assist in determination of the type of repair/remediation that will be employed. See table 9-2, Summary of Commonly Used Permanent Pipeline Repairs. Repair records include:

- Operator Qualifications
- O&M procedure used
- Repair method
- What condition was repaired
- Pressure test
- Decision process for the repair

When the repair is a result of the integrity management regulations and this IM program, the data will be used as input on PHMSA Form F 7000-1.1.

Section 4.3 Implementation (Protocol 4.02)

The operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. The 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 operator shall keep the following records:

1. A prioritized schedule 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.

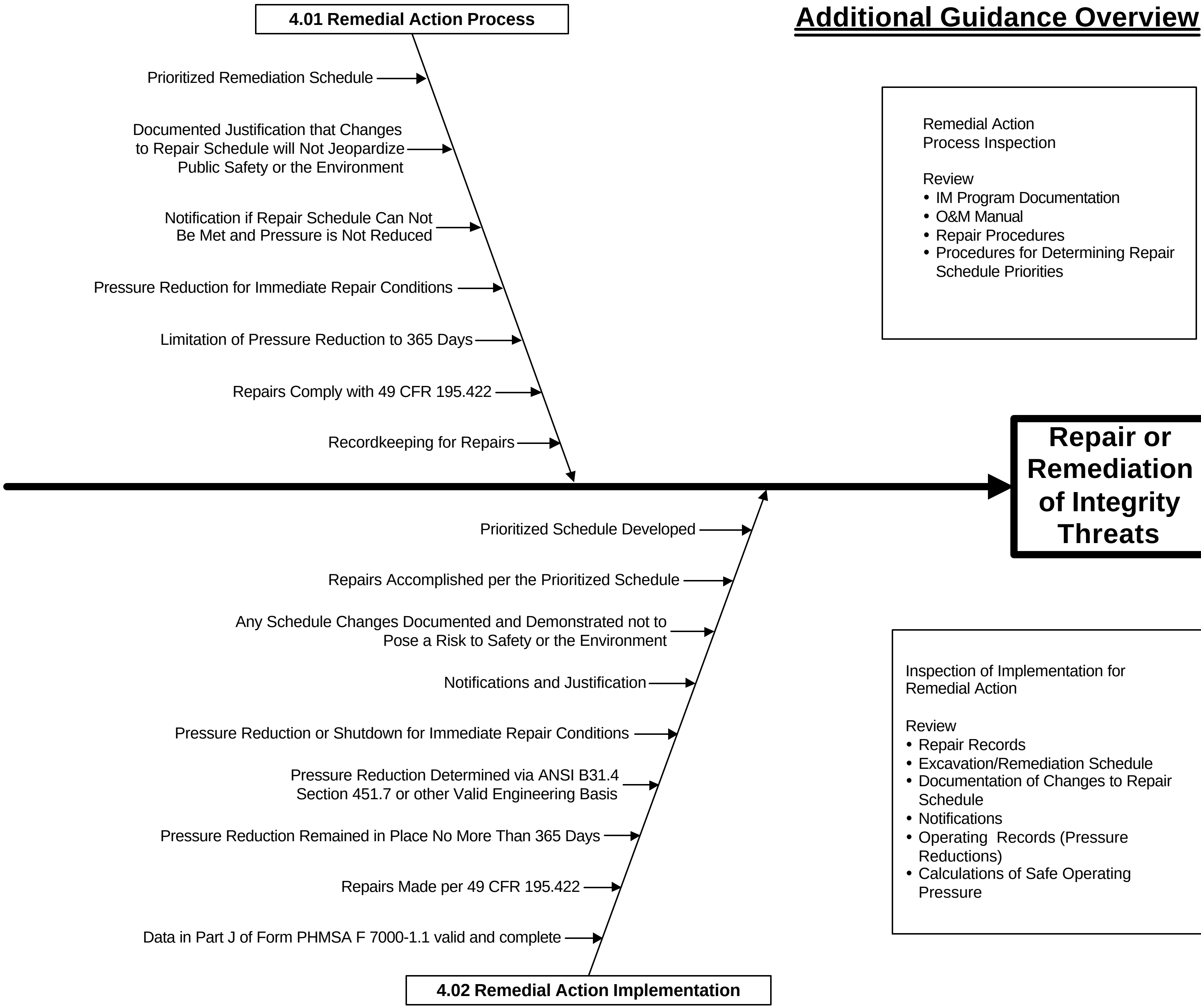
Diagrams:

1. Protocol 4 Remedial Action Fishbone Diagram

Records:

1. Latest Edition of Integrity Management Inspection Protocols.

Remedial Action Additional Guidance Overview



Remedial Action
Process Inspection

Review
- IM Program Documentation
- O&M Manual
- Repair Procedures
- Procedures for Determining Repair Schedule Priorities

Inspection of Implementation for
Remedial Action

Review
- Repair Records
- Excavation/Remediation Schedule
- Documentation of Changes to Repair Schedule
- Notifications
- Operating Records (Pressure Reductions)
- Calculations of Safe Operating Pressure

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Element 5 & 8
Continuing Assessment and Risk Analysis & Review of Integrity Assessment Results and Data Analysis

Table of Contents

Section 5.1 Introduction

This element addresses the overall risk analysis/information analysis process employed by the operator 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 element 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.

This element also covers the requirements for conducting periodic integrity assessments based on the results of operator evaluations of pipeline integrity. This element 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.

Section 5.2 Comprehensiveness Approach (Protocol 5.01)

The operator's process for evaluating risk includes the following categories of risk factors:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
    a. external and internal corrosion
    b. stress corrosion cracking
    c. materials problems
    d. third party damage
    e. operator or procedures errors
    f. equipment failures
    g. natural forces damage
    h. construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
    a. health and safety impact
    b. environmental damage
    c. 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.).

Additional Guidance:

Minimum Risk Factors for Establishing Frequency of Assessment -

The operator will use the following list of risk factors for establishing frequency of assessment.

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

2. Results from previous assessments, testing/inspection. [195.452(h)]
3. Leak history.
4. Known corrosion or condition of pipeline. [195.452(g)]
5. Cathodic protection history.
6. Type and quality of pipe coating (disbonded coating results in corrosion).
7. Age of pipe (older pipe shows more corrosion–may be uncoated or have an ineffective coating) and type of pipe seam.
8. Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment).
9. Pipe wall thickness (thicker walls give a better safety margin)
10. Size of pipe (higher volume release if the pipe ruptures).
11. Local environmental factors that could affect the pipeline
    a. Geo-technical = seismic faults, landslides, subsidence, and soil condition
    b. Climatic = permafrost, et
    c. Corrosivity of soil
12. Security of throughput (effects on customers if there is failure requiring shutdown).
13. Time since the last internal inspection/pressure testing.
14. Previously discovered defects/anomalies, including type, growth rate, and size.
15. Operating stress levels in the pipeline.
16. Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).
17. Physical support of the segment such as by a cable suspension bridge.
18. Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).
19. Other regulatory interval requirements
20. Construction activity in the area.
21. General health and safety factors (employees and public)
22. Environmental impacts
23. Property damage
24. Local economic impact
25. Other segment specific factors as determined by the Company

Other factors considered in the analysis will include information analysis, decisions about remediation, and preventive and mitigative actions. Risk is an inherent part of life and is associated with pipeline activities. While the overall risk of an operating pipeline can be managed, changed, or possibly reduced, it cannot be reduced to zero. Understanding risk factors is an important part of an IMP, because it is used to identify mitigation strategies. The total risk for a particular pipeline segment is the summation of the risks from the various threats to that segment.

Section 5.3 Integration of Risk Information (Protocol 5.02)

The operator will 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. The operator program will have the following:

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.

Section 5.4 Process for Input of Data and Information (Protocol 5.03)

The overall quality and usefulness of a risk analysis process is highly dependent on the validity and quality of input data and information. The operator’s risk analysis shall have the following:

1. Requires the use of the most accurate available data to represent pipeline characteristics in the analysis of different segments, including the results of integrity assessments.
2. Ensure the accuracy and completeness of information and data used in the identification of potential threats and the risk analysis.
3. Additional inspection activities or field data collection efforts as needed to ensure data completeness and accuracy.
4. Minimize the use of input information that is unnecessarily or excessively conservative (to avoid masking best-estimate risk insights).
5. Requires the use of sources best suited to provide whatever subjective information is used (e.g., from operator personnel, including field units).
6. Obtain subjective information (e.g., using forms, surveys, interviews, quality checks, etc.) to ensure that consistent information is provided for different segments.
7. Industry's collective operating experience data where applicable.
8. Address currently unknown or missing data in the risk analysis.
9. Requires the comparison of leak, failure, and incident measures to the operator’s risk model, and modifying the risk model if necessary to reflect system performance.

Section 5.5 Adequacy of Data and Input Information (Protocol 5.04)

The validity of the results of a risk analysis process is highly dependent on the validity and quality of data and information input into the risk analysis process. The operator will provide:

1. Records show the use of the most accurate available data to represent pipeline characteristics in the analysis of different segments.
2. Records show controls to provide assurance of the completeness and accuracy of input information were in accordance with the operator’s procedure.
3. Records show the use of sources best suited to provide whatever subjective information is used.
4. Records show that additional inspection or field data collection activities were performed to improve the accuracy and completeness of the data.
5. Records show the use of a sufficiently structured process for obtaining subjective information to ensure that consistent information is provided for different segments.
6. Records show the use of the operator's, and industry's, collective operating experience data where applicable?
7. Records show that local/field knowledge was used.
8. Records show that a plan to address missing or unknown data is being implemented.
9. Records show that the operator’s leak, failure, and incident measures have been compared to its risk model and the risk model modified as necessary to reflect system performance.

Section 5.6 Risk Analysis of Segments that could Affect HCA’s (Protocol 5.05)

The pipelines will be subdivided for the evaluation of risk. The operator will demonstrate:

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.

Section 5.7 Results (Protocol 5.06)

The operator risk results shall include the following:

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. Evaluating and reducing 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.]

Section 5.8 Facilities (Protocol 5.07)

In addition to line pipe, associated facilities that can affect HCAs should also be included in the IM Program. 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, the operator should include 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). The operator will provide the following:

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.

Section 5.9 Continual Process of Evaluation and Assessment: Periodic Evaluations (Protocol 7.01)

The operator will periodically evaluate pipeline integrity. The periodic evaluation should consider:

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.

Section 5.10 Continual Process of Evaluation and Assessment: Re-assessment Intervals (Protocol 7.02)

The operator will determine future integrity assessment plans based on the following:

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.

Section 5.11 Continual Process of Evaluation and Assessment: Re-assessment Intervals (Protocol 7.03)

The operator will select a tool that adequately assess the integrity of the pipeline. The operator's assessment method selection process should include:

1. 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. 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. 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. ii. Documentation that demonstrates the individual's qualifications and proficiency, and
        iii. 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.

The operator will also complete the following if applicable:
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.

Section 5.12 Continual Process of Evaluation and Assessment: Assessment Interval Variance (Protocol 7.04)

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 should address the following if applicable:

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.

The operator program will provide the following:

1. 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. Pro-actively identify and address issues that could adversely impact meeting assessment schedules.
4. Adequately document justifications for extending assessment intervals due to unavailable technology.

Additional Guidance:

Notification to PHMSA can be made by:

1. Sending the notification by electronic mail to InformationResourcesManager@dot.gov; or

2. Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22321, 1200 New Jersey Ave SE., Washington, DC 20590.

Section 5.13 Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Post-Assessment (Protocol 7.08)

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.
    c. Incorporation of feedback at all appropriate opportunities throughout the ECDA process to demonstrate continuous improvement.

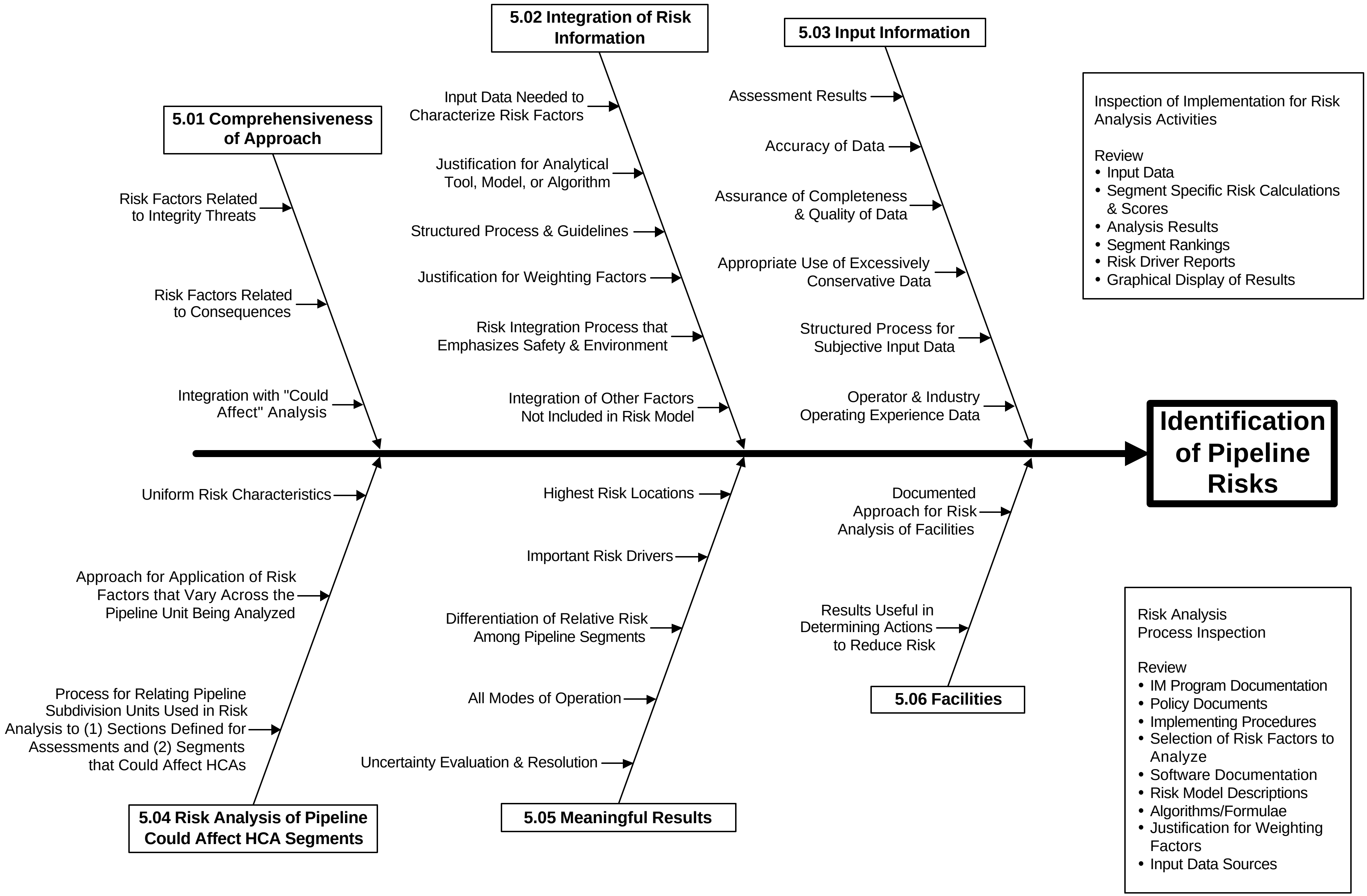
Diagrams:

1. Protocol 5 Risk Analysis Fishbone Diagram
2. Protocol 7 Continual Process of Evaluation and Assessment Fishbone Diagram.

Records:

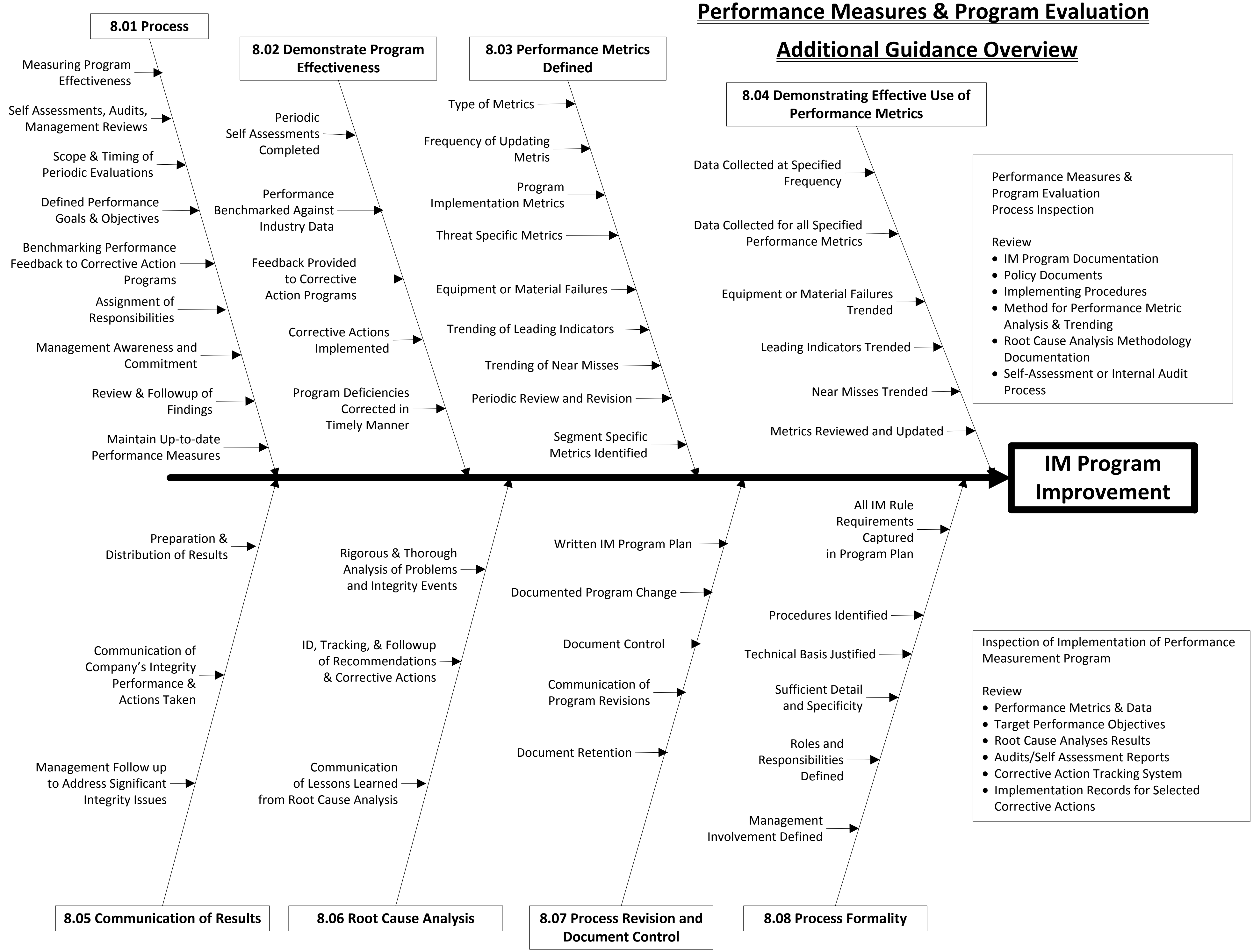
1. Latest Edition of Integrity Management Inspection Protocols.

Risk Analysis
Additional Guidance Overview



Performance Measures & Program Evaluation

Additional Guidance Overview



Hazardous Liquid Integrity Management Plan
(Rev July 2017)

Element 6
Preventative & Mitigative Measures

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Section 6.1 Introduction

The operator will take measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA. 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 CP where corrosion is a concern, establishing shorter inspection intervals, installing Emergency Flow Restricting Devices (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.

Section 6.2 Actions Considered (Protocol 6.01)

The operator will take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. The operator will complete the following:

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).

Additional Guidance:

The operator’s integrity management program includes applicable mitigation activities to prevent, detect, and minimize the consequences of unintended releases. Mitigation activities do not necessarily require justification through additional in-line inspection data. Mitigative actions can be identified during normal pipeline operation, during the initial risk assessment, during implementation of the baseline inspection plan, or during subsequent testing. Priority in schedule and scope for additional actions will be given to the highest risk lines and facilities.

The operator will consider a spectrum of modifications, ranging from incremental improvements to major changes. Changes to both documented work processes (e.g., procedures, response plans) and physical changes will be considered. Additional preventive and mitigative actions for non-pipe facilities (breakout tanks, pump stations, etc.) that can affect an HCA will also be considered.

The mitigation activities presented in this section include information on:

- Preventing TPD
- Controlling corrosion
- Detecting and minimizing the consequences of unintended releases
- Operating pressure reduction

Prevention of Third-Party Damage

TPD is a major cause of pipeline releases. Current US DOT data indicates that roughly one-quarter of all reported pipeline incidents are caused by TPD. The following mitigation activities will be considered.

- One Call Utility Locating Systems
- Improved Line Marking
- Optical Electronic Detection
- Increased Depth of Cover
- Improved Public Education (ID of excavators, emergency responders and public officials)
- Right-of-Way Maintenance
- More Frequent Right-of-Way Inspection
- Mechanical Pipe Protection
- Additional Pipe Wall thickness
- Pipeline Marker Tape Over Pipeline

One Call Utility Locating Systems

The operator is a member of the state “One Call” locating system. The operator will ensure that all pipelines in the system are included in this system. Designated personnel will be equipped and trained to accurately locate and mark the pipeline in response to each one call inquiry.

Improved Line Marking

Line marking is part of the first line of defense against third-party incidents. Additional markers make the pipeline more visible to third parties working in the vicinity. Line markers will generally be required on both sides of each road, highway, railroad, and water crossing. In areas of high third-party activity, intermediate line markers may be installed such that at least two markers are visible from any location along the line. Line markers in other areas will be spaced so that the line location is accurately known, where practical. Aerial line markers will also be utilized, where applicable, to provide marking for periodic aerial right-of-way inspections.

Surface line markers will be labeled with the pipeline operator's 24-hour emergency telephone number and information required by 195.410. Refer to the operator pipeline O&M manual for details.

Optical or Ground Intrusion Electronic Detection

These systems include a fiber optic or metallic cable, usually installed twelve to twenty-four inches above the pipeline that are continuously monitored by optical or metallic instruments. Should the cable become damaged or severed, the monitoring device(s), which are integrated into the pipeline programmable logic controllers (PLCs) and supervisory control and data acquisition (SCADA) system, issue an alarm and identify the location of the cable damage.

Optical or electronic ground intrusion detection systems, may reduce the consequences of third-party intrusion in three ways:

Damage prevention- The system may reduce the frequency of third-party incidents by alerting the operator of the location of potential third-party intrusions before the pipeline is damaged.

Prevention of unintended releases- A system alarm may reduce the likelihood of a leak in the event the pipeline is damaged, but not ruptured by third parties. This allows the operator to respond and perform an immediate inspection and/or repair, at the location the damage occurred.

Spill minimization- In the event third-party intrusion results in an immediate rupture, the intrusion alarm, coupled with a release alarm, will allow response to occur more quickly, and potentially reducing the volume released significantly.

Increased Depth of Cover

Increasing the pipeline depth of cover (e.g., five or six feet below ground surface) may place the pipe below many normal excavation and agricultural activities, thereby reducing the chance of third-party intrusions. This is also an important consideration at stream and other crossings. For example, the depth or scour will be evaluated at major stream crossings. The pipeline will then be buried well beneath the potential scour depth of active streams. When increased depth of burial or increased cover is desired yet not practical, mitigation options include concrete caps, increased line marking, electronic warning tapes as well as plastic tape and mesh marking above the line or fencing off areas particularly susceptible to TPD.

Note: Excessive depth of burial can be detrimental to pipeline operation and safety. Locations of unintended releases can be difficult to isolate, excavations can be more hazardous, lines are more difficult to locate and repairs can become more complex.

Improved Public Education

The operator currently implements educational and public awareness programs designed to also meet requirements of current federal regulations. These programs educate the public, emergency responders, and persons engaged in excavation related activities as to the whereabouts, potential dangers, and appropriate emergency responses associated with the pipeline facilities. These programs can help reduce a pipeline operator's exposure to TPD and enhance emergency response in the event of an incident. The operator will consider improving public education beyond the minimum regulatory requirements to reduce third-party exposure where such risks are high. API #1162 – Damage Prevention for Hazardous Liquid Pipelines will be used as a guide in development of the operator's damage prevention procedures.

Right-of-Way Maintenance

Having a plan to protect pipelines and rights-of-ways will reduce the chance of TPD and enhance the ability for response to an emergency. Consideration will be given to developing guidelines addressing the following maintenance issues which would reduce the consequence of third-party intrusion. Refer to the operator pipeline O&M manual for details.

- Control of vegetation in the right-of-way
- Removal of trash, brush, and other items near the pipeline
- Control of impediments constructed above or below ground near the pipeline (including, but not limited to, buildings, engineered structures, pavement, pools, fences, etc.).
- Operation of heavy equipment over pipeline
- Blasting near the pipeline
- Crossing the pipeline
- Excavation or boring near the pipeline

Improved or More Frequent Right-of-Way Inspections

Current federal pipeline regulations require regular right-of-way inspections and maintenance. These regular inspections enable the operator to identify activities that may encroach upon their right-or-way before the pipeline facility can be impacted. The operator will consider more frequent inspections, or take other actions to make the pipeline more visible, in areas subject to a high level of third-party activities

Mechanical Pipe Protection

Mechanical protection, designed to shield a pipeline from TPD, may be accomplished in two ways. This would normally only be considered for new pipeline systems.

First, a segment of pipeline can be coated with reinforced concrete, installed over the top of the external corrosion coating. The external concrete coating can be installed at most coating plants and is intended to provide mechanical protection from excavation equipment, or from gouges and punctures from other external forces.

Caution: Concrete in contract with the steel pipe may change the pH and cause an increase in corrosion of the pipe surface.

Alternately, a concrete cap can be installed above the pipeline to provide a physical barrier to excavation and other equipment digging above a pipeline. Selection of this approach needs to carefully consider the areas of high risk, along with other factors such as reducing access for ordinary repairs, etc. It is important that the concrete cap not contact the pipeline.

Additional Pipe Wall Thickness

Additional pipe wall thickness may increase the resistance of a pipeline to TPD. This option is normally only a consideration during the initial construction of a pipeline. The additional pipe wall thickness may provide mechanical protection against a puncture and allow the pipe to be gouged, with less chance of immediate leakage. The lower stress that results with a thicker wall also makes the pipe less prone to rupture.

Pipeline Marker Tape or Warning Mesh Installed Over Pipeline

Marker tape or warning mesh installed above a pipeline is an additional measure to protect against TPD. This option is generally implemented during installation of the pipeline. The brightly colored tape or plastic mesh will typically be installed approximately one or two feet above the pipeline and appropriately labeled (e.g., hazardous liquid pipeline/operator name).

Monitor and Maintain Cathodic Protection

Pipe coating systems, combined with cathodic protection, provide effective corrosion control of the external pipeline surfaces. Pipeline cathodic protection will be installed, monitored, and maintained in compliance with federal requirements and NACE International (National Association of Corrosion Engineers) Recommended Practice RP-01-69. Cathodic protection system data will be integrated with in-line inspection data and other information as described in this IMP Program.

Additional monitoring of cathodic protection systems utilizing close interval potential surveys and/or coating integrity surveys will be considered. Risk assessment, in-line inspection data, results of routine system monitoring, open hole inspections and release history are factors which may indicate that a close interval potential survey is needed.

External pipe coating systems will be evaluated, monitored, and maintained. Control of corrosion is highly dependent on the integrity of the external coating system.

Detecting and Minimizing Unintended Pipeline Releases

In the event of an unintended product release from within a pipeline system, the consequences can be minimized by considering the following prevention and mitigative measures:

- Reducing the time required for detection of the release
- Reducing the volume that can be released
- Reducing the time required to locate the release
- Reducing emergency response time

Reducing Detection Time and Volume Lost From Unintentional Releases

The role of release detection is to minimize the time required to detect product that is actively being released from a pipeline system. It is important to evaluate and understand the potential volume of pipeline product that might be released prior to an alarm event from a release detection system. Release detection technology and equipment provide a wide range of sensitivity and reliability

Release detection system manufactures, and/or manufacturer's representatives, will provide the operator with written descriptions of system capabilities and performance expectations for each specific pipeline segment application. The performance expectations will be described in terms of product volume released versus time for detection. Potential release detection system limitations, or concerns for specific service suitability, will also be provided to the operator.

The performance and reliability of the communications system(s) may significantly affect the performance and response times of some release detection systems. The operator will evaluate the communications process for critical systems where action must be taken within relatively short timeframes. Where applicable, improvements to these systems can reduce the time required to detect and respond to an unintended release, thus reducing the consequences.

All personnel responsible for monitoring release detection system data/alarm functions will be properly trained in the operation and maintenance of the system. Pipeline controller training will include the process to recognize and analyze release detection alarms and basic concepts of pipeline hydraulics (steady state and transient).

The technology to detect unintended releases from pipelines is undergoing continual development and improvement. Therefore, new and improved technology will be considered with any release detection decision. Types of release detection systems are described in detailed in API Guide #1162 Section 10.3.2.

Improved Emergency Response

The operator will comply with all emergency response requirements contained in 49 CFR 195. In addition, the operator will take measures to improve the emergency response program to help prevent and mitigate the consequences of a pipeline failure that could affect an HCA. These measures include providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls as necessary.

Isolation and Control of the Release Source

The source of an active unintended release needs to be immediately controlled. Control measures may vary depending on the release volume, rate, location, and pipeline operational capabilities. The primary methods of source control for an active unintended release are:

- Reduction of pipeline operating pressure
- Total shutdown of pipeline product flow and closure of release source area line valves, when applicable

- Isolation of pipeline segment containing the release by closing main line block valves or other mechanisms

Operator operating personnel have the authority and responsibility to reduce operating pressures and /or stop flow of pipeline product in emergencies.

Pipeline Operating Pressure Reduction

Operating pressure reduction is used as both a temporary and occasionally permanent measure to reduce risk. Operating pressure reduction is a temporary, but immediate initiative action, to reduce risk until a defect can be evaluated by excavation, repaired or removed. In some cases, the operator may determine that the consequences of a failure are significant enough to design for a higher level of safety than normally afforded by ASME B31.4. An operating pressure reduction can provide benefits similar to a hydrostatic test, but a larger margin of pressure reduction may be necessary.

Section 6.3 Risk Analysis Application (Protocol 6.02)

The operators will 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. The operator shall:

1. Consider 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. Make sure risk analysis variables are defined such that the impact of preventive and mitigative measures on risk to pipeline segments can be evaluated.
3. 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).

Section 6.4 Decision Basis (Protocol 6.03)

The operator will decide if potential actions are to be implemented or rejected and is a critical part of the preventive and mitigative measure process. The operator will include:

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. 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.

Section 6.5 Leak Detection Capability Evaluation: Evaluation Factors (Protocol 6.04)

There are many ways that an operator may detect leaks. An operator must determine if modifications to its leak detection means are needed to improve the operator's ability to respond to a pipeline failure and protect HCAs.

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. The operator should address the following:

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 shortterm 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.

Section 6.6 Leak Detection Capability Evaluation: Operator Actions/ Reactions (Protocol 6.05)

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. The operator shall include the following:

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.

Section 6.7 EFRD Need Evaluation: Factors (Protocol 6.06)

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.

Additional Guidance:

An EFRD is a device that can limit the amount of product released as a result of a leak or rupture. An EFRD is defined by the rule as either a check valve or a remote control valve. Based on the results of a risk analysis of its pipeline systems, the operator will make evaluations to determine the need to install additional EFRDs on a pipeline segment to protect an HCA. In making this determination, at least the following factors will be considered:

- Capability and swiftness of leak detection method to detect leak including consideration of system detection times, operator response times, remotely controlled valve response characteristics, and system isolation time assessments, as applicable,
- Time required to shut down pipeline
- Type of commodity transported
- Potential leak rate
- Potential volume that could be released
- Pipeline topography or elevation profile
- Potential for ignition
- Proximity to power sources
- Location of nearest response resources
- Terrain between release site and HCA
- Benefits expected by reducing spill volume

The operator will also consider additional relevant line-specific factors beyond those listed in 195.452(i)(4) as follows:

- Relative reliability of existing or proposed EFRDs
- Any relevant operating modes beyond nominal full flow conditions
- Evaluation of the need for additional EFRDs to respond to releases during transient conditions
- 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

Because of the significant variation in pipeline design and operation, the physical characteristics of the land and waterways near pipelines, and the different nature and location of HCAs EFRD installation criteria are at the discretion of the operator based on sound engineering and evaluation of their system.

All EFRD data and evaluation material shall be retained for the IMP records.

Diagrams:

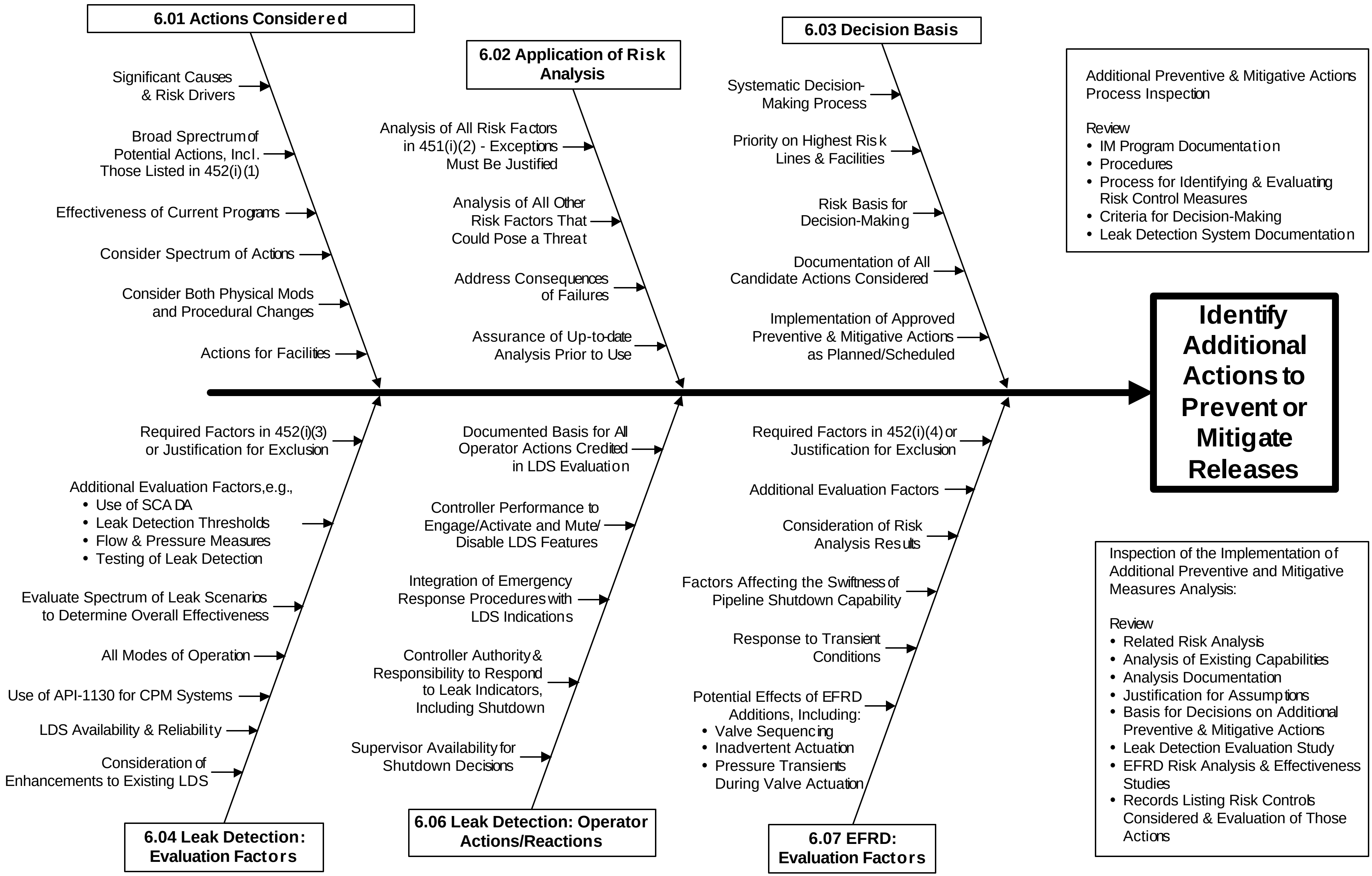
1. Protocol 6 Preventive & Mitigative Measure Fishbone Diagram

Records:

1. Latest Edition of Integrity Management Inspection Protocols.

Additional Preventive & Mitigative Actions

Additional Guidance Overview



Note: LDS - Leak Detection System

Hazardous Liquid Integrity Management Plan
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Element 7
Program Evaluation

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Section 7.1 Introduction

This element 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 element 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.

Section 7.2 Program Evaluation: Process for Measuring IM Program Effectiveness (Protocol 8.01)

The operator's IM Program includes a process to measure whether the program is effective in assessing and evaluating pipeline integrity and in protecting the high consequence areas. The operator will use the following approach:

1. Include the use of periodic self-assessments, internal/external audits, management reviews, performance measures, or other self-critical evaluations to assess program effectiveness.
2. Include a description of the scope, objectives, and frequency of program evaluations.
3. Include bench-marking operator performance using data from outside the operator (e.g., API's Pipeline Performance Tracking System).
4. Define the use of performance metrics in evaluating program performance.
5. Provide for feedback to corrective action programs, preventive and mitigative measure decisions, and the threat and risk analysis.
6. Assure management awareness and commitment, including the resources required to address integrity management program improvements identified through performance measurement.
7. Include provisions for the assignment of responsibility, by organization, group, or title, for implementation of required actions.
8. Include provisions for the review and follow-up of program evaluation results, findings, and recommendations, etc., by appropriate operator managers.

The adequacy of specific performance measures is the subject of Protocols 8.03 and 8.04.

Additional Guidance:

Performance Measures Process

Program evaluation is an ongoing process to measure, assess and evaluate program and piping system performance using both leading and lagging performance metrics. Effective corrective actions addressing the evaluation outcomes should be taken to improve both programmatic activity and pipeline system performance and integrity. Leading and lagging indicators are defined as:

- Leading indicators measure the accomplishment and effectiveness of operator programs and activities to control risk. They provide insight into how well the operator is implementing the various elements of its IM or safety management program.
- Lagging metrics measure the outcomes of the programs and activities to manage risk. They provide the documented success or failure of these activities (results).

The performance measures required will depend on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment. The operator will select a set of measurements to judge how well its program is performing. The operator’s objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. This IMP program contains many elements. Therefore, several performance measures will be used to measure the effectiveness.

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

1. Selected Process Measures–Measures that monitor the surveillance and preventive activities the operator has implemented. These measures indicate how well an operator is implementing the various elements of its integrity management program.
2. Deterioration Measures–Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.
3. Failure Measures–Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

The operator can choose from the list of performance measures the located in 195 Appendix C and/ or Table 13.1in API 1160.

<u>Once per calendar year, not to exceed 18 months</u>, the operator will collect performance information and evaluate the effectiveness of its integrity assessment methods, and its preventive and mitigative risk control activities, including repair. The operator will also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions.

The operator will define 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. The operator will also bench-mark operator performance using data from outside the operator. For example: agency reports, and Pipeline Association for Public Awareness (PAPA).

The operator expects the IMP will evolve and improve as experience is gained, and measurement of whether the program is effective is important in guiding that evolution.

A combination of performance measures and system audits will be implemented to evaluate the overall effectiveness of the IMP program.

Ultimately, the performance measurement of the operator's integrity management program is the degree to which unintended releases are eliminated. The operator will have a minimum of six performance measures. These six performance measures shall include a distribution of leading, lagging, and deterioration measures. These six performance measures shall be based on an understanding of the failure mechanisms or threats to integrity for each pipeline system operated. The distinction between many of these measures will not always be clear.

Audits of integrity management programs are an important element of evaluating program effectiveness and identifying areas for improvement. Audits may be performed by personnel within the organization (self assessments), by auditors from outside organizations (third party consultants), or by agencies.

The scope of the audits will be threefold. First, process activities required by 49 CFR 195 will be reviewed using the OPS protocol checklist found on the OPS website. The second audit type will be a complete review of the integrity management program to ensure all activities are performed accurately and in a timely manner. Lastly, the audit review shall include a review of the performance measures to determine if they should be updated to more accurately measure the program.

Additional audits/program evaluations may be initiated due to management of changes issues like change in management or key IMP personnel, or when key operating parameters change.

Section 7.3 Program Evaluation: Records Demonstrate IM Program Effectiveness (Protocol 8.02)

For evaluating IM Program performance the operator will have the following records for evaluating IM Program performance:

1. Records show that periodic self-assessments, internal and/or external audits, management reviews, or other self-critical program evaluations have been performed at the established frequency.
2. Records indicate that the process has been implemented consistent with its scope and objectives, and at the established frequency.
3. Records show that integrity management program evaluations provide a comprehensive and in-depth examination of performance, and effectively used the established performance metrics in the process.
4. Records show bench-marking performance using data from outside the operator (e.g., API's Pipeline Performance Tracking System).
5. Records show evidence of feedback to corrective action programs, preventive and mitigative measure decisions, and the threat and risk analysis.
6. Records include the assignment of responsibility, by organization, group, or title, for implementing required actions.

7. Records show that deficiencies identified in integrity management program evaluations and recommended improvements have been implemented in a timely manner.

Section 7.4 Program Evaluation: Process for Defining Performance Metrics (Protocol 8.03)

The operator process for selecting performance metrics to measure the effectiveness of the IM Program includes:

1. A description of the performance metrics to be used and the frequency for data collection.
2. Defines metrics that:
    a. Provide an overall measure of program effectiveness such as number of leaks, volume released, etc.,
    b. 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, and
    c. Provide threat-specific insight, 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.
3. Performance metrics developed in accordance with Appendix C, specifically:
    a. Activity Metrics that monitor the surveillance and preventive activities that are in place to control risk. These metrics indicate how well an operator is implementing the elements of its integrity management program.
    b. Deterioration Metrics that monitor operational and maintenance trends to indicate if the program is effective or ineffective, or the desired outcome is being achieved or not, despite the risk control activities in place.
    c. Failure Metrics that reflect whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure the number of releases, the volume spilled, per cent recovered, etc.
4. Trending of equipment or material failures (e.g., valve gaskets or pump seals) 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 (e.g., significant enough to warrant corrective action).
5. 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, or other abnormal operations such as those listed in 195.402(d)? Leading indicators measure the effectiveness of proactive efforts. These indicators can uncover weaknesses before they develop into fullfledged problems.
6. Periodic review and revision (if needed) of performance metrics to assure they are providing useful information about the effectiveness of IM Program activities.
7. Ensure the completeness and accuracy of performance measure data – both for metrics reported to PHMSA and the metrics used internally.
8. Performance goals, including segment-specific issues related to the operator's unique operating environment such as a decrease in the number, and depth, of corrosion related anomalies, a decrease in the threat of mechanical damage due to a decrease in one-calls, a

change in operations resulting in a decrease in pressure cycles, a decrease in the number of crack anomalies, etc.

9. Periodic review of performance goals and their revision (if needed) based on the results of program evaluations.
10. Compare leak, failure, and incident metrics to risk model results, and uses these comparisons to modify the risk model as necessary.

Section 7.5 Program Evaluation: Records Demonstrate Effective Use of Performance Metrics (Protocol 8.04)

The operator will have the following records for evaluating IM Program effectiveness:

1. Records show the performance measure data is being collected and at the frequency established in the program evaluation process.
2. Records show that overall metrics have been defined and data collected for:
    a. Overall measures of program effectiveness such as number of leaks, volume released, etc.,
    b. Metrics 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, and
    c. 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.
3. Records show that the performance metrics developed in accordance with Appendix C were implemented. Specifically,
    a. Activity Metrics that monitor the surveillance and preventive activities that are in place to control risk. These metrics indicate how well an operator is implementing the elements of its integrity management program.
    b. Deterioration Metrics that monitor operational and maintenance trends to indicate if the program is effective or ineffective, or the desired outcome is being achieved or not, despite the risk control activities in place.
    c. Failure Metrics that reflect whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure the number of releases, the volume spilled, percent recovered, etc.
4. Records show trending of equipment or material failures as a means to evaluate pipeline deterioration.
5. Records show trending of leading indicators such as inadvertent over-pressurization, ROW encroachments without one-call notification, SCADA outages, operation of overpressure or other safety devices, or other abnormal operations such as those listed in 195.402(d).
6. Records show that the performance metrics have been reviewed and updated if needed to assure they are providing useful information about the effectiveness of IM Program activities.
7. Records show that the operator has implemented its program to assure the completeness and accuracy of the data used to measure performance.
8. Records show that the IM performance measures reported to PHMSA are complete and accurate.

9. Records show that the operator has established specific performance goals, including segment specific issues related to the operator's unique operating environment such as the number, and depth, of corrosion related anomalies, the threat of mechanical damage due to one calls, a change in operations resulting in pressure cycles, the number of crack anomalies, etc.
10. Records show that the performance goals have been reviewed and revised based on the results of program evaluations.
11. Records show that the leak, failure, and incident metrics have been compared to the risk model, and that changes to the risk model have been made when the data indicates such changes are necessary.

Section 7.6 Program Evaluation: Communication of Evaluation Results (Protocol 8.05)

The operator will communicate the results of program effectiveness to the proper areas/personnel in the operator that may need to utilize the information:

1. Reports on the IM Program performance 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. Show management awareness and commitment, including providing resources to address improvements identified by the integrity management program evaluation.
4. Records include the review and follow-up of program evaluation results, findings, and recommendation, etc., by appropriate operator managers.
5. Management follow-up of significant integrity issues and actions taken to address these issues.

Section 7.7 Program Evaluation: Root Cause Analysis Process (Protocol 8.06)

The insights obtained from root cause analysis of incidents, leaks, and near-misses can be important to improving performance. The operator should use root cause analysis, generate lessons learned and communicate this to the organization:

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 operator employees.

Additional Guidance:

Root cause analysis/failure investigation procedures will be used to help determine causes of failures and make improvements in the IM program.

Section 7.8 Program Evaluation: Process Revision and Document Control (Protocol 8.07)

Documentation will be maintained that supports the decisions and analyses made to implement the Integrity Management Program. The operator's revision and document control process includes:

1. 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. 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 (VI), 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.

Section 7.9 Program Evaluation: Process Formality (Protocol 8.08)

Each element of an effective operator program should 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.

Diagrams:
1. Protocol 8 Program Evaluation Fishbone Diagram

Records:

1. Latest Edition of Integrity Management Inspection Protocols.

Continual Evaluation & Assessment Additional Guidance Overview