TRANSMONTAIGNE

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June 29, 2007

Linda Daugherty
Director, Southern Region
Pipeline and Hazardous Materials Safety Administration
223 Peachtree Street, Suite 600
Atlanta, GA 30303

RE:CPF 2-2007-6005M

Dear Ms. Daugherty,

Find enclosed TransMontaigne's response to NOA CPF 2-2007-6005M. If upon review you require further assistance, please feel free to contact us. Additionally, we would like to thank you for providing us an extended due date to respond.

Respectfully yours,

Fred L. Dennis
Director, Regulatory Compliance
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NOA Response CPF 2-2007-6005M

1. 195.452(~)(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

a. Transmontaigne must amend its procedure to ensure a formalized and documented process for revisions that affect the integrity management plan (IMP).

TMG Response: Revision Section amended to document process.

Review and Revision History

Section	Date	Details
	11/13/2002	Original Plan with Baseline Assessments
	01/17/2003	Revision – Plan 2.doc David Wint
	11/08/06	Plan re-formatted to reflect US DOT/OPS revised Protocol Form dated 10/11/06
Revision	6/5/2007	Added a revision process per DOT NOA
Section 8.01	6/5/2007	Revised 1st paragraph & added Appendix G to document integrating risk analysis information per DOT NOA
Section 8.01	6/5/2007	Revised 1st paragraph and added paragraphs 2 & 3 to reflect PHMSA Annual Report requirement.
Section 6.03	6/5/2007	Amended to provide documentation of P&M actions considered or taken per DOT NOA
Section 7.05-7.08	6/5/2007	Replaced Direct Assessment Guidelines with Sections 7.05 – 7.08 per regulatory amendment
Section 4.01	6/5/2007	Amended to clarify when discovery of a condition occurs. Added Repair Schedule Flow Chart

TransMontaigne will follow the following process for documenting revisions to our Integrity Management Manual.

TransMontaigne will follow the following process for documenting revisions to our Integrity Management Manual.	**Section Revision Date:**

Comments from Operations

Comments and changes from field operating personnel are to be sent as they are instituted to the Director of Pipeline Operations. Operations personnel should use pencil notes on the pages of the Integrity Management Manual, or insert additional pages if necessary, to reflect their comments or changes to procedures. The Director of Pipeline Operations shall each year review the procedures prior to updating the manual. The Director of Pipeline Operations shall assure that each issued copy of the pipeline manual is current and complete.

Changes in Regulations

The Director Regulatory Compliance shall check if any amendments have been made to the government regulations that need to be incorporated into the manual. Refer to http://ops.dot.gov/regs/regsindex.htm for regulatory activity affecting TransMontaigne's Integrity Management Program or other industry association notification process.

Revising Integrity Management Manual

Revisions to manuals shall be made by revising sections or subsections as appropriate. Pages should carry the revision date.

A revision summary document is to be prepared and permanently filed that explains any change, including justification for the change, and lists the page(s) that have been revised. In addition a revision log will be updated summarizing each revision and effective date to ensure that the revision issue is received by all of the manual holders and that it is properly incorporated into their manual.

Each time the manual is revised; the Revision Log Sheet in the front of the manual shall be revised and replaced.

Issuing Revisions

Each revision shall be issued by a written transmittal sheet. The transmittal sheet should explain step-by-step how each section or subsection is to be incorporated into the manual such as: "Remove Procedure 6.1 "Maintenance and Inspection Schedule" in its entirety and replace it with the revised procedure."

The transmittal sheet should list all manual holders. Use an arrow or outline block around the manual holder's name on the transmittal sheet to indicate the recipient of the revision.

Updating Each Manual

Each manual holder is responsible for maintaining his/her copy of the manual. When a revision is received, check the transmittal sheet and the revision summary to ensure that all revised pages have been received. Follow the instructions of the transmittal to update the manual.

Be sure that all operations personnel study the revised manual to be aware of the new procedures.

Reporting

The transmittal sheet and revision summary serves as the reporting documentation for the revised manuals.

Additionally, the Director of Pipeline Operations should maintain a file documenting the review process, stating the documents that were reviewed, summary of findings, and changes that resulted.

Justification: Document revision process and respond to DOT NOA

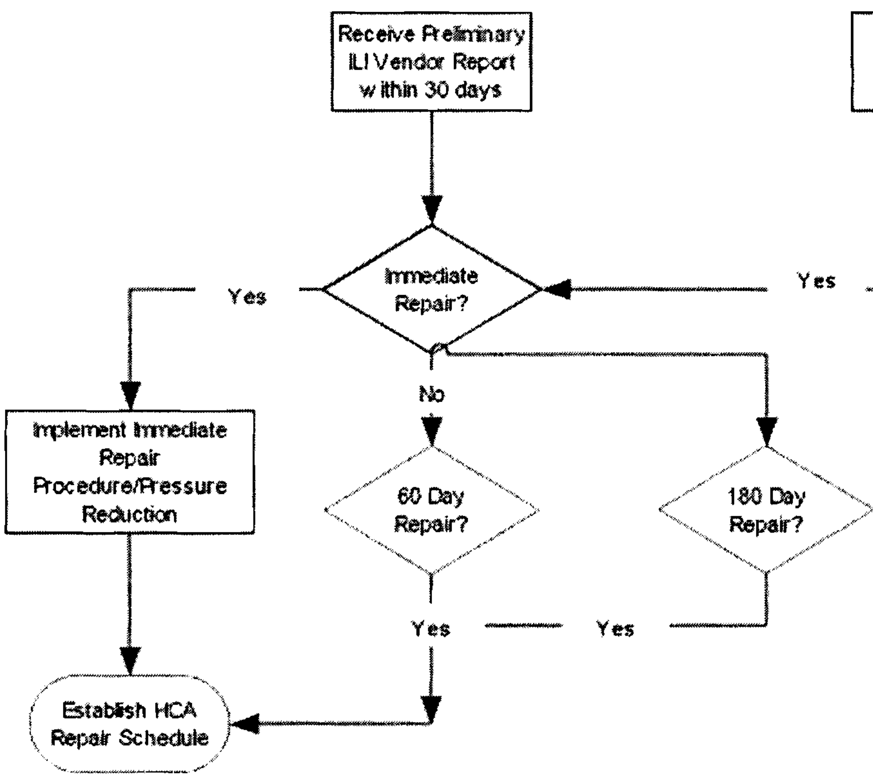
2. 195.452(h)(2) Discovery of a condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline.

a. TransMontaigne must amend its procedure to define and document when discovery occurs.

TMG Response: Revised Section 4.01 1st paragraph – Discovery of Condition Process

Bold t ype revised language…

Remediation of the ILI anomalous conditions will consider the definition on page 8, Definitions of when discovery of a condition occurs. This date will be documented, and used to determine the remediation schedule that will be completed according to a schedule that categorizes the anomalies into the four repair criteria conditions per 49 CFR §195.452(h)(1) - (4). These categorized conditions will then be prioritized for evaluation and remediation. The evaluation and repair schedule must also take into consideration the HCA(s) risks score at the anomaly location and any scheduling logistics. If the schedule cannot be met, TransMontaigne will justify the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. If the schedule cannot be met and the pressure of the pipeline cannot be reduced to a safe level, OPS must be notified by the Regulatory Manager (**Section 3.08**). See flowchart below:



Justification: To clarify when discovery of a condition occurs and respond to DOT NOA

3. 195.452(f) What are the elements of an integrity management program? (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure.

a. TransMontaigne must amend its procedure to document the process of integrating risk analysis information and other information utilized to characterize the risk of pipeline segments.

TMG Response: Amended Section 8.01 1st pargraph and added Appendix G to document integrating risk analysis information process.

Bold type revised language...

The risk management team will meet on a regular, scheduled frequency. **This will consist of at a minimum an annual meeting to integrate TransMontaigne's risk analysis information**. The team will also evaluate internal risk management processes and conduct benchmarking of industry peers to identify and apply "best practices". The team will also evaluate and confirm that processes identified and recommended for implementation are aligned with the corporate strategies. **If the results are not consistent with TransMontaigne's understanding and expectations of the entire system's operation and HCA risks, TransMontaigne will explore the reasons why and make appropriate adjustments to the method, assumptions, or data. The Risk Management Team will be responsible for the following:**

Appendix G – Direct Integration of Risk Analysis Information Process

The following issues in the form of a meeting agenda will be considered during the annual informational review of TransMontaigne's risk analysis process. This process shall be followed and an Annual Report documented for each Annual Integrity Management Review Meeting

BAP Informational Analysis update as per 195.452(d)(3)

1. Update as necessary Segment Ranking developed by American Innovation (formerly Bass Trigon) based on any new information or newly identified HCA's. See **Section 5.02** guidance and example 2006 Meeting Agenda listed below:

- Results of previous integrity assessments, defect type and size that the assessment method can detect, and defect growth rate;

- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness);
- Leak and incident history, repair history, and cathodic protection history;
- Product transported;
- Operating stress level;
- Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities, and development or planned development along the pipeline;
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);

Geo-technical hazards;

- Physical support of the segment such as by a cable suspension bridge;
- Corrosion control information (e.g., test station readings, close interval survey results);
- Operating parameters (e.g., maximum operating pressure, pressure cycle history); and
- Information about how a failure could affect a high consequence area, such as the location of a drinking water intake.

TransMontaigne Product Services, Inc. AMERICAN INNOVATIONS
Pipeline Integrity Management Plan Review / Pre Audit Meeting — Integrity Management Division

ITEMS FOR DISCUSSION

TRANSMONTAIGNE / AMERICAN INNOVATIONS IMD

November 21 2006
ATLANTA, GA

Attendees:

- Jim Dugan
- Ed Leubke
- Elaine Hendren

Tuesday, November 21st

1. **Introductions** .... 8:00 – 8:30 am
   1.1. Introduction
   1.2. TPSI Pipeline Integrity Management Plan and AI-IMD Support
   1.3. Integrity Issues and Potential Integrity Trends
2. **2005 Algorithm and Risk Model Revisions** .... 8:30 – 9:30 am
   2.1. Risk Algorithm Review
   2.2. Database and Algorithm Evaluation Report
   2.3. Revisions to Segment Identification Analysis
3. **Break** .... 9:30 – 9:45 am
4. **2006 Database Revisions and Risk Ranking Results** .... 9:45 – 10:30 am
   4.1. IAP™ Version 5.80 Refresher
   4.2. Asset Data Changes
   4.3. 2006 Performance Data Integration
   4.4. Risk Ranking Results Review
5. **Program Evaluation / PHMSA Protocols Self-Assessment** .... 10:30 am – 12:00 pm
6. **Lunch** .... 12:00 – 1:00 pm
7. **Program Evaluation / PHMSA Protocols Self-Assessment** .... 1:00 – 2:00 pm
8. **Break** .... 2:00 – 2:15 pm
9. **Program Evaluation / PHMSA Protocols Self-Assessment** .... 2:15 – 3:30 pm
10. **Final Review / Planning** .... 3:30 pm – 4:00 pm
    10.1. Critical IM Program Issues
    10.2. Path-forward
    10.3. Outstanding Items / Open Discussion
    10.4. Meeting Adjourns

2. Identify any changes or additional integrity assessment methods that should be considered to assure assessment are adequate to establish pipeline integrity.

3. Identify any revisions required to update the Integrity Management Plan to reflect actual IM process, inclusion of all pipeline systems/breakout tank facilities, dates of assessments, corrections, etc.

4. Assure credit for any Integrity Management Training that has been documented.

Preventive and Mitigative Measures

5. Re-evaluate P&M candidate measures and update list as required utilizing the last EFRD study. Use those factors listed below, **Section 6.02*** and also reconsider other additional measures identified in **Appendix E*** for all pipeline HCA segments.

- Develop a proposed candidate list of P&M measures including a cost analysis for major capital expenditures
- Develop schedule to implement P&M measures including documenting justification for any proposed action not considered.
- For major projects, identify relatively simple interim measures that can be taken to reduce risk while major projects are being implemented.

***Section 6.02**

TransMontaigne will consider all relevant risk factors to a particular pipeline segment. This includes risk factors that influence both the likelihood and the consequences of pipeline failure. This would include design and construction information, maintenance and surveillance activities, operating parameters and operating history, right-of-way information, information about the population and the environment near the pipeline, etc. The risk analysis conducted by the Risk Management Team to determine if additional preventive or mitigative action is required will also include a re-evaluation of the following specific risk factors to assure the risk factors are up to date:

:

- terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
- elevation profile;
- characteristics of the product transported;
- amount of product that could be released;
- possibility of a spillage in a farm field following the drain tile into a waterway;
- ditches along side a roadway the pipeline crosses;
- physical support of the pipeline segment such as by a cable suspension bridge;
- exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

*Appendix E

Specific Preventive and Mitigative Measures to Consider for HCA Types				
Abbreviation	**Action Category**	**Type Action**	**Specific Actions to be Considered**	**Comments**
DP	**Damage Prevention (1)**	**Preventative**	One-Call Utility Locating Systems	
			Improved Line Marking	
			Increased Cover over Pipeline	
			Mechanical Pipe Protection	
			Improved Public Education	
			Improved Contractor Education	
			Improved R/W Clearing	
			Remove R/W Encroachments	
			Improved Pipeliner Training/Procedures	
			Increased R/W Aerial Surveillance	
			Increased R/W Ground Surveillance	
			Buried Pipeline Warning Tape	
CEC	**Control of Ext Corrosion (2)**	**Preventative**	Increased Monitoring or Rectifiers	
			Improved Follow-up to Low CP Levels	
			Repair Pipeline Coatings	
			Replace Bare with Coated Pipe	
CIC	**Control of Internal Corrosion (3)**	**Preventative**	Increased Monitoring of Inhibitors	
			Corrosion Coupon Monitoring	
			Routine Cleaning Pig Runs	
			Clear Casing Shorts	
RLV	**Reduction of Leak Volumes (4)**	**Mitigative**	Upgrade Leak Detection System	
			Install EFRD	
			Improved Emergency Response	
RII	**Reduce Inspection Intervals (5)**	**Preventative**	Increase Frequency of Aerial Patrol	
			Increase Frequency of Ground Patrols	
			Increase Frequency of Corrosion Control Checks	
ET	**Enhanced Training (6)**	**Preventative**	Risk Specific Training for Maintenance Crew	
DER	**Drills w Emergency Responders (7)**	**Mitigative**		
NRO	**Natural Resources Org Response (8)**	**Mitigative**		

(1) Suggested Damage Prevention actions should be researched in the 'Common Ground Alliance' report on 'Best Practices'
(2) External Corrosion Control actions should be reviewed with the area corrosion control manager.
(3) Internal Corrosion Control actions should be reviewed with both the area Manager Corrosion and the Product Quality Control Department of the Shipper
(4) Leak Reduction actions shall be reviewed by the pipeline operations department and the area operations engineering department
(5) Reduced Inspection Interval actions shall be reviewed by Field Maintenance Groups and Corrosion Control Department
(6) Enhanced Training actions shall be reviewed by specific maintenance department and area engineering department
(7) Drill with Emergency Responders from HCA response district shall be coordinated by field maintenance and HES department
(8) Response of Natural Resources Organizations shall be coordinated by ESOH department

Leak Detection Capability

6. Re-evaluate the need for new or improved leak detection capability to protect HCA's – See following Section 6.06 for characteristics to consider, and Section 6.07 for proposed actions.

Section 6.06

TransMontaigne's Operations Control Manager will conduct an on-going evaluation process to evaluate the need for improving the leak detection capability. The evaluation includes at least the following factors: length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. Additionally, the following characteristics will also be evaluated:

- The system operating characteristics (e.g., steady state operation, high transient pressure and flow),
- 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,
- Specific consequences related to sole source water supplies regarding additional leak detection means,
- Testing of leak detection means, such as physical removal of product from the pipeline to test the detection, and
- Any other characteristics that are part of the system leak detection.

Section 6.07

TransMontaigne SCADA system currently has leak detection monitoring operational on the majority of its liquid lines and is continuing to develop real time monitoring on additional liquid lines that could affect HCAs. The reliability and effectiveness of its monitoring systems will be studied and improvements made as appropriate.

Emergency Response, Integrated Spill Contingency Plans, and Control Center Operations procedures are available that help minimize the size of an unintended release. The size of the release depends upon many things including leak size, release rate and location, and pipeline operational capabilities.

The primary means of controlling a release include:

- Reduction of pipeline operating pressure,
- Shutting down of the pipeline flow, and
- Isolating the section of the pipeline leaking by closing appropriate block valves.

TransMontaigne has assured that operations control center personnel have the authority and responsibility to reduce operating pressure and/or stop flow of the pipeline at all times. Controllers with this responsibility have clear and concise instructions to act immediately when the situation warrants.

Emergency Flow Restricting Device - EFRD

7. Conduct EFRD evaluation to determine if an EFRD is required to protect an HCA. This process has initially been completed by Integrity Solutions and a baseline report issued on November 27, 2006 **Prevention and Mitigation Measures Emergency Flow Restriction Device Study.** The annual evaluation will include an analysis of any system changes (pressure, flow rate, new HCAs) that would require updating the last EFRD evaluation that is maintained in the Integrity Management files.

Variances

8. TransMontaigne will annually review the need to request a variance for the upcoming year's IMP work and will make an application to PHMSA accordingly.

Performance Measures Analysis – Section 8.01

9. Identify any additional performance measures per Section 8.01* (Part 195 Appendix C (Attachment 1) and API Std 1160, Section 13, "Program Evaluation" that would improve determining the effectiveness of the IM Process.

*Section 8.01, Attachment I -Appendix C, and Attachment II - API 1160, Section 13 provided below for guidance:

A performance measure analysis will be used to determine the effectiveness of the integrity program with the following overall program measures:

- Reduce the total number unintended releases. Zero releases are the ultimate goal.
- Reduce the total volume occurring with unintended release (based on a threshold of five gallons). A zero volume released is the ultimate goal.
- Reduce the number of unscheduled shutdowns.
- Reduce the overall risk by comparing previous risk level scores identified in the TransMontaigne BT Risk Model.

- Document the improvements made to the management process to address the lowering of risk and the overall effectiveness of the program.

Attachment 1 – Part 195 – Appendix C

Examples from Appendix C

Measures should include leading indicators, lagging indicators, process measures, measures of deterioration and measures of actual failures or releases. TransMontaigne will consider the recommended performance measurements as described in Appendix C of the rule: Examples of performance measures from Appendix C are:

a. A performance measurement goal to reduce the total volume from unintended releases by______% with an ultimate goal of zero.

b. A performance measurement goal to reduce the total number of unintended releases (using a threshold of 5 gallons) by___ % with an ultimate goal of zero.

c. A performance measurement goal to document the percentage of integrity management activities completed during the year.

d. A performance measurement goal to track and evaluate the effectiveness of the operator's community outreach program.

e. A narrative description of the pipeline system's integrity including a summary of performance improvements both qualitative and quantitative be prepared periodically.

f. A performance measure based on internal audits of the operator's pipeline system.

g. A performance measure based on external audits of the operator's pipeline system.

h. A performance measure based on operational events that have the potential to adversely affect pipeline integrity (e.g., relief occurrences, unplanned valve closures, SCADA outages).

i. A performance measure to demonstrate that the operator's IM program reduces risk over time with a focus on high risk items.

j. A performance measure to demonstrate that the operator's IM program for pipeline stations and terminals reduces risk over time with a focus on high risk items. If the operator does not use the performance measurement guidance of Appendix C, determine if the selected performance measurements provide an equivalent level of performance measurement.

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

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

(1) Information an operator may use to identify a high consequence area and factors an operator can use to consider the potential impacts of a release on an area;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(8) The hydraulic gradient of the pipeline.

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

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

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

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

II. Risk factors for establishing frequency of assessment.

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

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

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

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

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

(5) Cathodic protection history.

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

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

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

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

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

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

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

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

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

(15) Operating stress levels in the pipeline.

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

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

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

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

i. For the baseline assessment schedule, we would plan to assess 50% of all pipeline segments covered by the rule, beginning with the highest risk segments, within the first 3½ years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two (2) years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk segments no later than year five (5).

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

Age of pipeline: assume 30 years old (refer to "Age of Pipeline" risk table)–
Risk Value=5
Pressure tested: tested once during construction–
Risk Value=5
Coated: (yes/no)–yes
Coating Condition: Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)–
Risk Value=5
Cathodically Protected: (yes/no)–yes–Risk Value=1
Date cathodic protection installed: five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline's construction is generally considered low risk.)–Risk Value=3
Close interval survey: (yes/no)–no–Risk Value =5
Internal Inspection tool used: (yes/no)–yes. Date of pig run? In last five years–Risk Value=1
Anomalies found: (yes/no)–yes, but do not pose an immediate safety risk or environmental hazard–Risk Value=3
Leak History: yes, one spill in last 10 years. (refer to "Leak History" risk table)–Risk Value=2
Product transported: Diesel fuel. Product low risk. (refer to "Product" risk table)–Risk Value=1
Pipe size: 16 inches. Size presents moderate risk (refer to "Line Size" risk table)–Risk Value=3

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

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

LEAK HISTORY

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

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

LINE SIZE OR VOLUME TRANSPORTED	
Safety risk indicator	Line size
High	≥ 18"
Moderate	10"–16" nominal diameters
Low	≤ 8" nominal diameter
AGE OF PIPELINE	
Safety risk indicator	Age Pipeline condition dependent[1]
High	> 25 years
Low	25 years

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

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

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

IV. Types of internal inspection tools to use.

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

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

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

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

V. Methods to measure performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(10) results of the baseline integrity assessment;

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

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

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

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

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

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

(17) other remedial actions planned or taken;

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

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

(20) criteria for determining EFRD installation;

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

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

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

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

A. Any change since the previous assessment.

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

C. An anomaly abrupt in nature.

D. An anomaly longitudinal in orientation.

E. An anomaly over a large area.

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

[Amdt. 195-70, 65 FR 75378, Dec. 1, 2000 as amended by Amdt. 195-74, 67 FR 1650, Jan. 14, 2002]

Justification: Amend Section 8.01 to document integrating risk analysis information process and respond to DOT NO A.

4. 195.452(i)(l) An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area.

a. The Transmontaigne integrity management plan states that the Transmontaigne Risk Management Team will provide a proposed candidate list of actions for risk reduction within one year following completion of an assessment, or whenever enough new information is available that would necessitate implementing preventive and mitigative measures. Transmontaigne must amend its procedures for documenting the actions that are considered or taken.

TMG Response: Amended Section 6.03 to provide documentation of P&M actions considered or taken per DOT NOA.

Implementing preventive and mitigative actions is highly dependent on the proposed risk control activity. Some actions may be simple "quick fix" activities (additional line markers) that can readily be implemented in the field. Other actions (pipe replacement) may involve major capital expenditures and require significant time for budgeting, engineering and design, and implementation. Because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions. TransMontaigne's Risk Management Team however, will provide a proposed candidate list of actions for risk reduction within one year following completion of an assessment, or whenever enough new information is available that would necessitate implementing addition preventive and mitigative measures. This submittal will include a cost analysis for those actions involving major capital expenditures. **TransMontaigne conducted a baseline study of the HCAs (see Facilities Risk & Prevention and Mitigation Measures Study, November 27, 2006). A list of candidate P&M measures summarizing proposed actions are maintained in the Integrity Management Files.** The Director of Pipeline Operations will develop a schedule by when additional preventive and mitigative measures will be taken, document justifications for those proposed actions not considered, and act as quickly as practical after identifying the need for such risk controls. In situations where lengthy periods are required for implementation, TransMontaigne will also evaluate whether there are relatively simple, interim measures that can be taken to reduce risk while major projects are being implemented. Line segments will be reviewed annually with ROW activity, patrol reports, Integrity Assessment results, and other activities being used as basis for implementing new or additional PM&M measures.

	System Name	Length (miles)	Age	PM&M Measures Recommended	PM&M Measures Implemented	Date of Baseline Assessment
1	Razorback 8"	66.7	1989	R,CP,UPT,PE,ROW	R,CP,UPT,PE	2004
2	MB 10"	17.4	2000	ROW,CP,R,UPT,PE	PE,ROW,R,CP	2006
3	Collins 36" Line 9361	.88	1981	DA,CP,ROW,PI,PE	Pending	2007
4	Collins 24" Line 600	.35	2002	DA,CP,ROW,PI,PE	Pending	2007
5	Collins 36" (L8361)	.87	1981	DA,CP,ROW,PI,PE	Pending	2007
6	Collins 8" Line 9081	.95	1973	DA,CP,ROW,PI,PE	Pending	2007
7	Collins 18" Line 9181	.89	1973	DA,CP,ROW,PI,PE	Pending	2007
8	Collins 24" Line 79	.41	1957	DA,CP,ROW,PI,PE	Pending	2007
9	Collins 24" Line 78	.38	1957	DA,CP,ROW,PI,PE	Pending	2007
10	Pinebelt 8"	34.22	1957	CP,ROW,ILI, PI	ILI,PI,CP	2006
11	Bellmeade 8"	1.14	1999	CP,ROW,ILI	CP	2004

Key:

- Increased right-of-way patrol frequency – (ROW)
- Update cathodic protection data – (CP)
- Repair anomalous conditions that are integrity threats – (R)
- Update pressure test records – (UPT)
- Improved public education – (PE)
- Update in-line inspection records – (UILI)
- Coating performance inspections (bell hole inspections) – (CI)
- Caliper or Inertial survey in-line inspection (if possible) – (ILI)
- Pipe Condition performance inspections (bell hole inspections) – (PI)
- Pressure test records update or assessment – (PT)

Justification: Amend Section 6.03 to P&M actions considered or taken per DOT NOA.

5. 195.452(f) What are the element of an integrity management program? (7) Methods to measure the program's effectiveness.

a. The TransMontaigne integrity management plan states that an annual evaluation will be done to review the effectiveness of the integrity management program. The annual program evaluation is scheduled to be completed by September 30th of the following year. The IMP must include adequate documentation of the program evaluation when completed.

TMG Response: See attached TMG Annual IMP Evaluation Report CY 2006

TransMontaigne Inc.

TransMontaigne's Annual Evaluation Report
Integrity Management Program
CY 2006

Executive Summary

The following report is TransMontaigne's annual review of our Pipeline Integrity Management Program (IMP). TransMontaigne has developed a comprehensive pipeline integrity management program for maintaining the reliability and safety of its pipeline systems. The Integrity Management Program is intended to provide additional integrity to our identified high consequence areas. High consequence areas are those locations where a pipeline spill might have significant adverse impacts to areas of population, the environment, and/or commercial navigation. This annual evaluation report is mandated by US DOT 49 CFR Part 195.452 to assure that our Integrity Management Program is effective.

As of December 2006, TransMontaigne has completed 93.5% per cent of the scheduled baseline assessments. As a result of these assessments, a total of 87 anomalies were examined. In general, these anomalies were as expected, mostly external corrosion and/or third party damage. Internal corrosion issues were not identified. Investigation of the external corrosion indicated most were not active corrosion, supporting that the applied cathodic protection is adequate. Those external corrosion anomalies that appeared to be active corrosion were attributed to shielding of the protective current. Third party damage anomalies were investigated, and none appeared to be caused by recent unknown digging activities. Our present damage prevention program appears adequate for addressing this threat. Emergency flow restricting devices and our current leak detection system have been evaluated through a third party study, and recommendations from that report for additional mitigative measures have been considered and based on their recommendations no actions out of the ordinary are this time are warranted. There have been no leaks, injuries, or near misses to suggest that our present integrity management program is not effective.

Background

TransMontaigne is the operator of approximately 127 miles of jurisdictional hazardous liquid Category 2 (less than 500 miles) pipelines. These refined products pipelines are located in 6 states - Alabama, Arkansas, Mississippi, Missouri, Texas and Virginia. These pipeline assets have historically been managed and operated by TransMontaigne's engineering and operations group in Atlanta, Ga. **Table 1.0 – Pipeline Systems** identifies the jurisdictional pipeline systems operated by TransMontaigne subject to the Integrity Management Plan.

Table 1.0 Pipeline Systems

	System Name	Length (miles)	Age	Product Transported	State	Jurisdictional Status
	Razorback 8"	66.7	1989	Refined Products	AR	Interstate
	MB 10"	17.4	2000	Refined Products	TX	Interstate
	Collins 36" Line 9361	.88	1981	Refined Products	MS	Intrastate
	Collins 24" Line 600	.35	2002	Refined Products	MS	Intrastate
	Collins 36" (L8361)	.87	1981	Refined Products	MS	Intrastate
	Collins 8" Line 9081	.95	1973	Refined Products	MS	Intrastate
	Collins 18" Line 9181	.89	1973	Refined Products	MS	Intrastate
	Collins 24" Line 79	.41	1957	Refined Products	MS	Intrastate
	Collins 24" Line 78	.38	1957	Refined Products	MS	Intrastate
	Pinebelt 8"	34.22	1957	Refined Products	MS	Intrastate
	Bellmeade 8"	1.14	1999	Diesel Fuel	VA	Intrastate

1.0 HCA Identification

No changes or new HCA's have been noted based on field reports or NPMS updates.

2.0 Baseline Assessment Plan

Table 2.0 Initial Baseline Assessment Plan (BAP)

Rank	Segment Name	Length HCA (miles)	% Complete	Method of Assessment	Projected Assessment Date(CY)/Cost
[redacted]	Razorback 8”	29.50	100	C,G,HR MFL	Completed 2004
[redacted]	MB 10”	13.96	100	C,G,HR MFL	Completed 2006
[redacted]	Collins 36” Line 9361	0.82		ECDA	2007 ($25K)
[redacted]	Collins 24” Line 600	0.32		ECDA	2007 ($20K)
[redacted]	Collins 36” (L8361)	0.80		ECDA	2007 ($25K)
[redacted]	Collins 8” Line 9081	0.89		ECDA	2007 ($15K)
[redacted]	Collins 18” Line 9181	0.82		ECDA	2007 ($20K)
[redacted]	Collins 24” Line 79	0.41		ECDA	2007 ($20K)
[redacted]	Collins 14” Line 78	0.37		ECDA	2007 ($20K)
[redacted]	Pinebelt 8”	18.72	100	C,G,HR MFL	Completed 2006
[redacted]	Bellmeade 8”	1.14	100	C, HR MFL	Completed 2004
[redacted]	Total HCA Length	67.75			

Note: C – Clean, G – Geometric Tool, HR MFL – Hi Resolution Magnetic Flux Leakage Tool

Risk-Based Assessment Schedule

Note: Revised BAP under development for the next re-assessment interval.

3.0 Review of Assessment Results

A summary of the anomalies discovered as a result of the completed assessments are listed in Table 3.0 – Anomalies Discovered and Table 3.1 – Assessments Results by Cause.

Table 3.0 – Anomalies Discovered

Note any unexpected results & brief explanation. Ex. Metal loss (immediate repair) due to external corrosion and CP readings meet protective criteria.

ystem	Anomalies						
	Found Total	**Immediate**	**Immediate Repaired**	**60 Day**	**60 Day Repaired**	**180 Day**	**180 Day Repaired**
azorback 8" Completed 2004)	11	4	4	3	3	4	4
ЛB 10" Completed 2006)	0	0	0	0	0	0	0
ollins 36" Line 361	N/A						
ollins 24" Line 600	N/A						
ollins 36" (L8361)	N/A						
ollins 8" Line 9081	N/A						
ollins 18" Line 181	N/A						
ollins 24" Line 79	N/A						
ollins 14" Line 78	N/A						
inebelt 8" LI Run 10-06) - Repairs 1-07							
ellmeade 8" Completed 2004)	0	0	0	0	0	0	0

Table 3.1 - Assessments Results By Cause

Cause	Immediate	60 Day	180 Day
Third Party Damage (TPD)	0	0	0
Construction Related (CR)	4	3	4
External Corrosion (EC)	0	0	0
Internal Corrosion (IC)	0	0	0
Manufacturing Defect (MD)	0	0	0
Equipment Failure (EF)	0	0	0
Incorrect Operations (IO)	0	0	0
Stress Corrosion Cracking (SCC)	0	0	0
Outside Natural Force (ONF)	0	0	0

4.0 Preventive and Mitigative Measures

Table 4.0 – Preventive & Mitigative Measure Summary

Recommended Preventive & Mitigative Measures										
	System Name	Recommended P&M Measures (Y/N)								
		TPD	CR	EC	IC	MD	EF	IO	SCC	ONF
	Razorback 8"	N	N	N	N	N	N	N	N	N
	MB 10"	Y	Y	Y	Y	Y	N	N	N	N
	Collins 36" Line 9361	N	N	N	N	N	N	N	N	N
	Collins 24" Line 600	N	N	N	N	N	N	N	N	N
	Collins 36" (L8361)	N	N	N	N	N	N	N	N	N
	Collins 8" Line 9081	N	N	N	N	N	N	N	N	N
	Collins 18" Line 9181	N	N	N	N	N	N	N	N	N
	Collins 24" Line 79	N	N	N	N	N	N	N	N	N
	Collins 14" Line 78	N	N	N	N	N	N	N	N	N
	Pinebelt 8"	Y	Y	Y	Y	Y	N	N	N	N
	Bellmeade 8"	N	N	Y	N	N	N	N	N	N

Where a Y (Yes) response is indicated in the table above – Explain ex. Razorback TPD = Y – decrease patrolling frequency/install additional line markers (have been completed, scheduled, or under consideration). Also include any improvements that you can take credit for ex. Coating rehab, depth of survey study, the facilities P&MM study, GIS survey, etc.

Pinebelt – ILI, Caliper, GPS, CIS surveys completed.

MB- ILI< Caliper, GPS, CIS surveys completed.

5.0 Performance Measures

TransMontaigne Partners, Limited Liquid Product Pipelines

Performance Measure Attribute	2005	2006	Comments
Total pipeline miles and pipeline miles that could potentially affect HCAs;	127/67.75	127/67.75	Pinebelt, MB Pipeline Assessed
Total pipeline miles assessed;	0	52.7	Pinebelt 34.7 – MB 18
Pipeline miles assessed by different assessment methods (i.e., different types of in-line inspection devices (or smart pigs), hydrostatic pressure testing, or direct assessment or other methodologies)	0	52.7	34.7 Geometry 34.7 MFL 18 Geometry 18 MFL
Actions taken to address anomalies identified during in-line inspections	0	17	
Pipeline miles assessed by hydrostatic pressure testing;	0	0	
Defects identified through hydrostatic pressure testing and direct assessment	0	0	
Pipeline miles assessed by other techniques;	0	0	
Actions taken to address anomalies identified through other assessment techniques.	0	0	
No of Leaks	0	0	
No of Leaks over 5 bbl	0	0	
No of Leaks over 50 bbl	0	0	

Add any additional measures being tracked. Explain in Comments column any negative trends.