CERTIFIED MAIL – RETURN RECEIPT REQUESTED

Shell Pipeline Company LP
Two Shell Plaza
P.O. Box 2648
Houston, TX 77002

April 28, 2008

U.S. Department of Transportation
Pipeline and Hazardous Material Safety Administration
Mr. R. M. Seeley
Director, Southwest Region
8701 South Gessner Road, Suite 1110
Houston, TX 77074

SUBJECT: NOTICE OF AMENDMENT, CPF No. 4-2008-5009M

Dear Mr. Seeley,

Representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) conducted an inspection of Shell Pipeline Company's (SPLC) Integrity Management Program on July 9-13 and 23-27, 2007.

On April 2, 2008 SPLC received a Notice of Amendment, dated March 28, 2008, outlining apparent inadequacies found within SPLC plans or procedures noted during the inspection. This letter serves as a response to the Notice and is being submitted to PHMSA within the required 30 days of receipt of the Notice.

The Notice identified four apparent inadequacies found within SPLC plans or procedures. While SPLC disagrees that these issues represent inadequacies in its IMP program, we are committed to continually improving our IMP and addressing PHMSA's evolving expectations. Therefore, we have updated the program documentation to address the points identified in the NOA.

Below is an explanation of how each item in the NOA was addressed. The revised pages from the program have been attached. Additionally, the directly applicable text has been highlighted, boxed and labeled.

1. **§195.452 Pipeline integrity management in high consequence areas.**
   (f) An operator must include, at minimum, each of the following elements in its written integrity management program:
   (1) A process for identifying which pipeline segments could affect a high consequence area.

   PHMSA Finding:
   Shell must modify their process for calculating release volumes to consider the effects of additional inventory from tanks and other potential sources in the vicinity of potential pipeline rupture locations. There may be locations in which additional inventory could increase predicted spill volumes including other potential sources, such as injection points and connections to other pipelines. Shell must also consider small leak spill volume scenarios below SCADA detection thresholds used in release volume calculations, including hole size, pressure, equipment type, operator response times, and drain down volume. It is possible for some segments that these small leak scenarios could result in larger projected spill volumes than for large break scenarios.

SPLC Response:
SPLC is modifying the Integrity Management Program to include consideration of tanks, injection/connection points and a small leak scenario in calculating potential release volume from conventional liquid pipelines for use in identifying pipeline segments that could affect a high consequence area. SPLC is making revisions to Sections 2.3.1, Appendix B and Appendix D of the IMP to incorporate these changes. Attached are excerpts from the affected sections of the IMP that will be included in the next IMP revision, planned for June of this year. Any change in calculated volumes and overland spread as a result of this modification will be reviewed as part of the continual assessment for each of our pipelines.

2. **§195.452 Pipeline integrity management in high consequence areas.**
(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:
(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.
(c) What must be in the baseline assessment plan?
(1) An operator must include each of the following elements in its written baseline assessment plan:
(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;
(B) Pressure test conducted in accordance with subpart E of this part;
(C) External corrosion direct assessment in accordance with §195.588; or
(D) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section… (iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

PHMSA Finding:
Shell must modify the seam failure susceptibility criteria flow chart in Appendix F; page F-5 of their IMP manual. This chart differs from the expanded approach recommended in the Baker/Kiefner report TTO-05 (section 9) and could result in the false justification that pre-70 LF ERW or lap-welded pipe is not susceptible to seam integrity issues.

SPLC Response:
SPLC has revised the flow chart in Appendix F of the IMP to align with the latest revision (April 2004) of the Baker/Kiefner report. A copy of the revised flow chart is attached. This revision will be included in the next IMP revision, planned for June of this year. A review of applicable line segments has determined that no lines had been falsely justified as not susceptible to seam integrity issues as a result of the table that was used in the previous revision of the Integrity Management Program.

3. **§195.452 Pipeline integrity management in high consequence areas.**
(f) ***see above***
(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section)

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

(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
(2) Data gathered through the integrity assessment required under this section;
(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and
(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

PHMSA Finding:
Shell must modify the process for identifying anomalies from ILI results to account for tool tolerance or provide adequate justification and documentation of how tool tolerance is treated. Shell stated they believe the "totality" of their process will adequately address tool tolerance questions and results are evaluated and documented with the Integrity Assessment Database Report, Unity Plot, and Final Integrity Report "Validating ILI Tool Run" section. The current procedure does not adequately account for tool uncertainties and may lead to situations in which response to immediate repair conditions is delayed.

SPLC Response:
SPLC continues to believe that our overall process, which incorporates the Anomaly Response Table to summarize required responses and timing for anomalous conditions found during an ILI, a Unity Plot of actual vs. reported conditions, periodic review of the performance of our ILI vendors, Data Integration Meetings wherein results of the ILI are reviewed by personnel with expertise in ILI inspections as well as personnel with knowledge of the pipeline being inspected, the Integrity Assessment Database, and the Final Integrity Report, addresses tool tolerance issues.

However, since some of these activities occur later in the overall process, we agree that some additional consideration can be given to ILI tool tolerance in identifying immediate conditions. We have therefore revised the Anomaly Response Table, copy attached, to address this issue. The revised table will be included in the next IMP revision, planned for June of this year.

4. **§195.452 Pipeline integrity management in high consequence areas.**
(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?

(f) ***see above***

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

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

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

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

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
(ii) Elevation profile;
(iii) Characteristics of the product transported;
(iv) Amount of product that could be released;
(v) Possibility of a spillage in a farm field following the drain tile into a waterway;
(vi) Ditches along side a roadway the pipeline crosses;
(vii) Physical support of the pipeline segment such as by a cable suspension bridge;
(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure

PHMSA Finding:
Shell must modify the risk scorecard question in their IMP manual, specifically OF-15 (outside force damage) to include hurricanes as natural force threat. Shell does not list hurricanes as a significant threat to pipelines and must continually evaluate operator specific and industry leak/failure history to derive lessons learned that can be applied to their risk assessments.

SPLC Response:
The risk scorecard question, OF-15, has been modified to specifically include hurricanes as a natural force threat. A copy of the revised scorecard is attached and will be included in the next revision of the IMP, scheduled for June of this year. SPLC has always considered hurricanes when reviewing risks to pipelines in the Gulf of Mexico or vicinity. Hurricanes have always been a specific listed likelihood threat on our Risk Assessment Data Sheets, a graphic data integration tool used in our Risk Assessment Meetings.

SPLC continues to aggressively learn from industry incidents as well as from its own. The company is actively involved in many industry organizations, including API, AOPL, and PRCI, that provide numerous networking opportunities, newsletters, and other publications that present the best available information for learning from pipeline industry events. SPLC currently chairs the API Pipeline Integrity Committee. As required by our IMP, SPLC also participates in the API Pipeline Performance Tracking System and its Data Mining Team. This important team exists solely to analyze industry leak/failure history and issue advisories based on that analysis. Learnings from this team and the other sources are used to update our IMP and our technical advisories, the tool used to broadly communicate industry incident learnings as part of our continual risk assessment process.

At this point, I believe that SPLC has addressed all of the items in the NOA with the proposed revisions. In the event that you believe the proposed revisions do not adequately address the items, we reserve our right to a hearing on all issues outlined in the Notice. In the event that such a hearing is required, SPLC does not plan to be represented by council.

As requested in the NOA, we are also sending an electronic version of this response via e-mail. Please contact me at 713-241-3620 if you have any questions or wish to discuss the items above further.

Sincerely,

Brian Sitterly

Brian Sitterly
Manager, Integrity & Regulatory Services

Attachments

2.3.1 - Conventional Liquids in Onshore Pipelines

For conventional liquids transported through onshore pipelines, i.e. liquids that remain liquid at atmospheric conditions (e.g. crude oil, gasoline, jet fuel, diesel, etc.), the following pipeline segments shall be considered HCA segments, unless it can be demonstrated through a more detailed analysis, as described above, that the segment cannot affect the HCA:

1. All pipeline segments that intersect an HCA.
2. All pipeline segments for which overland spread modeling predicts that a release could potentially reach an HCA. Two software tools are generally used for this analysis as follows:

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- **The Company's Spill Model should be used to model the estimated release volume for use in overland spread modeling.** Spill Model is a proprietary software program that calculates potential spill volume for a liquid pipeline and considers volume pumped out during the time to detect the release, shutdown pumps and close valves, as well as drain down volume after the pipeline is shutdown. **It considers the scenario of a full line rupture as well as the scenario of a smaller volume release that could go undetected for a longer time.** The program selects the largest release volume calculated basis the two scenarios as the worst-case release volume for input to the overland spread model. **Where tanks are located on the pipeline, the program can accommodate the additional volume which may be released due to the inventory in the tank. Injection/connection points to other pipelines are addressed by dividing a line into separate segments at the connection points..**

*Additional information on the Company's Spill Model Program is provided in **Appendix D, Models to Aid in HCA Identification**.*

- An overland spread model, which is a GIS based model, should be used to predict the surface liquid spread after a release from a liquids pipeline. The area (plume) covered by a potential release is modeled based on the volume of liquid that would pump/drain out of the pipeline at various points along the system.

  Overland spread modeling should be conducted using a model that provides both terrestrial and hydrological modeling, i.e. it models both the spread of liquid over land, considering the local topography and surface characteristics, and models transport of liquids should the release volume reach water, e.g. streams, rivers, etc.

Additional information on the Overland Spread Model is provided in ***Appendix D, Models to Aid in HCA Identification.***

Conventional available overland spread models do not provide a reasonable prediction of surface spread in areas that are flat and contain extensive surface water, such as in areas of southern Louisiana. In these areas, the improved "No Wetlands" version of overland spread modeling should be used. This version of overland spread filters out wetlands while maintaining the NHD and lake portion of water bodies. This filtering avoids the extensive plume results over wetlands, something we know from experience does not happen.

Unless more detailed criteria are developed for the specific pipeline being modeled, the following criteria should be used for spill and overland spread modeling:

- Spill points for calculation of potential release volumes and modeling overland spread located at the following points:
    - 500-foot intervals along the pipeline

      Company has found that 500-foot intervals in combination with spillpoints at waterway crossings provide adequate coverage in the overland spread model. See PIA section of ***Appendix D, Models to Aid in HCA Identification*** *for more information.*
    - Commercially navigable waterway crossings
    - National Hydrologic Dataset (NHD) waterway crossings
    - Facilities on the pipeline, e.g. pump stations, meter sites, terminals
    - Emergency Flow Restricting Devices (EFRD) along the pipeline (mainline block valves and check valves)
- Flow rate – maximum installed capacity
- Response time
    - Full line rupture scenario
        - Lines monitored from the Control Center (CC) – six minute response time to detect a release and initiate shutdown and valve closure

- Lines not monitored from the CC – varies by system and location and should be determined considering level of local monitoring and patrol; location of line; and pipeline operating conditions, such as pressure, flow, shutdown ~~capability, etc~~

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- **Small release scenario**
  - **Lines monitored from the CC – Response time of 12 hours at a release rate equal to the CC Line Balance Alert level setting (setting below which Controller will not be alerted to a possible release)**
  - **Lines not monitored from the CC - varies by system and location and should be determined considering level of local monitoring and patrol; location of line; and pipeline operating conditions, such as pressure, flow, shutdown capability, etc**

- **Tank assumptions for locations where release volumes could be affected by tank inventory – Volume based on largest tank at the location, elevation based on elevation of tank maximum level**
- Remote block valve closure time - five minutes
- Manual block valve closure time – varies by system and location
- Emergency response time for personnel to stop/impede water transport - 12 hours
- Residual thickness of product remaining on surface – ¼ inch
- Buffer at NHD features – 300 ft. each side

3. Additional HCA segments may be identified through a review by local operating, maintenance and/or other personnel familiar with the pipeline and its surroundings. This may be accomplished during formal Risk Assessment Meetings (see Section 3 and **Appendix B**) or through other meetings/discussions specifically arranged for these reviews. A number of factors should be considered during these reviews, including:

- Operating conditions, e.g. flow rate, pressure, etc.;
- Commodity transported and its characteristics;
- Past release history of the pipeline, including release impact;
- Spill model results;

- General overview of risk and associated definitions (see **Section 3.0,** of the IMP
- Risk assessment background and development within the Company
- Process overview
- RAM objective
- Distribute RADS Legend and the Risk Ranking Matrix
- Review assessment support tools, meaning of information, how it is displayed and how it is used in the meeting. Basic tools and their content to review are:
  - RADS/System Maps/TRAMs
  - Pipeline alignment drawings (typically 1:100K & 1:24K)
  - Pipeline alignment data layers (topographic, water, roads, cultural and HCA)
  - RADS Legend (see **Attachment B.1**)
  - Checklists (consequence and likelihood)
  - Risk Ranking Matrix
  - Haz-It documentation software
- Integrity Management Rule overview, impact on meeting and how information is displayed on support tools
- Industry Bulletins and Advisories
- Scope of specific assessment
- Review Risk Screening Scorecard for RAM specific asset
- Review Past RAM items, MOCs and release history for specific asset
- Operations Overview (provided by region operations SME)

The activities listed above are applicable to Pipeline and Terminal RAMs.

B.4.3.4 - Potential Release Impact

The objective of this part of the meeting is to review how a release may impact the area adjacent to the pipeline or facility. The most credible worst-case scenarios are considered. Key points and applicable assumptions to be reviewed are:

- Release history

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- **Company Spill Model results if conventional liquid. Assumptions are outlined in IMP Section 2.3.1**

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- Overland Spread model results if conventional liquid. Assumptions:
  - **Spill Volume calculated using Shell Spill Model considering both full line rupture and a small volume release. The largest volume calculated basis the two scenerios should be used.**
  - No absorption into ground
  - Released commodity is ¼ inch deep
- Dispersion Model Results if HVL. Assumptions:
  - Maximum Flow Rate/Pressure Conditions
  - Full line rupture/2" hole/1/4" hole
- For Conventional liquids, Spill and Overland Spread data as well as buffers displayed on RADS/System Maps and how they are to be used in the meeting. Buffers are included primarily as an aid in gaining a perspective on distances from the pipeline. Buffer size (miles each side of the pipeline) vary based on pipeline diameter as follows:
  - 8" = ¼
  - 8 to <20 = ½
  - 20 to <36 = ¾
  - ≥ 36 = 1
- For HVLs, impact zones (buffers) determined basis the dispersion analysis conducted during HCA segment identification displayed on RADS/System Maps and how they are to be used in the meeting. Alignment scale (1" = 50,000", etc.)
- Pipeline elevations/profile (**red** numbers = alignment numbers & **green** numbers = survey equations)
- Release history and how it compares to spill model/overland spread or dispersion model predicted results
- Drain time for conventional liquid spills or dispersion time for HVLs
- Drain direction and distance (conventional liquids) or dispersion distance and elevation (HVLs) from release point

B.4.3.5 - Consequence Assessment

Consequence refers to the impact an event might have if it occurs. The activities to be addressed during this portion of the risk assessment are two fold. The first activity is to review and validate the displayed consequence information and to identify additional areas of consequence (based on knowledge of local SMEs) that may not be indicated. The

SPILL MODEL PROGRAM OVERVIEW

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The **Company's Spill Model** is a proprietary software program which calculates potential spill volume for a liquid pipeline and considers volume pumped out during the time to detect the release, shutdown pumps and close valves, as well as drain down volume after the pipeline is shutdown. **It considers the scenario of a full line rupture, assuming a completely severed pipeline, as well as the scenario of a smaller volume release that could go undetected for a longer time.** The program selects the largest release volume calculated basis the two scenarios as the final estimated release volume.

The program can also consider effects on release volume from tanks and injection points or other pipeline connections located on the pipeline. Tank volumes are simulated by adding an equivalent length of pipe, with a volume equal to the volume of the largest tank, to the pipeline at the location of the tank. Injection points or other pipeline connections are considered by dividing the pipeline into segments at the injection/connection point and running models of each individual segment.

The Spill Model program has been used by the Company since 1986 and has been a valuable tool in developing worst-case release scenarios for the Company's Facility Response Plans (FRPs). Recently, the Spill Model has been used extensively in the Pipeline Risk Assessments process to assist in identification of pipeline segments that could affect an HCA. The user can calculate the potential release volumes for up to 7500 points (nodes) along the length of a pipeline, review graphical results, and then modify the input to determine the effect on the resulting release potential.

A pipeline segment is modeled as a series of elevation-distance points called nodes. Nodes are used to describe points on the pipeline segment such as a no-device elevation point, a block valve, or a check valve. The program calculates the potential release volume at each node.

Input Parameters

Input parameters to the Spill Model include:

- Pipeline profile, including beginning and ending points and elevation points along the length of the profile (up to 7,500 nodes);
- Block valve and check valve locations;
- Block valve closure times (remote and/or hand operated);
- Maximum pipeline flow rate;
- Specific gravity and viscosity of fluid in the pipeline;
- Response time to detect the release and shut down the pumps on the pipeline for a full line rupture scenario;

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- **Release rate and response time to detect the release and shut down the pumps on the pipeline for a small volume release scenario**, and;

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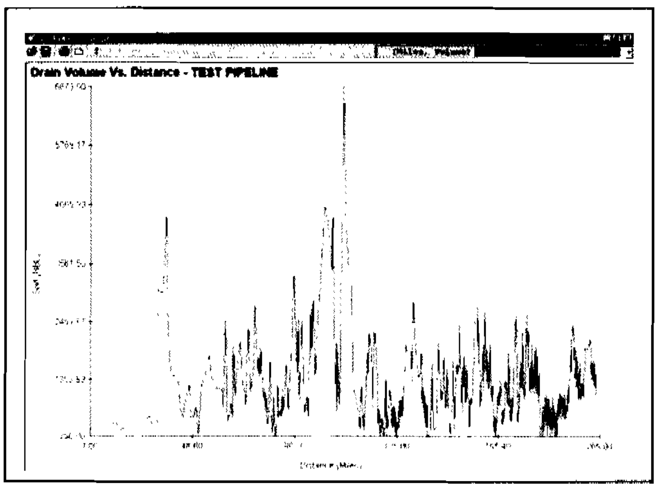
- **Tank information (if applicable), including volume of the largest tank at the location and elevation of the maximum operating level of the tank**

Output generated from the model includes:

- Potential release volume for up to 7,500 nodes on the pipeline (largest volume calculated basis the full line rupture and small release scenarios);
- Corresponding drain time for the potential release volume at each node;
- A graphical display of the pipeline profile (distance in miles vs. pipeline elevation in feet);
- A graphical display of the potential release volume results (distance in miles vs. spill volume in barrels), and;
- A graphical display of corresponding drain time along the length of the pipeline (distance in miles vs. drain time in hours).

Below is a sample output chart from the Spill Model program. The chart shows distance (miles) vs. drain volume.

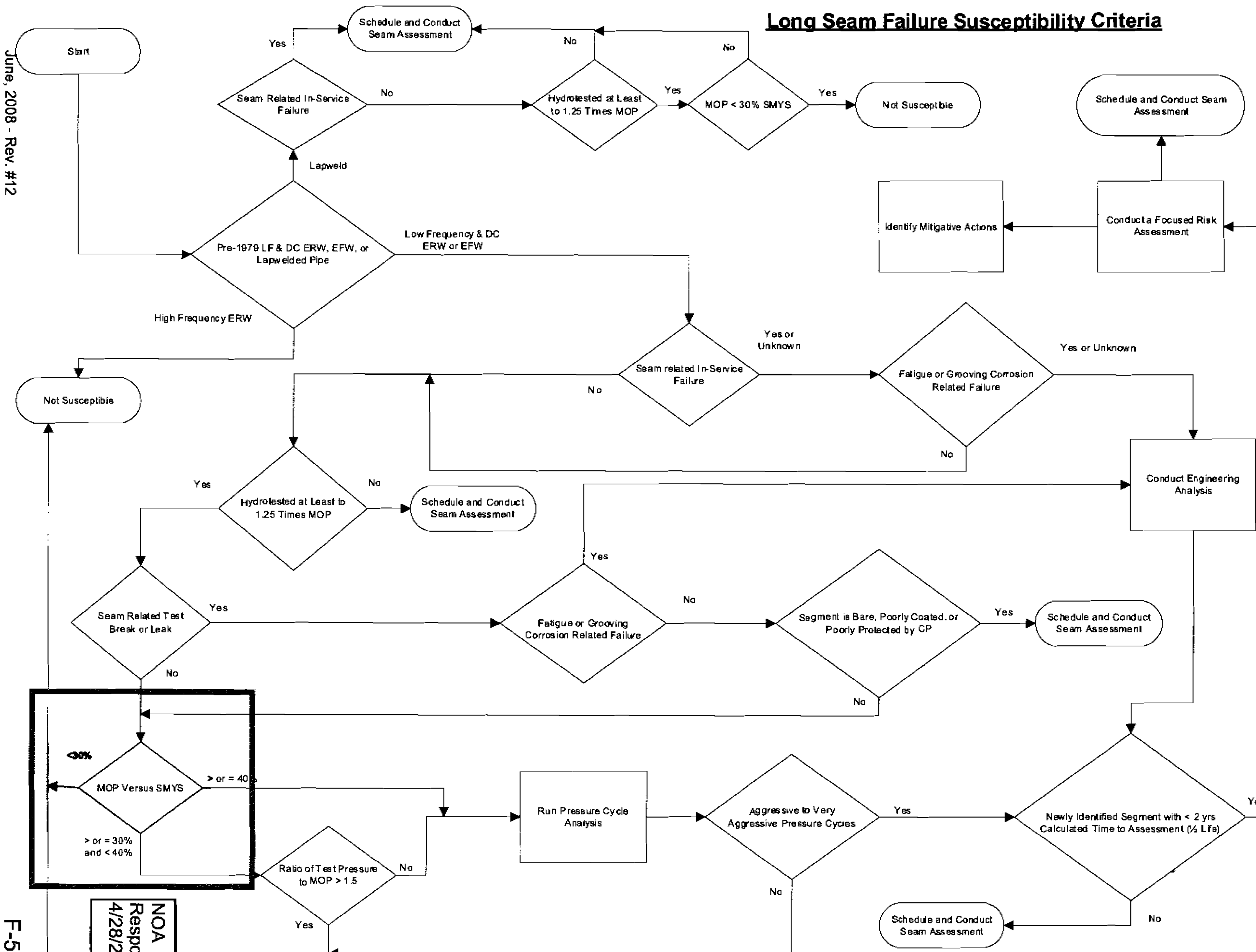


Uses of Spill Model include:

- Calculate "worst case" release scenarios for Facility Response Plans;
- Calculate potential release volume reduction of adding EFRDs (check valves, block valves, or remoting existing valves), and;
- Spill Model output is used as input to "Overland Spread" calculations in GIS.

The Spill Model program consists of three parts: 1) An Excel spreadsheet which is used to create/modify the pipeline profile and physical properties of the liquid; 2) A Visual Basic program which reads the Excel data, requests pipeline flow rate and shutdown

Long Seam Failure Susceptibility Criteria



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ANOMALY RESPONSE TABLE FOR HAZARDOUS LIQUID PIPELINES

This "Anomaly Response Table" and associated footnotes summarize Shell Pipeline's required response and timing from discovery for certain conditions that may be discovered as a result of In-Line inspection. Alternative responses and timing require use of the "Notification Form" and approval from the Region Manager, Manager Operations Support & Engineering, and Manager, Asset Integrity.

IMMEDIATE CONDITIONS

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DESCRIPTION	COULD AFFECT HCA SEGMENTS PHMSA USDOT 195.452		OTHER SEGMENTS (9)	
	RESPONSE (11)	MAXIMUM TIME FROM DISCOVERY (6)	RESPONSE (11)	MAXIMUM TIME FROM DISCOVERY (6)
IMMEDIATE CONDITIONS (GROUP 1) (12)				
a. Metal Loss >70% (13)	Shutdown (7) or 20% pressure reduction with approval (2) (8)	Immediate but not to exceed 48 hours	Shutdown (7), 20% pressure reduction (2) (8), on-site monitoring, leak test, or other mitigative actions	Immediate but not to exceed 5 days
	Repair	Before returning to normal operating pressure or restarting.	Repair	Before restart, returning to normal operating pressure or discontinuing mitigative actions
b. P_{burst} < 110% MOP (13)	Shutdown (7) or reduce pressure ≤ P_{safe} (4) (8)	Immediate but not to exceed 48 hours	Shutdown (7), reduce pressure ≤ P_{safe} (4) (8), on-site monitoring, leak test, or other mitigative actions	Immediate but not to exceed 5 days
	Repair	Before returning to normal operating pressure or restarting.	Repair	Before restart, returning to normal operating pressure or discontinuing mitigative actions
c. Top Side Dent (1) with Metal Loss, cracking, or stress riser	Shutdown (7) or 20% pressure reduction with approval (2) (8)	Immediate but not to exceed 48 hours	Shutdown (7), 20% pressure reduction (2) (8), on-site monitoring, leak test, or other mitigative actions	Immediate but not to exceed 5 days
	Repair	Before returning to normal operating pressure or restarting.	Repair	Before restart, returning to normal operating pressure or discontinuing mitigative actions
d. Top Side Dent (1) >6%	Shutdown (7) or 20% pressure reduction with approval (2) (8)	Immediate but not to exceed 48 hours	Repair	180 days (Ref. API 1160, First Edition, Section 9.6)
	Repair	Before returning to normal operating pressure or restarting		
e. Judgment of Operator (3)	Shutdown (7), reduce pressure ≤ P_{safe} (4) (8) or other mitigative actions	Immediate but not to exceed 48 hours	Shutdown (7), reduce pressure ≤ P_{safe} (4) (8), on-site monitoring, leak test, or other mitigative actions	Immediate but not to exceed 5 days
	Repair	Before returning to normal operating pressure or restart.	Repair	Before restart, returning to normal operating pressure or discontinuing mitigative actions

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Anomaly Response Table

ANOMALY RESPONSE TABLE
FOR HAZARDOUS LIQUID PIPELINES (Cont'd)

60 DAY, 180 DAY, and 365 DAY CONDITIONS

DESCRIPTION	COULD AFFECT HCA SEGMENTS PHMSA USDOT 195.452		OTHER SEGMENTS (9)	
	RESPONSE (8)(11)	MAXIMUM TIME FROM DISCOVERY (6)	RESPONSE (8)(11)	MAXIMUM TIME FROM DISCOVERY (6)
60 DAY CONDITIONS (GROUP 2)				
a.1 PIPE DIAMETER ≥ 12" Top Side Dent (1) >3%	Evaluate & Remediate	60 days	Evaluate & Remediate	365 days
a.2 PIPE DIAMETER < 12" Top Side Dent (1) ≥ 0.25"	Evaluate & Remediate	60 days	Evaluate & Remediate	365 days
b. Bottom Side Dent (1) with metal loss, cracking or stress riser	Evaluate & Remediate	60 days	Evaluate & Remediate	365 days
180 DAY CONDITIONS (GROUP 3)				
a.1 PIPE DIAMETER ≥ 12" Dent >2% that affects curvature of pipe at a girth weld or at a longitudinal seam weld.	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
a.2 PIPE DIAMETER < 12" Dent ≥ 0.25" that affects curvature of pipe at a girth weld or at a longitudinal seam weld.	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
b. PIPE DIAMETER ≥ 12" Top side Dent (1) >2%	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
c. Bottom Side Dent (1) >6%	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
d. P_{safe} < MOP	Evaluate & Remediate (12)	180 days	Evaluate & Remediate (12)	365 days
e. An area of general corrosion with predicted Metal Loss >50% (width >2/3 of the circumference for a length > 1 pipe joint)	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
f.1 Metal Loss >50% at foreign line crossings	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
f.2 Metal Loss >50% in area with widespread circumferential corrosion (width >2/3 of the circumference)	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
f.3 Metal Loss >50% in an area that could affect a girth weld, within the HAZ of the weld. (5)	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
g. Potential cracks (10)	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
h. Corrosion of or along a pipe longitudinal seam weld (5)	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days
i. Gouge or groove >12.5% of pipe wall thickness	Evaluate & Remediate	180 days	Evaluate & Remediate	365 days

ANOMALY RESPONSE TABLE FOR HAZARDOUS LIQUID PIPELINES (Cont'd)

Notifications

The use of the "Notification Form" in Volume 1, Appendix J is required to:

- Communicate to management that the response and timing requirements of the table cannot be met.
- Gain approval for alternative responses and/or timing

The "Notification Form" shall be completed with all required approvals prior to implementation of alternative responses and/or timing or as soon as it becomes evident that the required response/timing cannot be met. For HCA Segments, the Office of Pipeline Safety (OPS) must be notified if the timing requirements of the table cannot be met and safety cannot be provided through a pressure reduction. Notifications to OPS will be made by the Manager, Integrity & Regulatory Services or designated alternate.

Footnotes:

(1) Top Side defined as at or above 4 & 8 o'clock position and Bottom Side defined as below 4 & 8 o'clock position.

(2) Pressure level identified as documented (e.g. Control Center records, chart recorders) historical high pressure (4 hour minimum duration) to have occurred within the past six months since In-Line Inspection tool removal.

(3) Judgement of the person(s) designated by the Operator to evaluate the integrity assessment results i.e. the qualified person(s) as described in 49 CFR 195.452 who have met the requirements of section 5.3.4 of Volume 1 SPLC's Integrity Management Program. ILI tool tolerance shall be considered in the evaluation.

(4) Pressure reduction at the location of the anomaly considering surge and dead-head conditions. P_{safe} shall be calculated using either B31G or Modified B31G.

(5) Refer to ASME B31.4-2006 451.6.2.2 (e) Grooving, Selective, or Preferential Corrosion of Welds. Grooving, selective, or preferential corrosion of the longitudinal seam on any pipe manufactured by the electric resistance welding (ERW) process, electric induction welding process, or electric flash welding process shall be removed or repaired. Reference SPLC Pipeline Inspection and Maintenance Manual Section 3.11.12 Pipeline Repairs-Additional Guidance and Information.

(6) 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. **Immediate conditions are considered discovered** no later than 72 hours following receipt of an In-Line-Inspection Preliminary or Final Report by the qualified person(s). For immediate conditions on segments that can impact an HCA, the required response must be taken within 48 hours of discovery. The required response must be taken within 5 days of discovery for immediate conditions on "other segments".

(7) Where shutdown is indicated as the required response, the intent is to maximize safety until the anomaly can be evaluated and remediated. There may be circumstances where a shutdown of the pipeline may not be prudent to maximize safety. Static head calculations should be performed to determine the static pressure in the pipeline at the anomaly, so as not to exceed P_{safe} (it is possible, at lower elevations, to have a higher pressure under shutdown conditions). Where shutdown is required on an HVL pipeline, maintaining the pipeline pressure above the products vapor pressure may maximize safety by allowing continued monitoring of line integrity while the pipeline is shutdown.

(8) A pressure reduction (to max of P_{safe} if remaining strength can be calculated, 20% reduction for other anomalies – see footnotes (2) and (4) above) is an acceptable anomaly response if taken within the identified response timing. A pressure reduction, in response to an anomaly on a segment that can affect an HCA, cannot exceed 365 days without taking further remedial action to insure the safety of the pipeline, including documenting a technical justification to demonstrate the integrity of the pipeline will not be jeopardized. Pressure reduction as a response requires use of the SPLC Management of Change (MOC) process.

(9) Offshore Pipelines – The response and timing requirements in this table do not apply to offshore pipeline segments that cannot impact high consequence areas. Plans for evaluating anomalies on offshore pipeline segments that cannot impact high consequence areas will be developed on a case-by-case basis with approval by the Region Technical Manager and Manager Integrity & Regulatory Services.

(10) Potential cracks refer to inline inspection (ILI) tools not designed to detect cracks, i.e. metal loss and deformation tools. When performing inline inspection by ultrasonic crack detection tools or circumferential magnetic flux leakage tools, project specific response criteria shall be established.

(11) If the anomaly remediation method is pipeline repair, reference SPLC Pipeline Inspection and Maintenance Manual Section 3.11.7 Pipeline Repairs-Allowable Repairs for allowable pipeline repair options.

(12) For immediate conditions and Psafe conditions, temporary pressure reduction should be taken during excavation, inspection/evaluation, and repair activities as a personnel safety measure. Reference Section 3.11.1 in the Pipeline Inspection and Maintenance Manual. A Work Authorization Permit may be used to communicate temporary pressure reduction requirements to the Control Center.

(13) An allowance to account for ILI tool tolerance has been included in the criteria for these anomalies.

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Anomaly Response Table

PIPELINE RISK SCREENING - SCORECARD

DATA ENTRY SPREADSHEET

System Name				
PIP Focal Point				
Type of Pipeline				
Date Completed/Updated		dd-mmmm-yyyy		
Consequence Score		**14880**	**(Points)**	
Probability Score		**22.29**	**(%)**	
Normalized Risk Score		**195.11**	**(Points/km)**	**Comments**
Cause - Outside Force Damage				
	Weighting Units		**Response**	
OF-1	5	Has the pipeline had any releases due to Outside Force Damage (OFD) in the last 5 years?	NO	**(YES or NO)**
OF-2	2	Has the pipeline received any damage caused by OFD in the last 5 years?	NO	**(YES or NO)**
OF-3	4	Has the pipeline been damaged more than once by OFD in the last 5 years?	NO	**(YES or NO)**
OF-4	10	What percentage of the pipeline length has experienced significant encroachment onto the pipeline Right-of-Way by high risk developments that has not been properly reviewed and/or made less severe by appropriate mitigation efforts?	15	**(%)**
OF-5	8	What percentage of the pipeline length has been inspected with a geometry or caliper In Line Inspection tool to detect outside force damage in the last 5 years?	100	**(%)**
OF-6	3	What percentage of the pipeline Right-of-Way cannot be visually inspected because it is overgrown, developed or cannot be traversed?	0	**(%)**
OF-7	3	What percentage of the pipeline Right-of-Way is properly marked to indicate the presence of a pipeline?	100	**(%)**
OF-8	6	What percentage of the pipeline Right-of-Way is located in an area where the local One-Call system functions properly?	100	**(%)**
OF-9	7	What percentage of the requests received to locate and mark the pipeline are responded to?	90	**(%)**
OF-10	3	What percent of the requests received to locate and mark the pipeline are conducted by non-company personnel?	50	**(%)**
OF-11	6	What percent of the excavation activities along the pipeline ROW are observed by qualified company personnel or representative?	100	**(%)**
OF-12	5	What percent of the pipeline Right-of-Way has been inspected for sections of exposed pipe in the past 2 years?	0	**(%)**
OF-13	5	What percent of the graded areas along pipeline Rights-of-Way have been inspected to determine the depth of cover in the past 2 years?	0	**(%)**

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OF-14	5	What percent of the pipeline Right-of-Way has been inspected to determine the depth of cover in the past 3 years?	100	(%)
OF-15	6	What percent of the pipeline Right-of-Way is located in an area subject to hurricanes (tropical cyclone), flooding, earthquakes, landslides, mining, etc?	100	(%)
OF-16	8	What percent of the pipeline Right-of-Way is covered by a Community Awareness or Damage Prevention plan in place?	100	(%)
OF-17	4	What percentage of the landowners and tenants living and/or working along the pipeline Right-of-Way has the operator communicated with regarding pipeline safety in the last 3 years?	0	(%)
OF-18	4	What percentage of local excavation contractors and emergency response agencies has the operator met with to discuss pipeline safety in the last year?	0	(%)
OF-19	4	Are there above ground piping/facilities near high-risk areas without protective measures (traffic barriers, fencing)?	YES	(YES or NO)
OF-20	2	Are there roads crossing over the mainline that were constructed without appropriate design review?	NO	(YES or NO)
	(100)			
Cause Index Score (38%)			**12.05**	**(%)**

Cause - Corrosion

	Weighting Units		Response	
CR-1	15	Has the pipeline had a release due to corrosion in the last five (5) years?	NO	(YES or NO)
CR-2	5	What percentage of the pipeline length has had a history of not meeting a polarized potential criteria **and** has not been evaluated by a smart pig or a hydrostatic test since it has been upgraded to meet the criteria?	0	(%)
CR-3	10	What percentage of the pipeline length has had a Close Interval Potential Survey (CIPS) in the last 10 years using a polarized potential criteria **and** has a documented resolution to address the identified areas that did not meet the minimum criteria?	0	(%)
CR-4	5	What percentage of the pipeline length does not have a corrosion protection coating (bare pipe)?	0	(%)
CR-5	5	What percentage of the pipeline length operates at a temperature equal to, or greater than, 120° F (49°C)	0	(%)
CR-6	10	What percentage of the pipeline length routinely operates at a flow rate below the velocity required to remove water **or** only operates 90% of the time or less?	0	(%)
CR-7	10	What percentage of the ILI tool identified external corrosion defects (of any depth) were inspected on a pipeline that has a coating known to shield cathodic protection currents?	0	(%)