CITGO Petroleum Corporation

P O Box 4689
Houston, TX 77210-4689

August 26, 2008

CERETIFIED MAIL – RETURN RECEIPT REQUESTED

Mr. R.M. Seely
Direcotr, Southwest Region
Pipeline and Hazardous
Materials and Safety Administration
8701 South Gessner, Suite 1110
Houston, TX 77074

RE: CITGO IMP NOTICE OF AMENDMENT LETTER
CPF 4-2008-5012M

Dear Mr. Seely,

As previously agreed, CITGO is providing you with informaiton and amended procedures to address NOA Items 6 – 10 identified in your letter of April 28, 2008.

If I can be of further assitance in this matter please do not hesitate to contact me.

Sincerely,

Kent Powers
General Manager
Terminal Facilities and Pipelines

CITGO Petroleum Corporation
INTEROFFICE LETTER

August 21, 2008

TO: IMP FILES

FROM: Carter Fairless

SUBJECT: **RESPONSE TO NOA LETTER RECEIVED FROM PHMSA 5/2/08**
CPF-4-2008-5012M
PROCEDURE CHANGES TO ADDRESS NOA LETTER ITEMS,
2nd SUBMITTAL

NOA ITEM

6. CITGO must characterize specific factors in their Risk Assessment model in more detail to provide for more accurate risk scores. The model should be evaluated to identify factors where increased specificity in scoring would provide more meaningful results. Examples of factors that improvements are needed in include the ILI indicated metal loss variable which is scored as 0 for less than five years and scored as 10 if greater than five years; and the internal corrosion threat variable which may not change beyond the referenced 30% threshold.

CITGO reviewed our entire risk model in detail and modified, where necessary, to provide more meaningful results. Example of changes:

- ILI metal loss variable scoring as 0 for less than 5 years and scored as 10 if greater than five years was eliminated.
- New factors for external and internal metal loss were created with scoring that eliminated the issue noted in the NOA item regarding the scoring not changing beyond a 30% threshold.
- Other factors were changed in order to utilize more actual data in lieu of SME derived input. More information regarding this can be found in the next item.

Documentation regarding changes to the risk model can be found in PR0013 and the *CITGO Risk Model – Data Sources and Configuration* document, both of which are attached.

CITGO PROCEDURE CHANGES

IMP-PR013 THREAT IDENTIFICATION AND RISK ASSESSMENT (COPY ATTACHED):

- 6.5.4
- See Attachment I, Table 1
- See Attachment II, Risk Assessment Questionnaire

NOA ITEM

7. CITGO's process for adequately identifying dominant risk factors in their likelihood of failure analysis must be modified to include the use of GIS/PODS data in the risk model input versus the SME-derived input information. CITGO's current process has little variation over a particular assessment section, and it is difficult to gain threat insights for location-specific pipelines.

CITGO reviewed our risk model and modified the model to use GIS data wherever possible. In addition, we also modified the model to utilize the most recent ILI assessment data for external metal loss, internal metal loss, and geometry indications. Documentation regarding changes to the risk model can be found in PR0013 and the *CITGO Risk Model – Data Sources and Configuration* document, both of which are attached. These changes increase the variation across an assessment section and make it easier to gain location specific threat insights.

CITGO PROCEDURE CHANGES

IMP-PR013 THREAT IDENTIFICATION AND RISK ASSESSMENT (COPY ATTACHED):

- 6.5.4

NOA ITEM

8. CITGO must modify the process for facility risk analysis to ensure all available information about the integrity of the entire pipeline system, including facilities, is analyzed. This approach is required for identifying specific facility risks and can be included in system wide prioritizing of preventive & mitigative measures.

At the time of the audit, CITGO considered facilities without breakout tanks part of the pipeline risk assessment. A separate procedure (IMP-PR0008 Facility Risk Assessment) addressed facilities that had breakout tanks. IMP-PR0008 was reviewed during the audit and is not attached. A new procedure, IMP-PR0017 Facilities without Breakout Tanks Risk Assessment was created to address NOA item 8. CITGO continues to address facilities without breakout tanks during the pipeline risk assessment. In addition, all facilities are now specifically addressed in either IMP-PR0008 or new procedure IMP-PR0017.

NEW CITGO PROCEDURE

IMP-PR0017 FACILITIES WITHOUT BREAKOUT TANKS RISK ASSESSMENT (COPY ATTACHED):

NOA ITEM

9. CITGO must modify their process for evaluation of pipeline integrity to provide sufficient detail such that an effective integrity evaluation process can be consistently performed. This process must be distinct from the reassessment interval determination process and provide an evaluation of the effectiveness of the ongoing management of pipeline integrity.

CITGO created a new procedure to address this NOA item.

NEW CITGO PROCEDURE

IMP-PR0018 CONTINUAL EVALUATION (COPY ATTACHED)

NOA ITEM

10. CITGO must modify the process for considering specific risk factors for determining reassessment intervals and their priority in sufficient detail to ensure consistent application, and this evaluation must be based on the impact the pipeline segment risk factors have on the HCAs.

CITGO revised and renamed existing procedure PR0015 to address this NOA item

CITGO PROCEDURE CHANGES

IMP-PR0015 REASSESSMENT INTERVAL PROCEDURE (COPY ATTACHED):

- 7.5.1
- 7.5.3

8/21/2008

Citgo Risk Model - Data Sources and Configuration

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Pipeline Centerline			L_Pipeline	PolylineM	None	CITGO_SDE				-	L_Pipeline is in NAD83	
Pipeline Units - 1	REPORTING UNITS		**Assessable Segments**			CITGO PODS		GFVU_L_OperationalUnit		-		
Consequence - 1		1	**Population**	Linear Event	Simple linear event	CITGO PODS	N/A	CPL _RMPopulatedArea	Class	10	Direct HPA (10), Direct OPA (8), Indirect HPA (9), Indirect OPA (7), Could-affect HPA (8), Could-affect OPA (6)	
Consequence - 2			**Drinking Water**	Linear Event	Simple linear event	CITGO PODS	N/A	CPL_RMDrinkingWater	Class	6	Direct DW (10), Indirect DW (5), Could-affect DW (3)	
Consequence - 3	RECEPTORS		**Ecological Areas**	Linear Event	Simple linear event	CITGO PODS	N/A	CPL_RMEcological	Class	3	Direct ECO (10), Indirect ECO (5), Could-affect ECO (3)	
Consequence - 4			**Commercially Nav. Waterways**	Linear Event	Simple linear event	CITGO PODS	N/A	CPL_RMCNW	Class	3	Direct CNW (10), Indirect CNW (5), Could-affect CNW (3)	
Consequence - 5			**Local Knowledge**	polygon	intersect	CITGO_SDE	N/A	Local_Knowledge	LK_Factor	3	Dense Population (10), National Resource (3), Water Resource (5), Farm (2)	Refresh factor classification
Consequence – 5A			**Potential NHD**	Linear Event	Simple linear event	CITGO PODS	N/A	CPL_RMNHD	Class	1	Direct NHD (10), Indirect NHD (0), Potential NHD (1)	
Consequence - 6	PRODUCT	1	**Product Type**	Linear Event	Simple linear event	CITGO PODS	N/A	GFVU_L_Pipeline	Product	1	Highly Volatile Liquids (10), Hydrogen (9), Natural Gas (8), Liquids or Gasoline (6), Crude Oil (5), Jet Fuel or Diesel (4)	
Consequence - 7		1	**Spill Volume**	Point Event	midpoint	CITGO PODS	N/A	GFVU_P_ReleasePoint	GFVolume_BBLS	3	> 10,000 bbls (10), 5,000.001-10,000 bbls (7), 1,000.001-5,000 (5), 500.001-1,000 (3), 0-500 bbls (1)	
Consequence - 8	SPILL SIZE		**Leak Detection Capabilities**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	LDC_Factor	1	SCADA RTTM (1), SCADA CMB (2), SCADA volume balance (3), Leak Detection Cable (3) , Line balance w/ monitoring (5), Line balance only (8), Visual (10)	Refresh factor classification
Consequence - 9			**Emergency Response Capabilities**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	ERC_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood - 1	THIRD PARTY DAMAGE	8	Depth of Cover	polygon	intersect	CITGO_SDE		minimum_cover	DOC_Factor	2	N/A (0), Exceeds minimum (1), Meets minimum w/ measures (2), Meets minimum (3), Below minimum w/ measures (4), Unknown (7), Below minimum (10)	Refresh factor classification
Likelihood - 2			Above Ground Facility Damage	polygon	intersect	CITGO_SDE		facility_damage	FacilityTPD_Factor	1	N/A (0), Very low (1), Low (3), Medium (7), High (10)	
Likelihood – 3			Activity Level	polygon	intersect	CITGO_SDE		Activity_level	Activity_Factor	2	High (10), Medium (7), Low (3), None (0)	Refresh factor classification
Likelihood - 4			One-Call	polygon	intersect	CITGO_SDE		one_call	OneCallEffect_Factor	1	N/A (0), Ineffective (10), Low effectiveness (7), High effectiveness (1)	Refresh factor classification
Likelihood – 5			Line Locating	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Damage_Prevention_GF		LineLocating_Factor	1	Excellent (1), Good (3) Adequate (5) Inadequate (10), N/A (0)	Refresh factor classification
Likelihood - 6			Public Awareness	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Damage_Prevention_GF		PA_Factor	1	Excellent (1), Good (3) Adequate (5) Inadequate (10), N/A (0)	Refresh factor classification
Likelihood - 7			Right of Way	polygon	intersect	CITGO_SDE		Pipeline_ROW	ROW_Factor	1	Poor (10), Below average (7), Average (5), Good (3), Excellent (1), Unknown (7)	Refresh factor classification
Likelihood – 8			Patrol Frequency	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Damage_Prevention_GF		Patrol_Factor	1	Less than minimum (10), Meets minimum (3), Exceeds minimum (1), Unknown (10)	
Likelihood – 9			Geometry ILI Top Side	Point event	Buffer 250'	Citgo_RFM_Data.mdb	Geo_Filtered_GF (query)		TopDepthPercent	2	>=2% (10), >=1% and <2% (5), >=0 and <1% (0)	Only consider dents >=1%
Likelihood – 9A			Geometry ILI Top Side Clustering	Point event	Sliding Distance 250'	Citgo_RFM_Data.mdb	Geo_Filtered_GF (query)		TopDepthPercent	2	>=3 occurences (10), 2 occurences (5), <2 occurences (0)	Only consider dents >=1%
Likelihood – 9B			Geometry & FLC	Point Event	BufferFLC by 250'	PODS / Citgo_RFM_Data.mdb	Geo_Filtered_GF (query)	GFVU_P_ForeignLineCrossing	TopDepthPercent	2	If Top side anomaly within buffer (10), If not (0)	Intersecting GILI factor with FLC table
Likelihood – 10			TPD Incident History	polygon	intersect	CITGO_SDE		Activity_level	TPD_Factor	5	>=3 (10), 1-2 (5), 0 (0)	
Likelihood – 11			Previously Damaged Pipe	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Failures_GF		PDPFailure_Factor	5	>=3 (10), 1-2 (5), 0 (0)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood - 12	CORROSION	4	Atmospheric Exposures	polygon	intersect	CITGO_SDE		atmos_corrosion	AtmExposure_Factor	2	Splash zone (10), Trapped water (7), Ground/air (5), None (0)	
Likelihood - 13			Atmospheric Conditions	polygon	intersect	CITGO_SDE		atmos_corrosion	AtmCondition_Factor	1	Chemical Marine (10), Chemical High (9), Marine (7), High (5), Chemical Low (3), Low (1)	
Likelihood - 14			Atmospheric Coating	polygon	intersect	CITGO_SDE		atmos_corrosion	AtmCoating_Factor	1	Excellent (1), Good (3), Fair (5), Poor (10), Unknown (7)	
Likelihood - 15			Atmospheric Corrosion Evidence	polygon	intersect	CITGO_SDE		atmos_corrosion	AtmCorrEvidence_Factor	3	Yes (10), Unknown (7), No (1)	Factor for spans only, not Valve sites
Likelihood - 16			Atmospheric Corrosion Failure History	polygon	intersect	CITGO_SDE		atmos_corrosion	AtmCorrFailures_Factor	5	>1 (10), 1 (5), 0 (0)	Factor for spans only, not Valve sites
Likelihood - 17			Soil Corrosivity	polygon	intersect	CITGO_SDE		soil_corrosivity	SoilCorr_Factor	1	High (10), Medium (5), Low (1)	
Likelihood - 18			Microorganisms	polygon	intersect	CITGO_SDE		soil_corrosivity	MIC_Factor	1	Yes (10), Unknown (7), No (1)	
Likelihood - 19			Coating Type	Linear Event	Simple linear event	CITGO PODS		GFVU_L_ExternalCoating	PrimaryCoatingType	1	HPCC (1), 3LPE (1), 3LPP (1), 2LFBE (1), FBE (2), X-Tru-Coat (4), Pritec (4), Yellow Jacket (5), ,Asphalt or Coal Tar or Somastic or TGC Coal Tar or Mastic (7) , Epoxy (5), Tape (8), Unknown (8), Wax Tape (7), Bare (10)	Refresh factor classification.
Likelihood - 20			Coating Condition	polygon	intersect	CITGO_SDE		coating_condition	CoatingCondition_Factor	3	Excellent (1), Good (3), Fair (5), Unknown (7), Poor (10)	
Likelihood - 21			Casing	Linear Event	Simple linear event	CITGO PODS		GFVU_L_Casing	NA	1	Not a casing (0); Casing exists (10)	Classification Method: default
Likelihood - 22			Casing Condition-1	Point events	Sliding Distance 50', Formula Calculation	CITGO PODS / Citgo_RFM_Data.mdb	ExtML_GF	GFVU_L_Casing	DepthPercent	4	Max anomaly depth. Formula multiplies Casing score times value derived from sliding distance calculation. In areas where no casing, result will be zero. In areas where casing exists result will be 1 times classification value =0 (0), >=0.1 and <20(1), >=20 and <30 (3), >=30 and <40 (4), >=40 and < 50 (5), >=50 and < 60 (8), >=60 (10)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood – 22a			Casing Condition-2	Point Events	Sliding Distance 50', Formula Calculation	CITGO PODS / Citgo_RFM_Data.mdb	ExtML_GF	GFVU_L_Casing	DepthPercent	4	Number of anomalies. Formula multiplies Casing score times value derived from sliding distance calculation. In areas where no casing, result will be zero. In areas where casing exists result will be 1 times classification value Classification to be determned. Initial values as follows: =0 (0), >=1 and <4 (1), >=4 and < 8 (3), >=8 and <16 (5), >=16 and < 32 (7), >=32 and < 64 (9), >=64 (10)	
Likelihood - 23			CP System Design	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	CP_ GF	N/A	CPDesign_Factor	1	Excellent (1), Good (4), Fair (8), None (10)	
Likelihood - 24			CP System Effectiveness	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	CP_ GF	N/A	CPEffectiveness_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood-70			CP System Availability	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	CP_ GF	N/A	YearsWithoutCP_Factor	1	>=0 and <1 (0), >=1 and <5 (5), >=6 and <9 (7), >=10 (10)	
Likelihood - 25			AC Interference Potential	polygon	intersect	CITGO_SDE	N/A	AC_Interference	AC_Factor	1	N/A (0), Possible (2), Unknown (7), Yes (10)	Refresh factor classification
Likelihood - 26			DC Interference Potential	polygon	intersect	CITGO_SDE	N/A	DC_interference	DC_Factor	1	N/A (0), Possible (2), Unknown (7), Yes (10)	Refresh factor classification
Likelihood - 27			Backfill	polygon	intersect	CITGO_SDE	N/A	Pipeline_segments_other	Backfill_Factor	1	Proper (1), Improper (10) Unknown (7), N/A (0)	Refresh factor classification
Likelihood - 28			External Metal Loss Data	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	External_Corrosion_GF	N/A	ExtCorr_Factor	5	Unknown (10), Yes (0)	Unknown means no ILI
Likelihood – 28A			External Metal Loss ILI	Point Event	Buffer 250'	Citgo_RFM_Data.mdb (data from recent ILI)	ExtML_GF	N/A	DepthPercent	3	=0 (0), >0 and <20(1), >=20 and <30 (3), >=30 and <40 (4), >=40 and < 50 (5), >=50 and < 60 (8), >=60 (10)	
Likelihood - 29			External Metal Loss Density	Point Event	Sliding Distance 1 mile	Citgo_RFM_Data.mdb (data from recent ILI)	ExtML_GF	N/A	NA	3	<20/mile (0), >=20 and <30 (3), >=30 and <60 (4), >=60 and <90 (5), >=90 and <120 (6), >=120 and <150 (7), >=150 and <180 (8), >=180 and <210 (9), >=210/mile (10)	
Likelihood - 30			External Corrosion Failures	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Failures_GF	N/A	ExtCorrFailure_Factor	5	>=3 (10), >=1 and <3 (5), 0 (0)	
Likelihood - 31			Product Corrosivity	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	ProductCorr_Factor	2	High (10), Medium (5), Low (2), None (0)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood - 32			Internal Corrosion Preventions	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	IntCorr_Preventions	1	Operational measures (1), Cleaning pigs w/ monitoring (5), Cleaning pigs (7), None (10), N/A (0)	
Likelihood – 33A			Internal Metal Loss Data	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Internal_Corrosion_GF	N/A	IntCorr_Factor	5	Unknown (10), Yes (0)	Unknown means no ILI
Likelihood – 33A			Internal Metal Loss ILI	Point Event	Buffer 250'	Citgo_RFM_Data.mdb (data from recent ILI)	IntML_GF	N/A	DepthPercent	3	=0 (0), >0 and <20(1), >=20 and <30 (3), >=30 and <40 (4), >=40 and <50 (5), >=50 and <60 (8), >=60 (10)	
Likelihood – 33B			Internal Metal Loss Density	Point Event	Sliding Distance 1 mile	Citgo_RFM_Data.mdb (data from recent ILI)	IntML_GF	N/A	NA	3	<20/mile (0), >=20 and <30 (3), >=30 and <60 (4), >=60 and <90 (5), >=90 and <120 (6), >=120 and <150 (7), >=150 and <180 (8), >=180 and <210 (9), >=210/mile (10)	
Likelihood - 34			Internal Corrosion Failures	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Failures_GF	N/A	IntCorrFailure_Factor	5	>=3 (10), >=1 and <3 (5), 0 (0)	
Likelihood - 35			Selective Seam Corrosion	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	N/A	Pipe_Segment_Other_Factors_GF	HAZ_Factor	10	Failures (10), Detected (8), Unknown (7), Undetected (2), N/A (0)	
Likelihood - 36			Stress Corrosion Cracking	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	N/A	Pipe_Segment_Other_Factors_GF	SCC_Factor	10	SCC failures (10), SCC detected (8), SCC susceptible (5), SCC undetected (2), N/A (0)	
Likelihood - 37			Landslide Hazard	Polygon	Intersect	CITGO_SDE	N/A	Landslide spatial layer		1	High (10), Med (5), Low (1)	NPMS Source/SDE
Likelihood - 38			Flood Hazard	Polygon	Intersect	CITGO_SDE	N/A	Floodzone spatial layer		1	High (10), Med (5), Low (1)	NPMS Source/SDE
Likelihood - 39			Huricane Hazard	Polygon	Intersect	CITGO_SDE	N/A	Hurricane spatial layer		1	High (10), Low (1)	NPMS Source/SDE
Likelihood - 40	OUTSIDE FORCE	5	Earthquake Hazard	Polygon	Intersect	CITGO_SDE	N/A	Earthquake spatial layer		1	High (10), Med (5), Low (1)	NPMS Source/SDE
Likelihood - 41			Frost Heave	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	FrostHeave_Factor	1	Subject(10), Not subject (1) N/A (0)	
Likelihood - 42			Traffic	polygon	intersect	CITGO_SDE	N/A	Traffic_Loading	TrafficLoad_Factor	1	Yes (10), No (1), N/A (0)	
Likelihood - 43			Spans	polygon	intersect	CITGO_SDE	N/A	Pipeline_span	Span_Support	1	Improper support (10), Proper support (1), Unknown (7)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood – 44	DESIGN CONSTRUCTION & MATERIALS	5	Diameter	Linear Event	Simple linear event	CITGO PODS		GFVU_L_Pipesegment	NominalOutsideDiameter	4	=> 38" (10), 32"-36" (9), 26"-30" (8), 20"-24" (7), 14"-18" (6), 12" (5), 10" (4), 8" (3), 6" (2), <=4" (1)	
Likelihood – 45			Wall Thickness	Linear Event	Simple linear event	CITGO PODS		GFVU_L_Pipesegment	NominalWallThick	2	<0.225" (10),>=0.225" and <0.280" (7), >=0.280 and < 0.322 (5) >=0.322 and <.375" (3), >=0.375 and <0.500" (2), >= 0.5" (1), Unknown (10)	
Likelihood - 46			Maximum Operating Stress	Linear Event	Formula Calculation	CITGO PODS and Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	GFVU_L_Pipesegment	PODS fields: NominalWallThick NominalOutsideDiameter SMYS PipeLongitudinalSeamFactor Database fields MaximumOperatingPressure	3	Formula: MaximumOperatingPressure / [(2 * SMYS * NominalWallThick / NominalOutsideDiameter) * PipeLongitudinalSeamFactor] If NominalWallThick = Unknown use 0.125 If NominalOutsideDiameter = Unknown use 48 If SMYS = Unknown use 24,000 If PipeLongitudinalSeamFactor = Unknown use 0.8 >= 0.7 (10), >=0.65 and <0.7 (9), >=0.6 and <0.65 (8), >=0.55 and <0.6 (7),>= 0.5 and <0.55 (6), >=0.45 and <0.5 (5), >=0.4 and <0.45 (4), >=0.3 and <0.4 (3), >=0.201 and <0.3 (2), >=0 and <0.2 (1)	Refresh factor classification if new NominalWall Thick, SMYS, or NomOD is added
Likelihood - 47			Normal Operating Stress	Linear Event	Formula Calculation	CITGO PODS and Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	GFVU_L_Pipesegment	PODS fields: NominalWallThick NominalOutsideDiameter SMYS PipeLongitudinalSeamFactor Database fields NormalOperatingPressure	2	Formula: NormalOperatingPressure / [(2 * SMYS * NominalWallThick / NominalOutsideDiameter) * PipeLongitudinalSeamFactor * 0.72] If NominalWallThick = Unknown use 0.125 If NominalOutsideDiameter = Unknown use 48 If PipeLongitudinalSeamFactor = Unknown use 0.8 If SMYS = Unknown use 24,000 >=0.8 (10), >=0.6 and <0.8 (7), >= 0.4 and <0.6 (5), >=0.2 and <0.4 (3), >=0 and <0.2 (1)	
Likelihood - 48			Pressure Surge	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF		PressureSurge_Factor	1	High (10), Low (1), Unknown (7), None (0)	

Likelihood - 49	**Construction Year**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_GF		Install_Age	1	>=0 and <20 (1), >=20 and <30 (3), >=30 and <40 (5), >=40 and <50 (7), >=50 and <60 (9), >=60 (10)	
Likelihood - 50	**Construction Quality - Joining**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_Other_Factors_GF		Joining_Factor	1	Questionable w/ failures (10), Questionable no failures (7), Unknown (7), Meets Standards (0)	Refresh factor classification
Likelihood - 51	**Construction Quality - Bends**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_Other_Factors_GF		Construction_Factor	1	Yes w/ failures (10), Yes no failures (7), No (0), Unknown (7)	Refresh factor classification
Likelihood - 52	**Material Defects**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_Other_Factors_GF	N/A	Materials_Factor	1	Yes (10), No (0), Unknown (7)	
Likelihood - 53	**Seam Fatigue**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_Other_Factors_GF	N/A	SeamDefects_Factor	10	Seam failures (10), Susceptible (9), Unknown (7), Not susceptible (1), N/A (0)	Refresh factor classification
Likelihood - 54	**Seam Assessment**	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipe_Segment_Other_Factors_GF	N/A	Seam_Assessment_Factor	2	Hydro (1), ILI Crack (1), No Assessment (10), N/A (0)	

	Group	Wt	Factor	Data Type	Processing	Citgo Data Set	Access Table	PODS View	Field	Wt	Classification	Clarification
Likelihood – 55	INCORRECT OPERATIONS	3	Overpressure Potential	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	Overpressure_Factor	3	Likely (10), Possible (7), Unlikely (3), Impossible (0)	
Likelihood – 56			Pressure Monitoring	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	PressureMonitoring_Factor	3	Observation w/ control (1), Observation only (5), None (10)	
Likelihood – 57			Communications (SCADA)	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	SCADA_Factor	4	Excellent (1), Good (3), Adequate (5), None (10)	
Likelihood – 58			Mechanical Error Preventers	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	ErrorPreventers_Factor	2	Excellent (1), Good (3), Adequate (5), None (10)	
Likelihood - 59			Hazard and Abnormal Operating Conditions Identification	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	HAZOP_Factor	2	All understood (1), Most understood (3), Obvious understood (5), Few understood (7), None (10)	
Likelihood - 60			Training and Qualifications	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Maintenance_Unit_GF	N/A	TrainingOQ_Factor	2	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood - 61			Drug Testing	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Maintenance_Unit_GF	N/A	DrugTesting_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood - 62			Procedures	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	Procedures_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood – 63			Documentation	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Maintenance_Unit_GF	N/A	Documentation_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood - 64			Complexity of Operations	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Operational_GF	N/A	Complexity_Factor	3	Simple (1), Complex (5), Very complex (10)	
Likelihood - 65			Human Error Incident History	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Pipeline_Section_Failures_GF	N/A	HumanError_Factor	2	>=3 (10), >=1 and <3 (5), 0 (0)	
Likelihood - 66	EQUIPMENT	2	Equipment Condition	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Equipment_GF	N/A	Equipment_Factor	2	Excellent (1), Good (3), Average (5), Poor (10)	
Likelihood - 67			Maintenance Program	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Maintenance_Unit_GF	N/A	Maintenance_Factor	1	Excellent (1), Good (3), Adequate (5), Inadequate (10)	
Likelihood - 68			Buried Flanges	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Flanges_GF	N/A	BuriedFlange_Factor	1	>=20 (10), >=10 and <20 (7), >=3 and <10 (5) >=1 and <3 (3), 0 (0)	
Likelihood - 69			Flange Condition	Linear Event	Simple linear event	Citgo_RFM_Data.mdb	Flanges_GF	N/A	FlangeCondition_Factor	1	Good (1), Poor (10), N/A (0)	

CITGO Doc # **IMP-PR0013**	**Pipeline Integrity Management**	
	Doc. Title: **THREAT IDENTIFICATION AND RISK ASSESSMENT PROCEDURE**	**CITGO Pipeline Company** Tulsa, Oklahoma
Reviewed By: C. Fairless Pipeline Integrity Manager	Approved By: K. Lloyd Manager Engineering, Pipeline Compliance & Control	Approved By: K. Powers General Manager, Terminals and Pipelines
Original Release Date: 11/01/04	Revision 2 Rev. Release Date: 8/18/2008	Page 1 of 46

1 PURPOSE

1.1 The purpose of this document is to describe the Risk Assessment process that CITGO utilizes to identify and analyze potential threats and risk drivers.

2 SCOPE

2.1 This procedure applies to all liquid pipelines owned by CITGO Pipeline Company and other pipelines operated by CITGO Pipeline Company that could affect an HCA.

2.2 After the initial Baseline Plan Risk Assessment, the Pipeline Integrity Manager conducts the Risk Assessment for the Mid-Continent and Gulf Coast areas of CITGO Pipeline as a group and a separate Risk Assessment for the West Shore Pipe Line and CITGO Terminal lines systems.

2.3 An integrity incident or other event can also trigger a re-assessment of risk for the affected pipeline section.

2.4 The Risk Assessment process is closely integrated with and is used to support Preventive and Mitigative Measures Evaluation process (IMP-PR0009)

3 RELATED DOCUMENTS

3.1	IMP-PL0001	Integrity Management Plan for DOT Part 195 and Texas Rule 8.101
3.2	IMP-PR0004	Risk Segment Identification Procedure
3.3	IMP-SC0002	CITGO Continual Assessment Plan
3.4	IMP-SC0008	CITGO Terminal Continual Assessment Plan
3.5	IMP-PR0009	Preventive and Mitigative Measures Evaluation

3.6 IMP-PR0015 Reassessment Interval Procedure

3.7 IMP-PR0018 Continual Evaluation Procedure

3.8 API 1160 Managing System Integrity for Hazardous Liquid Pipelines

4 DEFINITIONS

4.1 Baseline Assessment Plan – Risk-based, prioritized schedule outlining the assessment methods to be used in assessing the integrity of the pipeline segments and the anticipated dates of completion for each of the assessments.

4.2 Continual Assessment Plan – Risk-based, prioritized schedule outlining the assessment methods to be used in assessing the integrity of the pipeline segments after the initial Baseline Assessments and the anticipated dates of completion for each of the re-assessments.

4.3 High Consequence Area (HCA) – As defined by the Department of Transportation Section 195.450 and includes impacts to "Commercially Navigable Waterways," "High Population Areas," "Other Population Areas," and "Unusually Sensitive Areas" (USA).

4.4 Pipeline Risk – Function of the likelihood of an event or condition to lead to a potential product release (incident) and the consequence of that incident occurring. (API 1160).

4.5 Pipeline Risk Segment – A portion of a Pipeline Section that intersects an HCA or could affect an HCA by any of the following methods: (1) Direct intersection with an HCA or NHD stream, (2) ¼ mile buffer around an HCA for hazardous liquid lines, (3) 5 mile buffer around an HCA for highly volatile liquid lines, or (4) Land or water transport of a release to an HCA or NHD stream. A Pipeline Section may have multiple risk segments.

4.6 Pipeline Section – Pre-defined portion of a pipeline that can be internally inspected, from launching device to receiving device (piggable section), or a portion of a pipeline that can be hydro-tested.

4.7 Pipeline System – A "System" is a portion of CITGO's pipelines, grouped by service to different geographical areas, and defined as: Lakemont Pipeline

System, Eagle Pipeline System, West Shore Pipeline System, CASA Pipeline System, and Gulf Coast Pipeline System.

4.8 Risk Assessment – Estimation of risk for the purposes of decision making. (API 1160)

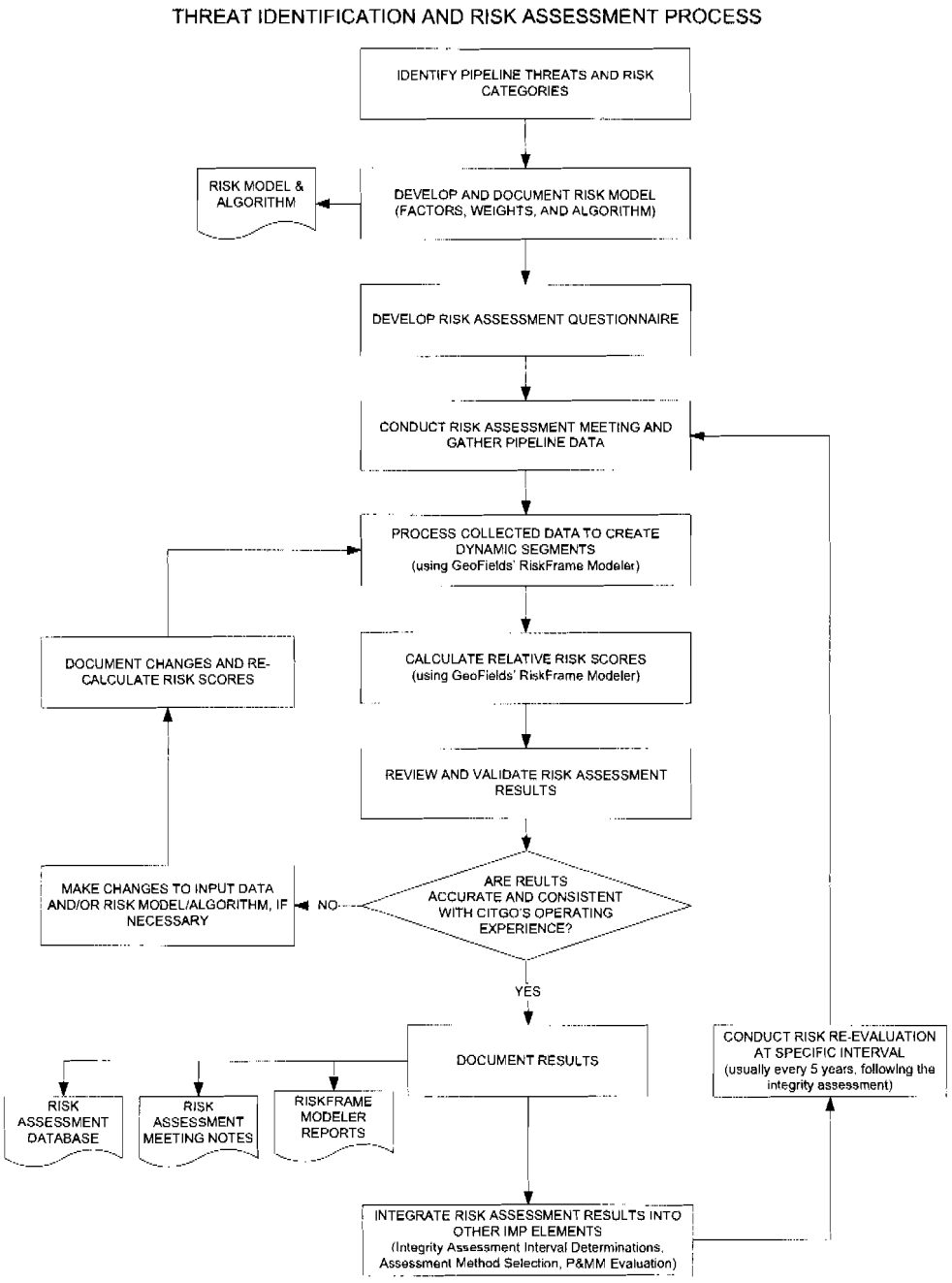
5 RESPONSIBILITIES AND TRAINING

5.1 The Pipeline Integrity Manager shall be responsible for ensuring that the appropriate personnel are trained on the risk assessment process and its objectives.

5.2 The Pipeline Integrity Manager is responsible for scheduling and conducting Risk Assessment meeting, maintaining and updating risk data, and integrating Risk Assessment results with other IMP elements.

5.3 The Risk Assessment Team members are responsible for preparing for and attending Risk Assessment meetings, gathering and providing requested information, and assuring that input data is accurate to the best of their knowledge.

PROCESS FLOW DIAGRAM



6 PROCEDURE

6.1 Risk Assessment Objectives

The Risk Assessment process has the following objectives:

- Collect latest data and store in one location
- Integrate data elements to identify high-risk areas
- Identify risk drivers and major threats
- Gain better understanding of pipeline conditions and address risks before failures occur
- Help prioritize assessments and repairs
- Allocate resources based on risks
- Comply with regulatory requirements
- Increase operational performance by managing risks

6.2 Risk Assessment Schedule and Frequency

6.2.1 The Risk Assessment meetings are conducted annually for each pipeline system to cover the pipeline sections that had integrity assessments completed (includes completion of the ILI tool run or hydrotest, data analysis, and required immediate, 60-day, and 180-day condition repairs).

6.2.2 The Risk Assessment re-evaluations will usually be conducted every 5 years for each Pipeline Section, unless a more frequent integrity assessment schedule is determined or the Risk Assessment is triggered by other events.

6.2.3 Other events that could trigger Risk Assessments include:

- Changes in pipeline operating conditions
- Pipeline incident or failure

- Changes in pipeline environment, including newly identified HCAs
- New insights on pipeline integrity that affect pipeline risk
- Other events that require risk review, as determined by the Pipeline Integrity Manager

6.3 Tools and Applications

The Risk Assessment process utilizes the following tools to gather, integrate, and evaluate integrity-related data and pipeline information:

- CITGO Geographical Information System (GIS) database accessed using GeoFields' Facility Explorer application
- Pipeline Risk Assessment application
- GeoFields' RiskFrame Modeler application
- Risk Data Report application

6.4 Risk Assessment Meeting Participants

6.4.1 Participants in the Risk Assessment process are subject-matter experts (SMEs) knowledgeable about the particular integrity issue or pipeline under evaluation, and are collectively known as the Risk Assessment Team.

6.4.2 The SMEs for CITGO include the following:

- Pipeline Integrity Manager or designated alternate
- GIS Analyst
- Each Area Supervisor for the system
- Each Corrosion Technician for the system

6.4.3 The following personnel may also be included, as needed:

- Integrity Engineer(s)

- Corrosion Engineer
- P/L technicians
- District Manager or Terminal Manager
- HSE representative for the system
- Consultants and other risk experts

6.5 Risk Assessment Data and Factors

6.5.1 CITGO's method to evaluate risk uses input data to characterize the physical condition of pipelines and the surrounding population and environment. This information, including "risk factors" required by regulations (195.452(e), 195.452(g), and 195.452(i)(2)), is collected and processed utilizing methodology known as relative risk index model (based on W. Kent Muhlbauer theory and his "Pipeline Risk Management Manual", Third Edition).

6.5.2 The Risk Model produces an estimate of the risk for a particular section of pipe, called "dynamic segment", by applying numerical "weights" to risk factors and calculating relative risk score.

6.5.3 CITGO's Risk Assessment process is designed to comply with the Rule requirements, and to identify potential threats to pipeline integrity and evaluate the magnitude of the consequences in the event of pipeline failure, so that preventive and mitigative actions could be taken to reduce the risk, where necessary.

6.5.4 Wherever practical, actual data from the GIS database and recent ILI assessment results will be used for risk model input in lieu of subject matter expert derived input information. Examples of where actual data should be used include risk model factors that utilize:

- Pipe Outside Diameter
- Pipe Wall Thickness
- Pipe Specified Minimum Yield
- Pipe Longitudinal Seam Factor or Seam Type

- Coating Type
- Cased crossings (presence or absence of casing)
- Geometry or Metal Loss depth or density calculations
- Product transported

6.5.5 The seven main risk categories that are addressed in CITGO's Risk Assessment process include the following:

- Third Party Damage
- Corrosion (external buried pipe corrosion, atmospheric corrosion, internal corrosion, selective seam corrosion, and stress corrosion cracking)
- Outside Force
- Design , Construction, and Materials
- Incorrect Operations
- Equipment
- Consequences

6.5.6 To evaluate each of these risk categories, CITGO conducts Risk Assessment meetings to gather, review, and integrate pipeline data. The Risk Assessment application is used for data entry and storage.

6.5.7 The collected data is then exported and transferred into the RiskFrame Modeler application, which processes data, creates dynamic segments, and calculates relative risk score for each individual dynamic segment, based on pre-determined weights and factor values. Attachment I of this procedure provides detailed information on CITGO's relative Risk Model.

6.5.8 The information used in relative Risk Model is gathered for each pipeline section using a risk questionnaire with multiple-choice answers. Where risk factors or pipe data differ along the pipeline, CITGO creates multiple segments to capture the differences in risk.

Conservative assumptions are used where data are unavailable or unknown. The Risk Assessment application and questionnaire is described in Attachment II of this procedure.

6.5.9 To complete the risk questionnaire, CITGO relies on the knowledge and experience of the subject-matter experts (SMEs) for that pipeline section or system, as well as information stored within the GIS databases.

6.5.10 Other data sources used during the Risk Assessment meeting include, but are not limited to, the following:

- ILI reports
- Hydrotest information
- Repair information and bell hole inspections (CPL11)
- CIS results
- CP data
- Span inspection reports
- Valve and equipment inspection reports
- Right-of-way patrol and surveillance reports
- One-call data
- Incident and failure history
- O&M, Public Awareness, OQ, Facility Response Plan and other manuals
- Alignment sheets, as-builts, and other construction drawings
- Pipeline maps and aerial photographs
- HCA locations and spill modeling results

6.6 Risk Data Quality and Maintenance

6.6.1 All information gathered during the Risk Assessment meeting is maintained by the Pipeline Integrity Manager in the Risk Assessment database and meeting notes. The Pipeline Integrity Manager is responsible for assuring data quality and conducting the efforts to obtain missing data, where necessary.

6.6.2 All changes made to the risk data must be documented with the Risk Assessment database. If changes are significant, they must be evaluated by the Risk Assessment Team to determine their impact on pipeline assessment schedule, assessment method, and preventive and mitigative measures.

6.7 Risk Assessment Results Validation

6.7.1 After the risk scores are calculated for each segment and before additional action is taken, CITGO validates the risk assessment results to ensure that the methods used have produced logical results that are consistent with CITGO's and the industry's experience.

6.7.2 The Pipeline Integrity Manager reviews the risk assessment results. Items to consider in the review may include:

- An investigation as to which factors contributed the most to the risk score for the highest risk locations
- Review of the major sources of uncertainty and identification of means to correct any that exist

6.7.3 The Pipeline Integrity Manager reviews the risk assessment results with the Risk Assessment Team as part of the quality control process. The results should be compared to operating history and local knowledge to ensure that reasonable results have been produced.

6.7.4 If the risk results appear to be "suspect" to the members of the Risk Assessment Team, CITGO will investigate the suspect results and make a determination whether any Risk Model changes are warranted. If CITGO determines that the Risk Model needs to be modified in order to provide more meaningful results, then CITGO documents the issues, reviews, and modifies the Risk Model and then recalculates the risk score for each Pipeline Section.

6.7.5 After the validation process has been completed and any needed changes have been made to the risk factors and scoring, the Risk Assessment results are used to support other IMP elements.

6.8 Risk Assessment Results Application

6.8.1 The Risk Assessment results can be viewed and analyzed using the following tools:

- Pipeline Risk Assessment application (allows user to view original input data by pipeline section)
- RiskFrame Modeler reports (allows user to view total risk scores and individual factor scores by individual dynamic segment, Risk Segment, or Pipeline Section)
- Risk Data Report application (allows user to view risk charts and graphs in order to identify high risk areas and risk drivers by Pipeline Section)
- Facility Explorer (allows user to view geographical locations of the specific Risk Segments, as well as their proximity to HCAs and other receptors)

6.8.2 Risk Assessment results are used to further support these Integrity Management processes:

- Preventive and Mitigative Measures Evaluation (IMP-PR0009) – to determine the major risk drivers and integrity issues and to design the preventive and mitigative measures to address them.
- Reassessment Interval Procedure (IMP-PR0015) – to provide guidance in selecting assessment method and schedule, based on identified threats.

6.9 Risk Assessment for Newly Identified HCA Segments, Idled, and New Assets

6.9.1 All newly identified segments that could affect HCAs must have the Risk Assessment process completed and must be incorporated into the Baseline Assessment Plan within one year from the date the segment is identified.

6.9.2 All newly constructed or converted assets (Category 3 pipelines) must have the Risk Assessment process completed and must be incorporated into the Baseline Assessment Plan within one year after the date the pipeline begins operation.

6.9.3 All newly acquired assets must have the Risk Assessment process completed within a year of asset acquisition, so that the new pipeline can be scheduled for assessment, as appropriate.

6.9.4 Previously idled out-of-service pipelines must have the Risk Assessment process completed prior to placing the line back to service. All deferred assessments and any known required repairs for which repair deadlines have passed must be completed as well. The Baseline Assessment Plan or re-assessment schedule, as appropriate, should be modified to assure that an assessment is completed by the appropriate deadline. If the deadline has expired, then the assessment must be completed as part of returning the line to service.

6.9.5 The Pipeline Integrity Manager is responsible for assuring that Risk Assessment are conducted in a timely manner for all newly identified HCA segments or new pipeline assets. To gather initial information on pipelines that previously were not included in the IMP, CITGO uses data gathering form provided in Attachment III.

7 RECORDS

7.1 Risk Assessment Team Meeting Minutes

7.2 Risk Assessment database

7.3 RiskFrame Modeler reports

7.4 Risk Model structure, weights, and algorithms (CITGO Risk Model Data Config document)

7.5 Justification and documentation of changes to the Risk Assessment process

ATTACHMENT I - RELATIVE RISK MODEL DESCRIPTION

Risk Methodology Overview

CITGO's Risk Model is a relative index-based model, which is based on risk theory by W. Kent Muhlbauer. The model was designed by CITGO's SMEs, in collaboration with Kendrick Consulting LLC and GeoFields. The risk algorithm and factor weights are chosen based on CITGO's operational experience, SME knowledge, W. Kent Muhlbauer theory, and pipeline industry statistics provided by PHMSA. Figures 1 and 2 illustrate risk score distribution within CITGO model, Figures 3-5 illustrate pipeline industry accident statistics, grouped by main causes.

The Risk Model results provide an insight to relative risk without making any absolute risk estimates. The high risk scores mean higher relative risk, as compared to other pipelines or pipeline segments. The group and factor weights are based on the significance of that factor (cause event), taking into the account both the likelihood of it occurring and the consequences that would be expected in the event of failure caused by that factor. For individual factors, their weights are based on the "importance" of that factor and its contribution to the overall risk. Each factor can have a value from 0 (not applicable) to 10 (highest risk).

The total risk score is calculated as follows:

Total Risk = Cause x Consequence

$Cause = (Score_{Cause} / Score_{MaxCause}) * 100\%$

$Consequence = (Score_{Cons} / Score_{MaxCons}) * 100\%$

$Score_{Cause/Cons} = \Sigma$ (Factor Value x Factor Weight x Group Weight)

Risk scores are generated within RiskFrame Modeler application for dynamic segments along the pipeline. The application contains built-in data processing engine that integrates spatial data layers (e.g. HCA shapefiles) and tabular sources from Risk Assessment database. The properties of each risk factor can be re-configured and edited to seamlessly integrate new data into the risk model. The risk categories, groups, and factor weights, classifications, data configuration, and data sources used in GeoFields RiskFrame Modeler are documented in a separate document, maintained by Terminal and Pipeline Integrity Manager. Table 1 provides a summary of Risk Model factors and weights. The actual questionnaire used in Risk Assessment Application is included in Attachment II.

Table 1

Category Weight	Risk Group	Factor Description	Factor Weight	Maximum Score	Risk Group Total Score
1	Receptors	Population	10	100	260
		Drinking water	6	60	
		Ecological areas	3	30	
		Commercially Navigable Waterway	3	30	
		Local Knowledge	3	30	
		Potential NHD	1	10	
	Products	Product Type	1	10	10
	Spill Size	Spill Volume-BBLs	3	30	50
		Leak Detection Capabilities	1	10	
		Emergency Response Capabilities	1	10	
8	Third Party Damage	Depth of Cover	2	20	2080
		Above Ground Facility Damage	1	10	
		Activity Level	2	20	
		One Call	1	10	
		Line Locating	1	10	
		Public Awareness	1	10	
		Right of Way	1	10	
		Patrol Frequency	1	10	
		Geometry ILI Top Side	2	20	
		Geometry ILI Top Side Clustering	2	20	
		Geometry and Foreign Line Crossing	2	20	
		TPD Incident History	5	50	
		Previously Damaged Pipe	5	50	
4	Atmospheric Corrosion	Atmospheric Exposures	2	20	480
		Atmospheric Conditions	1	10	
		Atmospheric Coating	1	10	
		Atmospheric Corrosion Evidence	3	30	
		Atmospheric Corrosion Failure History	5	50	
	External (Buried Metal) Corrosion	Soil Corrosivity	1	10	1960
		Microorganisms	1	10	
		Coating Type	1	10	
		Coating Condition	3	30	
		Casing	1	10	

Category Weight	Risk Group	Factor Description	Factor Weight	Maximum Score	Risk Group Total Score
		Casing Condition – 1 (depth)	4	40	
		Casing Condition – 2 (anomaly count)	4	40	
		CP System Design	1	10	
		CP System Effectiveness	1	10	
		CP System Availability	1	10	
		AC Interference Potential	1	10	
		DC Interference Potential	1	10	
		Backfill	1	10	
		External Metal Loss Data	5	50	
		External Metal Loss ILI Depth	3	30	
		External Metal Loss Density	3	30	
		External Corrosion Failures	5	50	
	Internal Corrosion	Product Corrosivity	2	20	
		Internal Corrosion Preventions	1	10	
		Internal Metal Loss Data	5	50	760
		Internal Metal Loss ILI	3	30	
		Internal Metal Loss Density	3	30	
		Internal Corrosion Failures	5	50	
	Selective Seam	Selective Seam Corrosion	10	100	400
	SCC	Stress Corrosion Cracking	10	100	400
5	Outside Force	Landslide Hazard	1	10	
		Flood Hazard	1	10	
		Hurricane Hazard	1	10	
		Earthquake Hazard	1	10	350
		Frost Heave	1	10	
		Traffic	1	10	
		Spans	1	10	
5	Design	Diameter	4	40	
		Wall Thickness	2	20	
		Maximum Operating Stress	3	30	600
		Normal Operating Stress	2	20	
		Pressure Surge	1	10	
	Construction	Construction Year	1	10	
		Construction Quality Joining	1	10	150
		Construction Quality Bends	1	10	

Category Weight	Risk Group	Factor Description	Factor Weight	Maximum Score	Risk Group Total Score
	Materials and Manufacturing Defects	Material Defects	1	10	650
		Seam Fatigue	10	100	
		Seam Assessment	2	20	
3	Operations	Overpressure Potential	3	30	360
		Pressure Monitoring	3	30	
		Communications SCADA	4	40	
		Mechanical Error Preventers	2	20	
	Human and Procedural Errors	Hazard Abnormal Operating Conditions	2	20	360
		Training and Qualifications	2	20	
		Drug Testing	1	10	
		Procedures	1	10	
		Documentation	1	10	
		Complexity of Operations	3	30	
		Human Error Incident History	2	20	
2	Equipment	Equipment Condition	2	20	100
		Maintenance Program	1	10	
		Buried Flanges	1	10	
		Flange Condition	1	10	

Figure 1

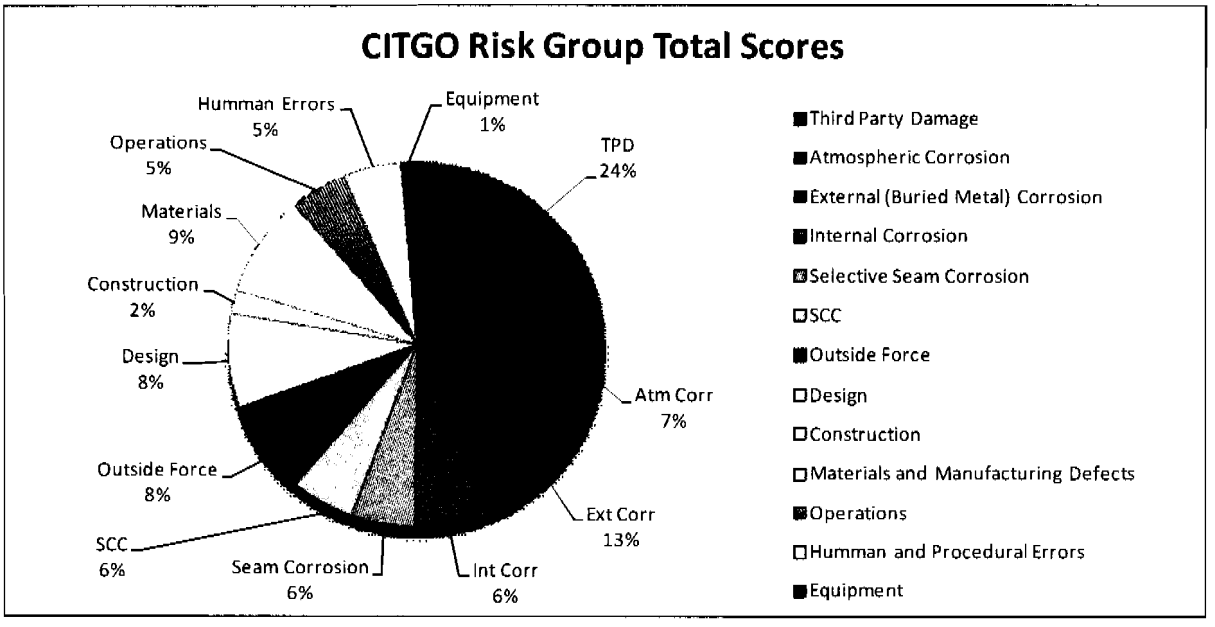


Figure 2

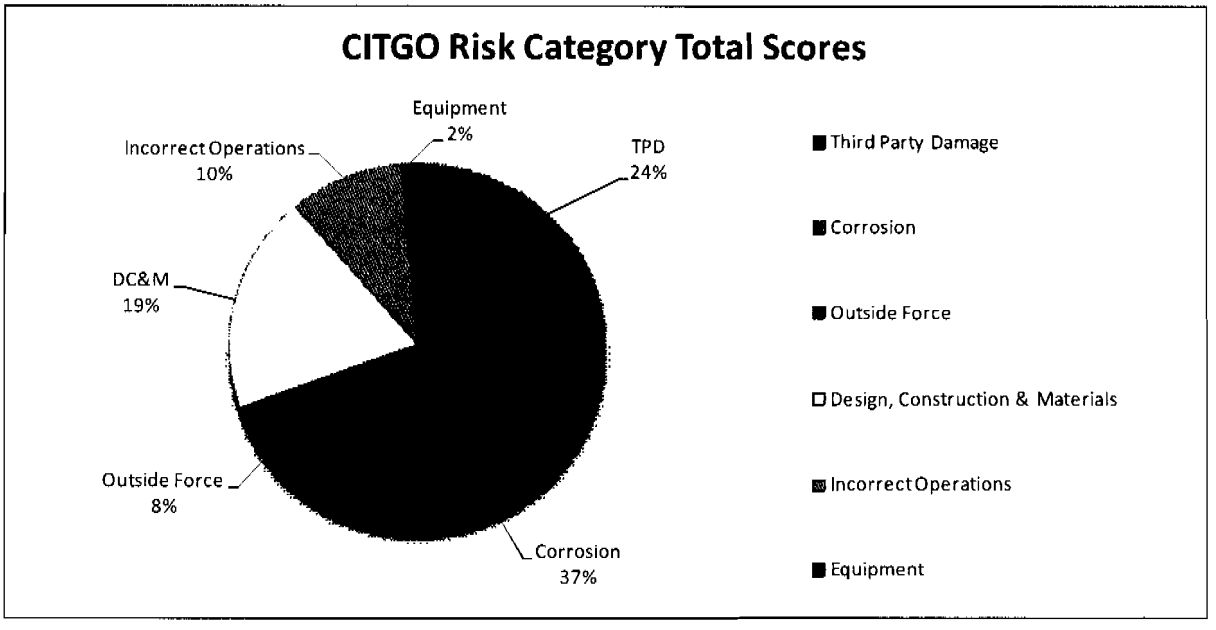


Figure 3

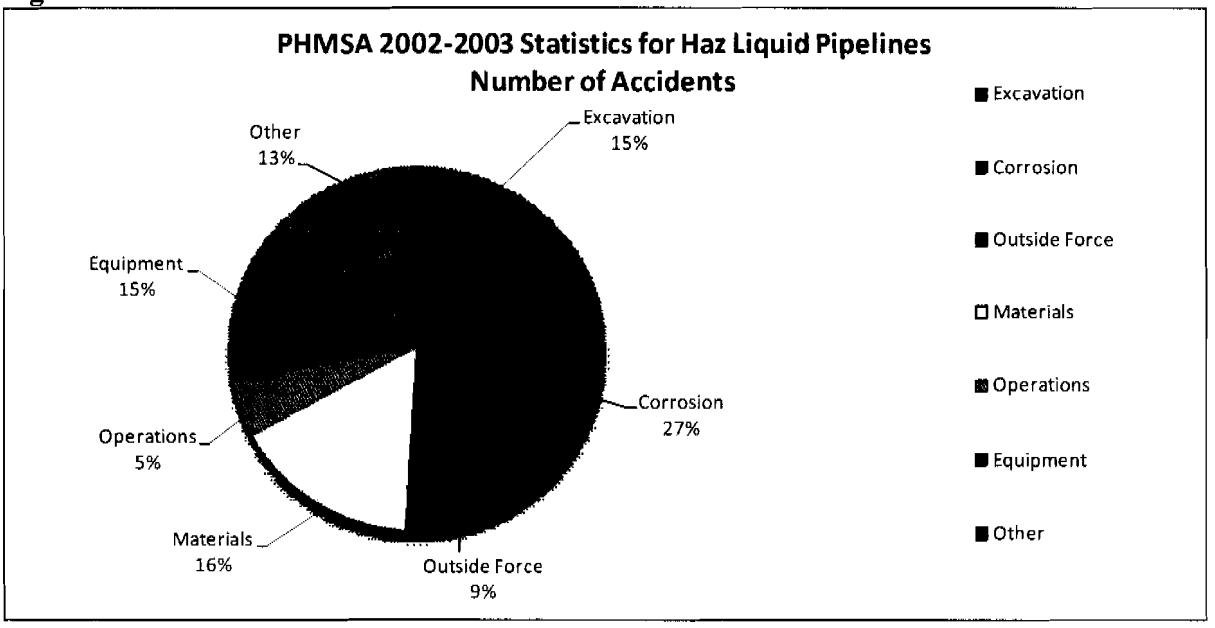


Figure 4

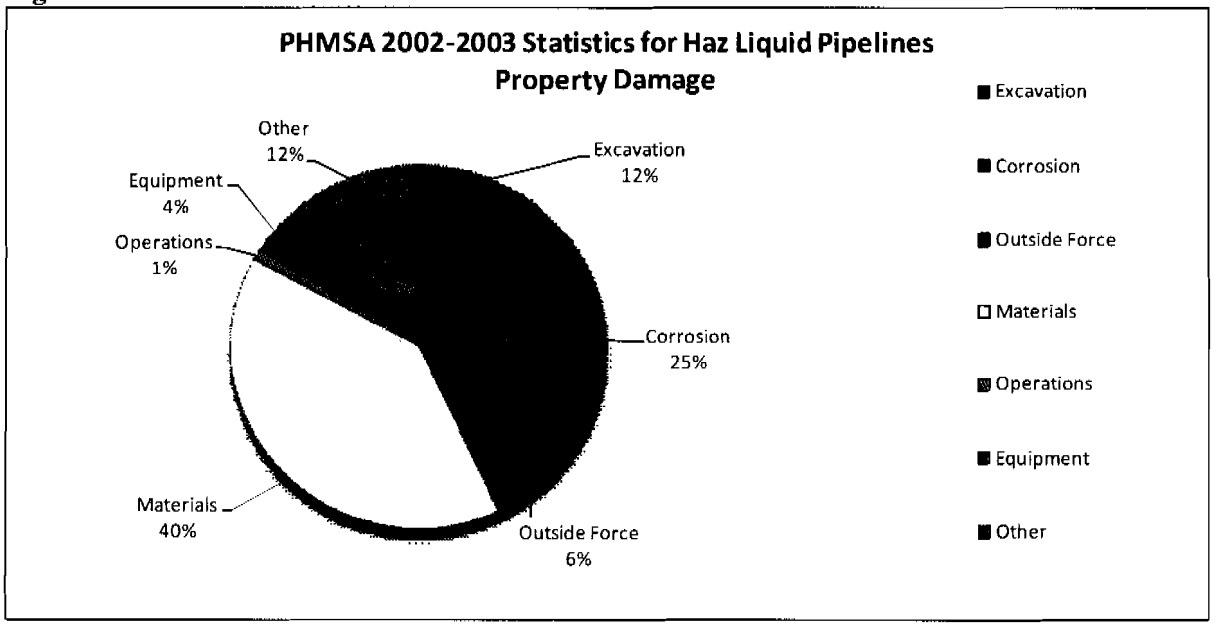
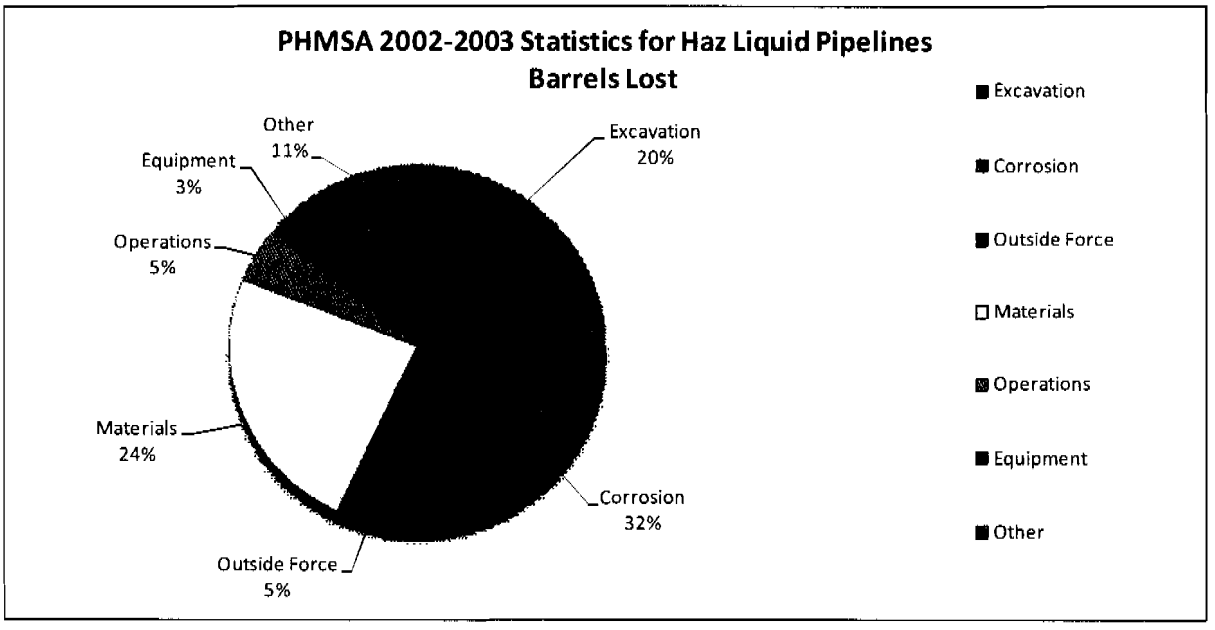


Figure 5


PHMSA 2002-2003 Statistics for Haz Liquid Pipelines
Barrels Lost
Other 11%
Excavation 20%
Equipment 3%
Operations 5%
Materials 24%
Corrosion 32%
Outside Force 5%
Excavation
Corrosion
Outside Force
Materials
Operations
Equipment
Other

ATTACHMENT II – RISK ASSESSMENT QUESTIONNAIRE

Form Name	Question	Answer
Verify Pipeline Data	*Pipeline Section ID No.*	
	Full Name and Description	
	Cumulative Station Start	
	Cumulative Station End	
	Engineering Station Start	
	Engineering Station End	
	Length in feet	=[EndCumSta]-[BegCumSta]
	Length in miles	=[EndCumSta]-[BegCumSta]/5280
	Common Name	
	Pipeline System Name	
	Company Name	
	OPS Operator ID	
	GFDM Pipeline ID	
	Jurisdiction	Interstate; Intrastate
	Regulated by	
	Status	In-service; Idle
	Product Type	NA – Actual data from GIS used for risk scoring
	Product Description	
	In service since (year)	
	State Origin	
	State Destination	
	Comment:	
Operational Data	*Maximum Operating Pressure (psi)*	
	Normal Operating Pressure (psi)	
	Flow direction (select):	One-way; Both ways
	Pressure cycles (describe):	
	Is this section piggable? (check if yes)	
	Does it have ILI launchers and receivers installed? (check if yes)	
	What are the leak detection capabilities for this pipeline section? (select one)	1 SCADA-based real time transient modeling (RTTM)
		2 SCADA-based compensated mass balance (CMB)
		3 SCADA-based volume balance (accounts for changes in volume due to pressure/temperature variations)
		4 Manual line balance with pressure and flow monitoring

Form Name	Question		Answer
		5	Manual line balance only (tank gauging or meter)
		6	Direct observation by operator and public
		7	Leak Detection Cable (or similar)
	Comment:		
	What are the characteristics of SCADA system for this pipeline section? (select one)	1	Excellent SCADA system - continuous monitoring of all critical activities and conditions (pump start/stop, tank transfers, valve closures, changes in flows, pressures, temperatures, and equipment status), local automatic or remote control, enforced protocol requiring real-time communications and coordination of all field actions through centralized control room, SCADA system reliability (uptime) exceeds 99.99%
		2	Good SCADA system- continuous monitoring of most critical activities, field actions are mostly coordinated through central control room, system reliability (uptime) exceeds 95%
		3	Adequate SCADA system - some critical activities are monitored, field actions are informally coordinated through control room, reliability is at least 90% operational
		4	None - no SCADA system or centralized monitoring system exists, or is not used in a manner that promotes human error reduction
	Comment:		
	How is pressure monitored for this pipeline section? (select one)	1	Remote observation and control - pressure is monitored from a remote location, remote control or pumps/valves or automatic shutdown is possible
		2	Remote observation only - pressure is monitored from a remote location, but remote control or automatic shutdown is not possible
		3	No pressure monitoring
	Comment:		
	Control Center location:		Tulsa; Other

Form Name	Question		Answer
	What is the potential for pressure surges (water hammer effect) greater than 110% of MOP occurring on this pipeline section? (select one)	1	Low potential - surges can happen, but devices such as breakout tanks, relief valves, slow valve closures, as well as operating procedures are in place; or surge occurrence is unlikely
		2	High potential - closure devices, equipment, and fluid velocity support the possibility of pressure surge. No mechanical preventers or operating procedures in place to prevent surges
		3	System cannot produce a pressure surge over 110% MOP
		4	Unknown potential/effects of pressure surges
	Comment:		
	What is the potential for overpressure event greater than 110% to occur on this pipeline section? (select one)	1	Likely - routine, normal operations could allow the system to reach 110% MOP, overpressure is prevented only by procedure or singe-level safety device; overpressure occurred on this system several times in the past
		2	Possible - overpressure can occur only through a combination of errors or omissions, and failure of safety devices; overpressure occurred in the past on this or similar system
		3	Unlikely - overpressure is theoretically possible (sufficient source pressure), but only through extremely unlikely chain of events, including errors, omissions, and safety device failures at more than two levels of redundancy; overpressure never occurred on this or similar system
		4	Impossible - pressure source cannot, under any circumstances, overpressure the pipeline
	Comment:		
	What mechanical error preventers exist on this pipeline section? (select one)	1	Excellent - system is "fail-safe" due to a highly sophisticated computer-based program with interlocks/software logic constraints that prevent incorrect operations; critical operations are linked to pressure, flow, temperature, etc. indications, which are set as "permissives" before action can occur

Form Name	Question		Answer
		2	Good - a computer-based program exists that helps to prevent most incorrect operations; system is not "fail-safe", but failure from incorrect operations is very unlikely
		3	Adequate - key-lock sequences, lock-out devices, and other methods are used to prevent incorrect operations; no computer-based programs are used; there is some potential for failure due to incorrect operations
		4	None - no mechanical error preventers exist; incorrect operations present a significant potential to failure
	Comment:		
	How well are hazards and abnormal operating conditions addressed for this pipeline section? (select one)	1	Hazards are clearly understood, all operating conditions and operating modes have been evaluated; different failure modes, including rare events have been considered; formal HAZOP studies performed routinely and are documented; personnel is trained to recognize all abnormal operating conditions
		2	Most hazards are understood and most failures modes are considered, personnel is trained to recognize abnormal operating conditions, HAZOP studies infrequent or not well documented
		3	Only most obvious scenarios have been addressed and documented, few HAZOP studies conducted
		4	Few operating modes/conditions have been evaluated, personnel may recognize only some abnormal operating conditions, no formal HAZOP studies performed
		5	No hazard analysis done
	Comment:		
	What is the quality of operation and maintenance procedures? (select one)	1	Excellent - formal, clear, and detailed procedures exist for all O and M activities/processes, procedures are reviewed and updated regularly, they are readily available and are actively used by pipeline personnel

Form Name	Question		Answer
		2	Good - formal procedures exist for all O&M activities/processes, procedures are reviewed and updated as required by regulations, but they are not always clear and/or may lack some detail
		3	Adequate - procedures exist for all required O and M activities/processes and meet minimum regulatory requirements
		4	Inadequate - procedures exist for some O and M activities/processes, but they are outdated, not clear, and lack detail
	Comment:		
	How complex are the operations for this pipeline section? (select one)	1	Very complex facility operations - multiple modes of pumping and product transfers requiring coordination between control room and several field personnel; complex third-party hand-offs
		2	Complex operations - several modes of pumping and product transfers requiring different valve opening/closing sequences; third-party hand-offs present a potential for failure do to incorrect operations
		3	Simple operations - do not involve multiple valve opening/closing sequences and third-party hand-offs
	Comment:		
	What are the emergency response capabilities for this pipeline section? (select one)	1	Excellent - a formal, tested, and proven response strategy is in place that exceeds minimum regulatory requirements and industry standards; emergency drills are conducted regularly; response equipment is located on site
		2	Good- a formal response strategy is in place that meets minimum requirements; local responders, response equipment is less that 2 hrs away
		3	Adequate - a response strategy meets minimum regulatory requirements; drills are not conducted frequently; response equipment is more than 2 hrs away
		4	Inadequate- a response strategy does not meet minimum regulatory requirements
	Comment:		

Form Name	Question		Answer
	Is pipeline segment subject to freeze-thaw cycles and damage from frost heave?	1	Subject to freeze-thaw cycles due to non-continuous operation or shallow depth
		2	Freeze-thaw cycles are not a threat due to continuous operations or adequate depth of cover
		3	Not applicable
	What is the corrosivity of the product transported? (select one)	1	Corrosive under some conditions (e.g., refined products)
		2	Mildly corrosive (e.g. crude oil)
		3	Strongly corrosive (e.g., high sulfur crude)
		4	Non-corrosive - 0% water content (e.g., jet fuel)
	Comment (list all products transported):		
	What preventative measures are in place to reduce internal corrosion? (select one)	1	Inhibitor injection, internal coating, and/or operational measures(coalescers) plus internal coupon monitoring and pigging program (cleaning pigs at least twice a year)
		2	Cleaning pigs (at least 2 times per year) and internal corrosion monitoring (coupons or probes)
		3	Cleaning pigs or internal corrosion monitoring only
		4	No additional measures in place
		5	Not needed - product is not corrosive (0% water content)
	Comment:		
Incident and Failure History	*What is the human error incident history?* *Enter the number of human error incidents in the last 10 years:*		
	Describe incidents in detail, if any:		
	Any releases (past/present) on this pipeline segment, or similar segment, caused by failures of previously damaged pipe (dents and stress risers)? Enter number of non-seam related pressure cycle induced fatigue failures known to have occurred in the last 10 years (do not include failures for which conditions have been corrected):		
	Describe incidents in detail, if any:		

Form Name	Question	Answer
	Did pipeline section experience any external corrosion failures? Enter the number of in-service or test failures known to have occurred in the last 10 yrs (do not include failures for which conditions have been corrected; e.g. replaced entire section of pipe or installed new coating):	
	Describe failures in detail, if any:	
	Did pipeline section experience any internal corrosion failures? Enter the number of in-service or test failures known to have occurred in the last 10 yrs (do not include failures for which conditions have been corrected; e.g. replaced entire section of pipe or changed product):	
	Describe failures in detail, if any:	
In-Line Inspections	*What type of assessment was this in-line inspection?*	Prior assessment; Baseline assessment; Continuous assessment; Other
	Tool Type	High Resolution Magnetic Flux Leakage Tool; Low Resolution Magnetic Flux Leakage Tool; Transverse Flux Inspection Tool; Ultrasonic Tool; Ultrasonic Shear Wave Tool; Geometry Tool
	Inspection Date (mm/dd/yyyy)	
	Tool Name	
	Vendor Name	
	Final Report Date (mm/dd/yyyy)	
Pressure Tests	*What type of assessment was this pressure test?*	Prior assessment; Baseline assessment; Continuous assessment; State required testing; Other
	Pressure test date (mm/dd/yyyy)	
	Test pressure (psi)	
	Test duration (hours)	
	Were there any failures? (check if yes)	
	Describe failures, if any:	
Maintenance Units	*Field Unit Name:*	1 Lake Charles Area; Sour Lake Area; CASA, etc

Form Name	Question		Answer
	What is the quality of the training and OQ program? (select one)	1	Excellent - a formal OQ program exists that exceeds industry minimum standards, and all personnel is qualified to perform their tasks, including appropriate training, testing, and refresher training; minimum requirements for each pipeline job position are documented
		2	Good - a formal OQ program exists that meets minimum industry standards, most personnel is qualified and had appropriate training to perform their tasks; most job positions have adequately documented minimum requirements
		3	Adequate - OQ program meets only minimum regulatory requirements; not all job positions have adequately documented minimum requirements
		4	Inadequate - OQ program does not meet minimum regulatory requirements, as identified during regulatory inspections or internal reviews
	Comment:		
	What is the quality of the drug testing program? (select one)	1	Excellent - drug testing policy exceeds minimum regulatory requirements and is highly effective
		2	Good - drug testing policy meets minimum regulatory requirements and is effective
		3	Adequate - drug testing policy meets only minimum regulatory requirements
		4	Inadequate - drug testing policy does not meet minimum regulatory requirements, as identified during regulatory inspections or internal reviews
	Comment:		
	What is the quality of documentation program and recordkeeping? (select one)	1	Excellent - a formal documentation program exists that exceeds industry standards, all pipeline conditions, surveys, and activities are properly documented and all records are retained in both electronic and paper format; all records are readily available; current maps are available to operations personnel in paper and digital format (e.g. GIS) for 100% of the system

Form Name	Question		Answer
		2	Good - a formal documentation program exists, all of the pipeline conditions and activities are documented, records are retained and readily available; system maps are available to field personnel; pipeline GIS exists
		3	Adequate - a documentation program exists that meets only the minimum regulatory requirements, required pipeline conditions and activities are documented, required records are retained; system maps are available
		4	Inadequate - documentation program does not meet minimum regulatory requirements, as identified during regulatory inspections or internal reviews, not all pipeline conditions and activities are documented, few records are retained and readily available; maps are outdated or unavailable
	Comment:		
	What is the quality of the maintenance program? (select one)	1	Excellent - a formal maintenance program and schedule exists that exceeds industry standards, accurate data is collected through a formal Predictive Preventive Maintenance (PPM) approach and is maintained under document management system to ensure version control and ready access; all pipeline equipment is properly maintained according to its requirements
		2	Good - a formal maintenance program exists, pipeline equipment is properly maintained according to the industry standards and minimum regulatory requirements, some PPM concepts are employed
		3	Adequate - a semi-formal maintenance program exists that meets only minimum regulatory requirements, no PPM employed

Form Name	Question		Answer
		4	Inadequate - only informal maintenance program exists that does not meet minimum regulatory requirements, as identified during regulatory inspections or internal reviews, pipeline equipment is poorly maintained, not all required records are maintained
	Comment:		
Materials and Design	*Segment Length, ft*		=[EndCumSta-BegCumSta]
	Nominal Outside Diameter, in		Actual data from GIS used for risk calculations
	Nominal Wall Thickness, in		Actual data from GIS used for risk calculations
	Pipe Specification	1	NA - Actual data from GIS used for risk calculations
	SMYS	1	NA - Actual data from GIS used for risk calculations
	Longitudinal Seam	1	NA - Actual data from GIS used for risk calculations
	Seam Joint Factor	1	NA - Actual data from GIS used for risk calculations
	Design Factor	1	NA - Actual data from GIS used for risk calculations
	Calculated Internal Design Pressure (psig)		[((2*SMYS*NominalWallThick) / NominalOutsideDiameter) * DesignFactor * PipeLongitudinalSeamFactor] Actual data from GIS used for risk scoring and calculation made in Risk Model
	Calculated Maximum Operating Stress (as fraction of IDP)		MaximumOperatingPressure / [(2 * SMYS * NominalWallThick / NominalOutsideDiameter) * PipeLongitudinalSeamFactor] Actual data from GIS used for risk scoring and calculation made in Risk Model
	Calculated Normal Operating Stress (as fraction of Internal Design Pressure)		[Normal Operating Pressure / Internal Design Pressure] Actual data from GIS used for risk scoring and calculation made in Risk Model
Construction and	*What type of backfill and techniques were used for the pipeline segment?*	1	Quality backfill and proper backfill techniques were used; no soil movements

Form Name	Question		Answer
Manufacturing	*(select one)*	2	Improper backfill (e.g. containing large rocks or gravel) or poor backfill/pipe lowering/handling techniques were used during constructions; frequent soil movements
		3	Unknown backfill and/or pipe lowering techniques
		4	Not applicable - above ground pipe
	Comment:		
	What is the condition of the heat infected zone (HAZ) on the pipeline segment? (select one)	1	Selective seam corrosion on HAZ has caused in-service of test failure(s) on this or similar segment
		2	Selective seam corrosion on HAZ has been detected on this or similar segment, but no past failures occurred
		3	Selective seam corrosion on HAZ undetected by inspection or conditions/defects have been corrected for this segment
		4	Unknown condition of HAZ
		5	No HAZ (heat affected zone) - seamless or HF-ERW
	Comment:		
	What is the pipe segment's susceptibility to stress corrosion cracking (SCC)? (select one)	1	SCC has caused in-service of test failure(s) on this or similar segment
		2	SCC has been detected on this or similar segment, but no past failures occurred
		3	Favorable conditions exist for SCC to occur, but SCC undetected by inspection (crack tool or hydrotest) or conditions/defects have been corrected for this segment
		4	Favorable conditions exist for SCC to occur, no inspection performed (high stress >45% SMYS, high operating temperature >90°F, bituminous or tape coating, pipeline is older that 10 years)
		5	No conditions exist for SCC to occur (low stress <45% SMYS, ambient temperature, FBE or other high-quality coating, pipeline age less that 10 years)
	Comment:		

Form Name	Question		Answer
	Are there any known material defects on this pipeline segment?	1	Manufacturing defects, such as laminations, inclusions, blisters, scabs, or hard spots are found and caused failure on this or similar pipeline segment
		2	No material defects that can pose a threat to pipeline integrity exist as verified by Subpart E hydrotest
		3	Unknown manufacturing defects - no testing performed on the segment
	Comment:		
	What is the potential (susceptibility) for seam failure along this pipeline segment? (select one)	1	1 or more fatigue-related seam failures on this or similar segment, (either in-service or during baseline hydrotest conducted after 1/1/1996)
		2	Very Aggressive or Aggressive pressure cycles in a susceptible segment based on analysis per OPS TTO5;
		3	Not susceptible LF-ERW or lap welded pipe per OPS TTO5 engineering analysis
		4	No engineering analysis per OPS TTO5 to determine susceptibility of LF-ERW or lap welded pipe
		5	Not applicable - all seamless or HF-ERW pipe
	Comment:		
	Was a seam assessment performed on this pipeline segment? (select one)	1	ILI crack tool seam integrity assessment completed within last 5 years and all critical defects repaired
		2	Sub-part E hydrotest conducted after 1/1/1996 with no fatigue-related seam failures or failed sections were replaced
		3	No seam assessment performed
		4	Seam assessment not needed
	Comment:		
	What is the quality of the joints/welds along the pipeline segment? (select one)	1	Pipe joints were inspected by appropriate means (X-ray, ultrasound, etc.) and comply with industry standards
		2	Questionable welding practices, such as acetylene welds, were used, but weld anomalies did not cause failures in the last 5 yrs on this or similar segment

Form Name	Question		Answer
		3	Questionable welding practices, such as acetylene welds, were used; undercut welds or other weld anomalies are discovered on this or similar segment and caused failures in the last 5 yrs
		4	Unknown/questionable joint inspection methods, but no girth weld failures in the past
	Comment:		
	Do wrinkle bends and/or buckles or other construction defects exist along the pipeline segment?	1	Wrinkle bends/buckles or other construction defects are present and caused failure in the past on this or similar segment
		2	Wrinkle bends/buckles or other construction defects are present, but did not cause failures in the past
		3	No wrinkle bends/buckles or other construction defects exist; or defects have been corrected on this segment
		4	Unknown
	Comment:		
Traffic Loading	*Is this pipeline segment subject to traffic loading conditions?*	1	Pipeline is subjected to traffic loading conditions
		2	No traffic loading conditions exist (adequate measures in place)
		3	Not applicable (not a road crossing)
	Comment:		
Spans and Above Ground Pipe	*Type of above-ground segment (do not include above-ground sections associated with pipeline equipment or spans that are less than 50 ft):*		Span; Crossing; Above-ground pipeline section
	Span/above-ground section description or crossing name:		
	Length, ft		=[EndCumSta-BegCumSta]
	Type of Support	1	Unsupported or improperly supported span or suspension from bridge
		2	Properly supported span or supports not needed (short length)
		3	Unknown support - additional investigation needed to determine if supports are adequate
	Does the span have a casing? (check if yes)		
	Comments:		

Form Name	Question		Answer
	What atmospheric exposures exist on the pipeline segment? (select one)	1	Ground/air interface
		2	Above ground casings/supports/hangers/insulation
		3	Splash zone
	What are the atmospheric conditions for the pipeline segment? (select one)	1	Low humidity and low temperature
		2	Chemical and low humidity
		3	High humidity and high temperature
		4	Marine, swamp, coastal
		5	Chemical and high humidity
		6	Chemical and marine
	What is the quality of atmospheric coating for the pipeline segment? (select one)	1	Excellent condition (e.g. less than 5 yrs old)
		2	Good condition (e.g. 5-10 yrs old, no unmitigated defects)
		3	Fair condition (e.g. older than 10 yrs)
		4	Poor condition or no coating
		5	Unknown
	Is there evidence of atmospheric corrosion on the pipeline segment?	1	Atmospheric corrosion anomalies have been detected on this or similar pipeline segment
		2	Undetected or conditions leading to atmospheric corrosion have been corrected for this segment
		3	Unknown
	Did the pipeline section experience any atmospheric corrosion failures? Enter the number of failures known to have occurred in the last 10 yrs (do not include failures for which conditions have been corrected):		
	Describe conditions and failures (if any) in detail:		
Depth of Cover	*Select type of pipeline location to display minimum depth of cover requirements:*	1	Industrial, commercial, and residential (normal excavation) - 36"
		2	Industrial, commercial, and residential (rock excavation) - 30"
		3	Crossings of inland bodies of water with a width of at least 100 ft (normal excavation) - 48"

Form Name	Question		Answer
		4	Crossings of inland bodies of water with a width of at least 100 ft (rock excavation) 18"
		5	Other area, normal excavation - 30"
		6	Other area, rock excavation - 18"
	Does the amount of cover for the selected location type comply with minimum regulatory requirements? (select one)	1	Exceeds minimum regulatory requirements by at least 12 inches
		2	Meets minimum regulatory requirements plus warning mesh, warning tape, or other measures to prevent TPD are used
		3	Meets minimum regulatory requirements, no additional measures
		4	Does not meet minimum regulatory requirements, but other measures are in place, such as concrete cover of at least 4 inches, casing, or warning mesh
		5	Does not meet minimum regulatory requirements, no additional measures are used
		6	Not Applicable - above-ground pipe
		7	Unknown
	Comments (also enter date and results of DOC survey, if applicable):		
Activity Level	*What is the excavation activity level in the area of the pipeline segment? (select one)*	1	High activity level - high population density; frequent construction activities; high volume of one-calls (>2/wk), rail or roadway traffic, many buried utilities nearby, possible damage by farming equipment
		2	Medium activity level - medium population density, few buried utilities, infrequent construction and agricultural activities
		3	Low activity level - rural areas (no possibility of damage due to farming), virtually no one-calls (<10/yr), no harmful activities in the area
		4	No third-party activity - no chance of any digging or other harmful third-party activities

Form Name	Question	Answer
	What is the third-party damage incident history on this pipeline segment? Enter the number of third-party incidents (dents, releases, or near-misses) known to have occurred in the last 10 yrs:	
	Describe activity level and incidents (if any):	
Pipeline Right Of Way	*What is the right-of-way (ROW) condition for this pipeline segment? (select one)*	1 Excellent - clear and unencumbered ROW; route is clearly indicated; signs and markers are clearly visible from any point on ROW or from above; signs at all road crossings, railroads, ditches, water crossings; all changes of direction are marked; air patrol markers are present
		2 Good - clear route, well marked, signs and markers meet minimum regulatory requirements
		3 Average - ROW not uniformly cleared, more markers are needed for clear identification at roads, railroads, ditches, and water crossings
		4 Below average - ROW is overgrown in vegetation in some places, ground is not always visible from the air or there is no clear line of sight from ground level; indistinguishable as pipeline ROW in some places; poorly marked
		5 Poor - indistinguishable as pipeline ROW; inadequate or no markings
		6 Unknown
	Describe ROW condition:	
One Call System	*What is the effectiveness of one-call system? (select one)*	1 One-call is not mandated by law
		2 One-call is mandated by law, but is poorly advertised/not strictly enforced and/or not used by community
		3 One-call is mandated by law, widely advertised, strongly enforced, and well known and used in community
		4 One-call is not needed (e.g. pipeline is within company's facility)
	Call Center name:	
	Comments:	

Form Name	Question		Answer
Damage Prevention	*What is the ROW patrol frequency for pipeline segment? (select one)*	1	Exceeds minimum regulatory requirements
		2	Meets minimum regulatory requirements
		3	Less than minimum regulatory requirements
		4	Unknown
	Enter frequency:		
	Patrol type:	1	Aerial; Vehicle; Foot
	What is the quality of line locating procedures for pipeline segment? (select one)	1	Excellent - formal, documented procedures in place that exceed minimum regulatory requirements, comply fully with API 1166, and include all of the following: procedures to receive, record, and respond to notifications, comprehensive marking and locating procedures and training, on-site inspections during the excavations, accurate maps and records showing pipeline locations, inspection of pipeline facilities after excavation
		2	Good - written procedures and training in place to receive, record, and respond to notifications, mark and locate the line; pipeline maps are generally accurate and up-to-date; procedures meet regulatory requirements, but are not always clear or well documented; procedures not fully compliant with API 1166
		3	Adequate - written procedures that meet only minimum requirements are in place to receive and respond to notifications, mark and locate the line; pipeline maps are generally accurate and up-to-date; no written procedures for on-site inspection during and/or after excavation
		4	Inadequate - no formal written procedures and/or training in place to receive, record, and respond to notifications, mark and locate the line; pipeline maps are outdated; procedures do not meet regulatory requirements, but are not always clear or well documented; procedures not fully compliant with API 1166
		5	Not applicable - no third-party excavation activities

Form Name	Question		Answer
	Comments:		
	What is the quality of a Public Awareness (PA) program for the pipeline segment? (select one)	1	Excellent - written PA program exceeds minimum regulatory requirements, is API 1162 compliant, has been implemented and is highly effective
		2	Good - written PA program is API 1162 compliant and meets minimum regulatory requirements
		3	Adequate - written PA program is API 1162 compliant and meets minimum regulatory requirements, but not yet fully implemented
		4	Inadequate - no formal PA Program exists or it does not meet minimum regulatory requirements, as identified during regulatory inspections or internal reviews
		5	Not applicable - PA program is not needed because of restricted access or no population
	Comments:		
Soil Corrosivity	*What is the corrosivity of the soil or pipeline environment? (select one)*	1	Low corrosivity (low moisture) and/or high soil resistivity (>15,000 ohm-cm) and non-corrosive environment
		2	Medium soil corrosivity (e.g. farmlands) and/or soil resistivity 1,000-15,000 ohm-cm; environment can be corrosive under certain conditions
		3	High soil corrosivity (e.g., very high moisture, swamp, or marsh) and/or low soil resistivity (<1,000 ohm-cm); very corrosive environment
	Is there evidence of microorganisms? (select one)	1	Sulphate-reducing bacteria (SRB) and/or microbiologically influenced corrosion (MIC) detected
		2	No evidence of MIC or SRB, as verified by testing
		3	Unknown soil conditions (no testing performed)
	Describe the soil conditions and soil surveys results, if applicable:		

Form Name	Question		Answer
Coating Type	*What is the coating type for the pipeline segment? (select one)*	1	NA – Coating information from GIS used in risk scoring
	Comment:		
Coating Condition	*What is the current coating condition? (select one)*	1	Excellent condition - less than 20 yrs old and no reported defects
		2	Good - more than 85% of exposed coating is tightly adherent and intact
		3	Fair - 50-85% of exposed coating is tightly adherent and intact
		4	Poor - < 50% of coating is tightly adherent and intact, with known multiple areas of severe disbonding, cracking, or pitting
		5	Unknown
	Is this an original coating? (check if yes)		
	What is the age of coating? (enter year installed or replaced)		
	Summarize coating conditions, results of coating surveys (DCVG), or visual inspections		
Buried Casings	*Casing, Casing Condition -1,and Casing Condition-2 factors*	1 2 3 4 5	*NA - Casing information from GIS and current ILI data used for risk model scoring.*
Cathodic Protection	*How adequate is the design of the CP system? (select one)*	1	All potential interference sources in the vicinity of the pipeline are monitored directly by test leads; all casings are monitored; test lead spacing is no greater than 1 mile

Form Name	Question		Answer
		2	Test leads are spaced at distances of 1 to 2 miles apart; there may be some potential interference sources that are not monitored
		3	Test lead spacing is 2 miles or greater, potential interference sources are not monitored
		4	None - no CP system
	How effective is the CP system? (select one)	1	CP effectiveness verified by CIS on/off survey (meets -850 mV criteria) conducted at least every 5 yrs and annual pipe-to-soil readings at test locations
		2	CP effectiveness could not be verified by CIS on/off survey, but verified by CIS polarization survey (100 mV shift) conducted at least every 5 yrs and annual pipe-to-soil readings at test locations
		3	Annual pipe-to-soil readings at test locations only; good pipe-to-soil potentials
		4	Ineffective CP system - did not pass 100 mV shift criteria; rectifier out of service, depleted anodes, corroded test leads, CP shielding to poor coating, no CP for >1 year, etc.
	Number of years that the system was operating without CP:		
	Select the CP system type:	1	Galvanic; Impressed Current
	Comment:		
AC Interference	*Does AC interference present a threat to this pipeline segment? (select one)*	1	AC power is nearby, no preventative actions are being taken
		2	AC source is nearby, but preventative measures are being used to protect the pipeline or AC interference is not a threat as confirmed by surveys
		3	No AC power within 1000 ft of the pipeline
		4	Unknown
	Comment:		
DC Interference	*Does DC interference present a threat to this pipeline segment? (select one)*	1	DC-related interference caused by other buried metal/electric rail is possible, no mitigative measures in place
		2	Potential for DC interference, but mitigation in place, such as interference bonds, isolators, and test leads

Form Name	Question		Answer
		3	No evidence of DC currents
		4	Unknown
	Comment:		
External Corrosion	*Is there evidence of external corrosion on the pipeline segment?*	1	NA - Actual data from recent ILI run used for risk calculations
		2	NA - Actual data from recent ILI run used for risk calculations
		3	Unknown conditions - No ILI
	Comment:		
Internal Corrosion	*Is there evidence of internal corrosion on the pipeline segment?*	1	NA - Actual data from recent ILI run used for risk calculations
		2	NA - Actual data from recent ILI run used for risk calculations
		3	Unknown conditions - No ILI
	Comment:		
Valve or Valve Station	*Valve (valve station) name or location:*		
	Valve type (select one):	1	Gate; Ball; Check; Plug
	Valve make (select one):	1	WKM;Grove;M&J;Nordstrom;Wheatley;Daniel;Unknown;Foster;Crane;WOM;PBV
	Valve pressure rating:		
	Is this a motor operated valve? (check if yes)		
	Is this a buried valve? (check if yes)		
	Does the valve have a secondary containment? (check if yes or if product is HVL)		
	Atmospheric exposure:		Ground/air interface
	Atmospheric condition (select one):	1	Low humidity and low temperature
		2	Chemical and low humidity
		3	High humidity and high temperature
		4	Marine, swamp, coastal
		5	Chemical and high humidity
		6	Chemical and marine
	Comments:		
	Atmospheric coating condition (select one):	1	Excellent condition (e.g. less than 5 yrs old)
		2	Good condition (e.g. 5-10 yrs old, no unmitigated detects)
		3	Fair condition (e.g. older than 10 yrs)

Form Name	Question		Answer
		4	Poor condition or no coating
		5	Unknown
	Comments (e.g. year coating applied):		
	What is the potential for damage due to vehicle impact or vandalism? (select one)	1	Very low potential for damage - valve(s) are located inside company's property and are protected from company vehicle impact and third party damage/vandalism
		2	Low potential for damage - valve(s) are more than 200 feet from road or other measures in place to reduce vehicle impact (railing/structure/ditch) and third party intrusion/vandalism (security/fence/restricted access)
		3	Medium potential for damage - valve(s) are not protected from company vehicles or protection measures in place are not sufficient to prevent vehicle impact or third party intrusion/vandalism
		4	High potential for damage - valve(s) are less than 200 ft from vehicles and/or are easily accessible to public
		5	No above-ground pipe or components exist
	Comments:		
	What is the valve condition?	1	Good - valve seals (packing, gaskets, O-rings) and other components are properly maintained; valve is being fully stroked periodically; similar valves did not experience failures in the past
		2	Average - valve seals (packing, gaskets, O-rings) or other components present potential for valve failure; similar valves experienced failure(s) in the past
		3	Poor - valve is not properly maintained
	Comment (e.g. year valve installed or replaced):		
	Number of flanges associated with the valve or valve station:		
	Flange ANSI rating:		
	Flange gasket maintenance and failures (select one):	1	Flange gaskets are compatible and properly maintained; similar flanges did not cause failures in the past

Form Name	Question		Answer
		2	Flanges or flange gaskets present potential for failure; similar flanges experienced failures in the past
		3	No Flanges
	Comment:		
Pump Station	*Pump Station name or location*		
	Number of pumps		
	List pump type(s) and horsepower:		
	Number of meters		
	Number of sumps		
	Does the pump station have a secondary containment? (check if yes or if product is HVL)		
	Do the pump(s) have leak detection? (check if yes)		
	What is the condition of the pumps and pump station equipment (based on the worst-case component)?	1	Excellent - pump seals, auxiliary tubing, and other associated equipment is in perfect condition (less than 10 years old) and properly maintained; pump station never experienced equipment related failures
		2	Good - pump seals, auxiliary tubing, and other associated equipment is in good condition (10-20 years old) and properly maintained; pump station did not experience equipment related failures in the last 10 years
		3	Average - pump seals, auxiliary tubing, and other associated equipment is in average condition (older than 20 years) and properly maintained; pump station has experienced 1-2 equipment related failures in the last 10 years
		4	Poor - pump seals, auxiliary tubing, and other associated equipment is not properly maintained and present potential for failure; pump station has experienced more than 2 equipment related failures in the last 10 years
	Comments:		
	Number of flanges within pump station (estimate):		
	Flange ANSI rating:		

Form Name	Question		Answer
	Flange gasket maintenance and failures:	1	Flange gaskets are compatible and properly maintained; similar flanges did not cause failures in the past
		2	Flanges or flange gaskets present potential for failure; similar flanges experienced failures in the past
	Comment:		
Stopple	*Number of stopples or buried flange connections:*		
	Flange ANSI rating:		
	Flange gasket maintenance and failures:	1	Flange gaskets are compatible and properly maintained; similar flanges did not cause failures in the past
		2	Flanges or flange gaskets present potential for failure; similar flanges experienced failures in the past
		3	No Flanges
	Comment:		
Dense Residential Areas	*Densely populated residential area, hospital, school, or other area where people congregate, even if already in HPA or OPA? (check if yes)*		
	Describe area:		
National Ecological Resources	*National Parks, National Wildlife Refuges, National Wilderness Areas, National Forests, and other cultural resources and sensitive environmental resources, other than USAs? (check if yes)*		
	Describe area:		
Water Resources	*Shore/intertidal areas, shallow waters, marshes, wetlands, fish hatcheries, lakes, rivers, or drinking water intakes, other than ECO/DW USAs? (check if yes)*		
	Describe area:		
Farms and Agricultural Lands	*Special farms and high-value agricultural lands? (check if yes)*		
	Describe area:		

ATTACHMENT III – DATA ELEMENTS FOR PIPELINE INTEGRITY MANAGEMENT PROGRAM

The following information should be collected (as available) for all pipeline assets that are being added to the Integrity Management Program:

Pipeline Attribute Data

Pipe Length
Engineering Stationing
Pipe wall thickness
Diameter
Seam type and joint factor
Manufacturer (if known)
Manufacturing date (if known)
Associated Equipment (valves, pumps, meters, sumps, etc.)

Construction Data

Year of installation
Coating type
Bending method
Depth of cover
Number of crossings/casings
Pressure test (original)
Field coating methods
Soil, backfill
Inspection reports
Cathodic protection installed
Joining method, process, and inspection results

Operational Data

Product type and quality
Internal/external corrosion monitoring
Flow rate
Maximum operating pressure (MOP)
Normal operating pressure (NOP)
System design pressure

Operating stress level (% SMYS)
CP (Cathodic Protection) system performance
Pressure fluctuations (cycles)
Leak detection
Monitoring and control
Use of SCADA
Cleaning pigs
Repair history

Inspection Data

Pressure tests
In-line inspections
Bell hole inspections (exposed pipe reports)
CP inspections (CIS)
Coating condition and inspections (DCVG)
Casing monitoring
Right-of-way inspections
Encroachments
Span inspections
Underwater crossing inspections
MIC detected (yes, no, or unknown)
SCC detected (yes, no, or unknown)
Audits and internal reviews

Incident and Failure History

Number of reportable leaks/failures
Third party damage (excavation) incident history
Vandalism
Operational errors or incidents (reportable under § 195.55)

Doc # **IMP-PR0017**	**Pipeline Integrity Management**	
	Doc. Title: **FACILITIES WITHOUT BREAKOUT TANKS RISK ASSESSMENT PROCEDURE**	**CITGO Pipeline Company** Tulsa, Oklahoma
Reviewed By: C. Fairless Pipeline Integrity Manager	Approved By: K. Lloyd Manager Engineering, Pipeline Compliance & Control	Approved By: K. Powers General Manager, Terminals and Pipelines
Original Release Date: 8/21/2008	Revision 0 Rev. Release Date:	Page 1 of 19

1 PURPOSE

1.1 The purpose of this document is to describe the standardized process in the Integrity Management Program for analyzing risks and threats to pipeline facilities (specifically for those without breakout tanks) and determining the consequences of a potential release in any High Consequence Areas (HCA) impacted by those facilities. Associated preventive and mitigative measures will also be identified, evaluated and implemented, as appropriate.

2 SCOPE

2.1 This procedure applies to all liquid pipeline facilities without breakout tanks owned by CITGO Pipeline Company or operated by CITGO Pipeline Company that could affect an HCA.

2.2 This review process will be implemented every five years for each facility without tanks in coordination with pipeline general assessments.

3 RELATED DOCUMENTS

3.1	IMP-PL0001	Integrity Management Plan for DOT Part 195 and Texas Rule 8.101
3.2	IMP-PL0004	Risk Segment Identification Procedure
3.3	IMP-PL0008	Facilities (With Breakout Tanks) Risk Assessment Procedure
3.4	IMP-PR0013	Threat Identification and Risk Assessment Procedure
3.5	API 353	Managing the Risk of Liquid Petroleum Releases

3.6	API 1160	Managing System Integrity for Hazardous Liquid Pipelines
3.7	EPP-0001.0	EWR Procedure

4 DEFINITIONS

4.1 EWR – Engineering Work Request

4.2 Facility – Any aboveground area of land containing one or more pieces of equipment such as; meters or meter provers, pumps, piping manifolds, or breakout tanks connected to a regulated pipeline. A valve, a tie-in location with valves, or a scraper trap on the ROW does not constitute a Facility.

4.3 High Consequence Area (HCA) – As defined by the Department of Transportation Section 195.450 and includes "Commercially Navigable Waterways," "High Population Areas," "Other Population Areas," and "Unusually Sensitive Areas" (USA).

4.4 Pipeline Risk Segment – A portion of a Pipeline Section that intersects an HCA or could affect a HCA by any of the following methods: (1) Direct intersection with an HCA or NHD stream, (2) ¼ mile buffer around an HCA for hazardous liquid lines, (3) 5 mile buffer around an HCA for highly volatile liquid lines, or (4) Land or water transport of a release to an HCA or NHD stream. A Pipeline Section may have multiple risk segments.

4.5 Pipeline Section – Pre-defined portion of a pipeline that can be internally inspected, from launching device to receiving device (piggable section), or a portion of a pipeline that can be hydro-tested.

4.6 Pipeline System – A "System" is a portion of CITGO's overall pipeline operations, separate in terms of service to different geographical areas and defined as Lakemont Pipeline System, West Shore Pipeline System, CASA Pipeline System, and Gulf Coast Pipeline System.

4.7 Risk Assessment – Systematic process identifying the potential hazards presented during facility operation and likelihood and consequences (or impacts) of incidents. Elements include:

- Identifying potential events or conditions that could threaten system integrity.

- Evaluating likelihood of failure and consequences.
- Ranking risk and identifying specific threats that influence or drive the risk.
- Identifying prevention and mitigation options.

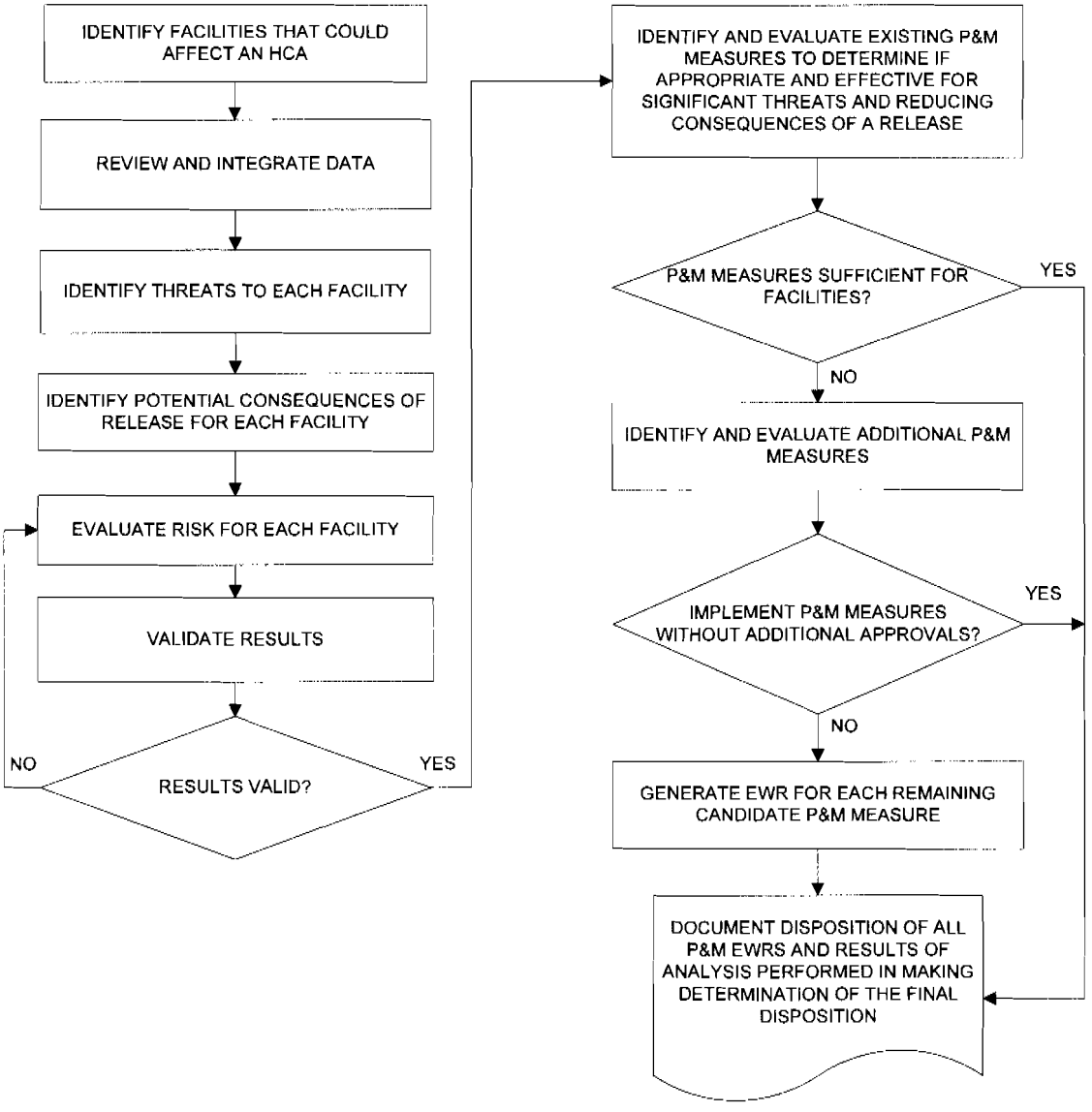
5 RESPONSIBILITIES AND TRAINING

5.1 The Pipeline Integrity Manager and/or the Integrity Engineer is responsible for overseeing Facility Risk Assessment analyses and are trained to understand and apply the directions in this procedure.

5.2 The Integrity Engineer and the Area Supervisor are responsible for ensuring that the preventive and mitigative measures analysis is properly analyzed and documented.

6 PROCESS FLOW DIAGRAM

FACILITY RISK ASSESSMENT



7 PROCEDURE

Note: For the purposes of this procedure, the term Facility or Facilities, unless otherwise stated, is referring to those locations without breakout tanks.

7.1 Identify Facilities that Could Affect an HCA

7.1.1 The Integrity Manager is responsible for updating the list of Facilities on CITGO owned and operated pipelines and are identified as:

- CASA System (Texas):
  - Nueces Station
  - Refugio Station
  - Victoria Delivery
  - Victoria Station
  - Yoakum Station
  - Luling Station
  - San Antonio Delivery
- Gulf Coast System:
  - Mont Belvieu Station (Texas)
  - Lakemont Pecan Grove Facility (Louisiana)
- West Shore System:
  - Hammond
  - Blue Island Station
  - Bell
  - Romeo
  - Busse
  - Lindenhurst
  - Mitchell Field
  - Elkhart Lake
  - Green Bay
  - Fox River
  - East Chicago Station
  - Canal Junction
  - Bensenville
  - Hampshire
  - Des Plaines
  - Rockford Airport Delivery
  - Rockford

- Madison
- O'Hare Delivery
- Lemont
- Argo
- Harlem

7.1.2 In addition to updating the Facility List, the Integrity Manager oversees the documentation of the following additional considerations for each facility:

- Proximity to HCAs

- Potential release volumes and release points and pathways - Release volumes and points at the above Facilities are handled as standard pipeline release volumes and pipeline release point spacing as described in IMP-PR0004, "Risk Segment Identification Procedure." See explanation of release point spacing and volume considerations (Para. 6.4.2.5). See also IMP-PL0001, Paragraph 6.6.1.4 and 6.6.1.5. Pathways are also analyzed as part of overland spread from a pipeline point release.

7.2 Review and Integrate Data

7.2.1 The Area Supervisor gathers facility data in preparation for evaluating potential risks to pipeline facilities. Reviews are done in conjunction with pipeline integrity testing. See API 1160 Section 12 for more details about the following data types:

- Incident History
- Design Data
- Corrosion Data
- Security Information
- Information About the Physical Environment of the Facility
- Population or Environmental Concerns Near the Facility (HCAs)
- Information about the Operating Characteristics of the Facility
- Emergency Response Equipment and Capabilities

7.3 Identify Threats to Each Facility

7.3.1 Data gathering and reporting is done by the Area Supervisor responsible for facilities being evaluated in consultation with other support personnel as needed (Integrity Engineer, Area Corrosion Technician, etc.). This information is recorded on Form IMP-FM0008 (see Appendix).

7.3.2 General threats for all facilities include (but are not limited to) the following categories and the current and historical data about these threats are part of the risk evaluation process as applicable. Any releases as a result of these are checked on Form FM0008:

7.3.2.1 External Corrosion

- Piping and supports
- Equipment

7.3.2.2 Internal Corrosion

- Piping
- Equipment

7.3.2.3 Manufacturing Defects

- Fittings, pump casing casting defects
- Incorrect elastomers supplied leading to failures

7.3.2.4 Welding/Fabrication Defects

- Girth weld failure due to poor welding methodology or quality control
- Pipe fabrication errors leading to over-stresses on equipment

7.3.2.5 Equipment

- Cathodic protection deficiencies
- Pump seal failure
- Gasket failure
- Leaking packing on valves
- Faulty or non-existing over-pressure protection

- Insufficient preventive maintenance
- Faulty control valves, motor operated valves, relief valves/surge protection valves
- Electrical starter, transformer, grounding, and communication system malfunctions
- Leaking underground storage tanks or sumps

7.3.2.6 Third Party Damages

- Inadequate security, industrial sabotage
- Traffic damage and lack of protective barriers
- Vandalism

7.3.2.7 Incorrect Operations

- Pipe surges or vibration causing fatigue
- Sump overflows
- Incorrect valve lineup or operation
- Poor communication with pipeline control center
- Emergency equipment availability and maintenance
- Poor overall facility maintenance
- Inadequate containment capacity
- Inadequate thermal expansion protection
- Insufficient Training on the following:
  - Operating equipment
  - Activities and Facility Condition documentation
  - General Safety, Operating and Maintenance Procedures
  - Abnormal Operating Conditions
  - Fire protection
  - Fuel Spills
  - Emergency response drills
  - Accident prevention
  - Hazard analysis and communication

7.3.2.8 Weather/Outside Forces

- Tornadoes, Hurricanes
- Flooding
- Lightning
- Frost heave
- Hot or Cold temperatures
- Earth movement (subsidence, landslides, blasting, erosion, expansive soil movement)

7.4 Identify Potential Consequences (Leak Impacts) of Release for each Facility

7.4.1 For all facilities being evaluated, the Integrity Manager or designee evaluates the maximum release volume and potential consequences of a release from the facility just as if it would be a pipeline point release.

7.4.2 Each Facility is looked at to determine spill volume. An analysis of drainage plans are performed to determine potential release points and how they could direct spilled volumes from the site's boundaries and in what direction. Product characteristics, volume, product dispersion (pathways, soil permeability, slope, etc.), HCA receptors, number of release points, and direction of flow are factors in evaluating the consequences of a release.

7.5 Evaluate Risk for Each Facility

7.5.1 Risks for Facilities are assessed as if they were a point on a pipeline at that specific location. (See Procedure IMP-PR0013 "Threat Identification and Risk Assessment Procedure").

7.5.2 The Integrity Manager reviews information for each of the eight (8) threats listed in this procedure (as a minimum) as they apply to an individual Facility.

7.5.3 When data required to evaluate a particular threat is missing, conservative assumptions are used when performing the risk assessment.

7.5.4 The following are considered in order to exclude a threat from a facility:

- There is no history of a threat impacting the particular facility.
- The threat is not supported by applicable industry data or experience.
- The threat is not supported by like/similar analyses.
- The threat is not applicable to system operating conditions.

7.5.5 The Integrity Manager or designee also reviews the types of HCAs potentially impacted for each facility.

7.5.6 Factors considered in evaluating consequences include the following:

- 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 (hazards and dispersion characteristics)
- Amount of product that could be released

7.5.7 Refer to the Appendix, Form IMP-FM0008. Area Supervisors are responsible for performing a survey of each Facility under their jurisdiction every five years and completing Form FM0008. The form is then sent to the Pipeline Integrity Manager for review, actions taken as needed, and placed into the network server for reference and file storage.

7.6 Validate Results

7.6.1 The Integrity Manager and/or the Integrity Engineer reviews the risk assessment results recorded on FM-0008 to ensure that the results are logical and consistent with CITGO's and the industry's experience.

7.7 Identify and Evaluate Existing P&M Measures for Each Facility to Determine if Appropriate and Effective for the Significant Threats and if Appropriate and Effective for Reducing the Consequences of a Release

7.7.1 The Integrity Engineer and the Area Supervisor examines forms IMP-FM0008 and IMP-FM0015, List of Existing P&M Measures-Pipeline Facilities, to identify existing and suggested preventive and mitigative

measures for each facility evaluated.

7.7.2 The Integrity Engineer and the Area Supervisor discuss and agree whether the existing P&M measures are appropriate and effective for the threats applicable to the Facility and/or in reducing the consequences of a release.

7.7.3 The Integrity Engineer and the Area Supervisor evaluates whether a range of improvements from incremental to significant may be cost effective additions to the existing P&M measures.

7.8 P&M Measures Sufficient for Facilities?

7.8.1 If the Integrity Engineer and the Area Supervisor determines that the current P&M measures in place at existing facilities are sufficient to protect the HCAs impacted by those facilities, this is documented on FM-0008

7.8.2 If no, the P&M measures are not sufficient to protect the HCAs or if it is not known if the P&M measures are sufficient to protect the HCAs, the Integrity Engineer and the Area Supervisor continues to the next step to identify and evaluate additional P&M measures.

7.9 Identify and Evaluate Additional P&M Measures

7.9.1 The Integrity Engineer and the Area Supervisor generate a list of candidate Facility P&M improvement measures, or recommends that possible P&M improvement measures be further studied by Pipeline & Terminals Engineering, or both.

7.9.2 Enhancement to existing P&M measures includes the following categories (See API 1160 Section 12):

7.9.2.1 Inspections: API 570 is a guiding document for developing CITGO's inspection strategy. Periodic visual inspections of the facility by Area Supervisors are performed. An on-site visual inspection includes the following:

- Obvious leaks or indications of a leak such as stains around valves or flanges or stained soil or gravel.
- Inspection of instrument wells for sign of leakage at the tubing connection or corrosion of piping or auxiliary piping.
- Evidence of excessive vibration of pipe or auxiliary piping that could result in fatigue related failures.
- Sumps for product levels.
- Loose connections of threaded or flanged fittings.
- Oil/water separators.
- Product sheens on retention ponds.
- Condition of security fencing, signs of vandalism or unauthorized access.
- Piping air-soil interface and pipe at support corrosion.
- Etc.

7.9.2.2 Routine Maintenance of Protective Devices: Facilities have a broad range of protective devices, including pressure regulators, such as control valves and pressure switches, product level gauges, switches and alarms. These devices are periodically inspected, calibrated, and tested to ensure they perform their intended function. In evaluating the existing protective devices the following is considered:

- Is the type or style of existing protective devices adequate for the intended function(s)? Are they reliable? Would a different type be more appropriate?
- Are additional protective devices needed?

7.9.2.3 Corrosion Control: Cathodic protection systems must be maintained. Results of pipe inspection reports are evaluated by a Corrosion Contractor and/or Corrosion Engineer to determine if cathodic protection systems need improvement. External equipment and piping coating inspections are evaluated to determine if coating systems need maintenance.

7.9.2.4 Leak Detection: Potential mitigative actions to detect releases and reduce consequences include:

- Hydrocarbon sensing cables/devices

- Gas sensors to detect combustible vapors
- Integrity Testing (leak test/standup test, Inline pig inspection, hydrostatic test, pneumatic test, tracer chemicals)

7.9.2.5 Emergency Response Capability: Potential mitigative actions to improve emergency response capabilities to reduce the consequences of releases include:

- On-site spill containment equipment and material
- Pre-determined product containment recovery sites
- Participation in joint response groups
- Emergency response training including participation in periodic emergency drills

7.9.2.6 Facility Design Considerations: When new facilities are constructed or modifications to existing facilities are made, improved design features are incorporated or considered such as:

- Make piping accessible for inspection by limiting the amount of buried piping.
- Avoid buried flanged or threaded connections.
- Avoid low flow and dead legs.
- Minimize the number of small taps which are subject to damage.
- Route surface drainage through underflow retention ponds.

7.9.2.7 Routine Operating Procedures (O&M Procedures): A review and root cause analysis of any incidents may reveal the need for changes to the O&M procedures.

7.10 Implement P&M Measures Without Additional Approvals?

7.10.1 If yes, the P&M measure is implemented locally without further approval, then the facility manager secures the necessary resources for the new P&M measure and proceeds with implementation. Add new re-occurring P&M measures to IMP-FM0015, List of Existing P&M Measures-Facilities. Track any 1-time P&M measures using IMPACT system.

7.10.2 If no, the preventive and mitigative measure needs additional approvals, continue to the next step to generate an Engineering Work Request.

7.11 Generate EWR for each Remaining Candidate P&M Measure

7.11.1 The Area Supervisor responsible for each facility generates an Engineering Work Request (EWR) for each candidate Facility P&M improvement measure that needs additional study and approval.

7.11.2 The Area Supervisor submits the EWR for approval and entry into the EWR process, as described in EPP-0001.0, EWR Procedure.

7.12 Document Disposition of all P&M EWR's

7.12.1 Document the disposition of all P&M Engineering Work Requests using IMPACT system

8 RECORDS

8.1 IMP-FM0015 List of Existing P&M Measures-Facilities

8.2 P&M Engineering Work Requests for Facilities

8.3 IMP-FM0008 Facility Risk Evaluation, Facilities Without Breakout Tanks

APPENDIX

FACILITY RISK EVALUATION
Facilities without Breakout Tanks

GENERAL INFORMATION:

Name of Facility:	
Date of Report:	
Contributors to Report:	
Pipeline Identification Number(s)	1: Size: 2: Size: 3: Size:

HCA IMPACTS:

A release can impact what HCAs? (check all that apply)	☐ High Population ☐ Other Population ☐ CNW ☐ Drinking Water ☐ Ecological Area

RELEASES:

Has there been a release in the past 10 years?	☐ Yes ☐ No		
If there was a release(s), when did it (they) take place:	1: 2: 3:		
Cause of Release -(please check appropriate box(s)	Incident **#1**	Incident **#2**	Incident **#3**
	☐Ext, Corrosion ☐ Int. Corrosion ☐ Microbial ☐ Manufact. Def. ☐ Welding Defect ☐ Fabrication Def. ☐ Equipment ☐ 3rd Party ☐ Incorrect Operations ☐ Weather/Forces ☐ Other:	☐Ext, Corrosion ☐ Int. Corrosion ☐ Microbial ☐ Manufact. Def. ☐ Welding Defect ☐ Fabrication Def. ☐ Equipment ☐ 3rd Party ☐ Incorrect Operations ☐ Weather/Forces ☐ Other:	☐Ext, Corrosion ☐ Int. Corrosion ☐ Microbial ☐ Manufact. Def. ☐ Welding Defect ☐ Fabrication Def. ☐ Equipment ☐ 3rd Party ☐ Incorrect Operations ☐ Weather/Forces ☐ Other:
Add explanation for release(s)if more details are known:			
Additional Information:			

FACILITY INFORMATION:

Leak Detection Capabilities	Hydrocarbon sensing cables/devices: ☐ Yes, ☐ No, Comments: Gas Sensors to detect combustible vapors: ☐ Yes, ☐ No, Comments: Other Leak Detection Devices: Integrity Testing: ☐ Inline Pig Inspection, ☐ Hydrostatic Test, ☐ Pneumatic Test, ☐ Other, Comments:
Security	Lighting: ☐ Adequate ☐ Inadequate ☐ Other
	Entrance Security: ☐ Adequate ☐ Inadequate ☐ Other
	Surveillance: How often
Physical Environment	Subject to Weather Impacts: ☐ Flooding, ☐ Earthquakes, ☐ Tornadoes, ☐ Hurricanes, ☐ Lightning Population or Environmental concerns adjacent to Facility: Does the terrain surrounding the Facility act as a conduit to High Consequence Areas? Are there drainage systems and streams near the Facility acting as a conduit to High Consequence Areas? Product Characteristics: Products received/shipped at Facility: ☐ Liquids, ☐ Gasses, Comments
Dead Legs/Low Flow Segments	☐ None Exist ☐ One or more exists

An on-site visual inspection included the following observations:

Any evidence of notable External Corrosion on piping, supports or equipment?	☐ Yes, ☐ No, Comments
Any evidence notable Internal Corrosion found on piping or equipment?	☐ Yes, ☐ No, Comments
Any Manufacturing defects found on fittings, casings/castings, elastomers?	☐ Yes, ☐ No, Comments
Any Welding/Fabrication Defects noted?	☐ Yes, ☐ No, Comments
Any Equipment failures discovered	☐ Yes, ☐ No, Comments
Any damages discovered as a result of Third Party activities?	☐ Does Not Apply, ☐ Traffic damage, ☐ Vandalism, Other:
Have Incorrect Operations impacted the Facility since the last survey?	☐ Yes, ☐ No, Comments
Any obvious leaks or indications of a leak such as stains around valves or flanges or stained soil or gravel?	☐ Yes, ☐ No, Comments
Any leaks at tubing connections or corrosion of piping or auxiliary piping?	☐ Yes, ☐ No, Comments
Any evidence of excessive vibration of pipe or auxiliary piping that could result in fatigue related failures?	☐ Yes, ☐ No, Comments
Any sign of sump overflows?	☐ Yes, ☐ No, Comments
Any loose connections of threaded or flanged fittings noticed?	☐ Yes, ☐ No, Comments

Any evidence of product sheens found?	☐ Yes, ☐ No, Comments
Any damage found to security fencing, signs of vandalism or unauthorized access?	☐ Yes, ☐ No, Comments
Any evidence of noteworthy corrosion at piping air-soil interfaces and at pipe supports?	☐ Yes, ☐ No, Comments
Has the following protective devices been inspected or calibrated in the previous 12 months?	Pressure Regulators ☐ Yes, ☐ No, ☐ N/A Control Valves ☐ Yes, ☐ No, ☐ N/A Pressure Switches ☐ Yes, ☐ No, ☐ N/A ☐ Temperature Switches ☐ Yes, ☐ No, ☐ N/A Level Gauges, Switches, Alarms ☐ Yes, ☐ No, ☐ N/A
Are the protective devices adequate for the intended function and are reliable?	☐ Yes, ☐ No, Comments
Underground Sump(s) on site?	☐ Yes ☐ No
MOP	Line into Facility: Segment ID: Line out of Facility: Segment ID:
Pump(s)	Pump Number(s): 1: , 2: , 3: , 4: Pump HP: 1: , 2: , 3: , 4: Pump Monitoring: ☐ Continuous Vibration Monitoring, ☐ Manual Vibration Monitoring, ☐ Seal Leak Detection, ☐ Low Suction Shutdown, Low Suction Pressure: psig
Pumps Shut down on high pressure:	☐ Yes, Pressure: psig ☐ No
Station over-pressure protection	Type of over-pressure protection used: Over-pressure protection set points:
Additional Information:	

EMERGENCY RESPONSE CAPABILITIES:

Response time from Fire Department	
Response time from Police/Sheriff	
Fire Fighting Equipment available at site:	
Spill containment equipment available at site:	
Pre-Determined product containment recovery sites identified?	☐ Yes, ☐ No. If so, where?
Emergency response training such as periodic emergency drills?	☐ Yes, ☐ No. How often? .
Participation with joint response groups	☐ Yes, ☐ No
Additional Information:	

PIPING SYSTEM INTEGRITY:

Aboveground Pipe Coating Condition	☐ Excellent ☐ Very Good ☐ Good ☐ Poor
Underground Pipe Coating Condition	☐ Excellent ☐ Very Good ☐ Good ☐ Poor ☐ Unknown
Corrosion Probe(s) Installed	☐ Yes ☐ No
Corrosion Coupon(s) Installed	☐ Yes ☐ No
If Corrosion Probes or Coupons exist, have there been any changes from the last facility evaluation or trends seen from inspection to inspection; explain:	
Cathodic Protection:	Last CP survey: Last CIS completed: CP issues needing addressing:
Underground piping:	Buried Flanges: ☐ Yes ☐ No ☐Unknown Buried Threaded Connections: ☐ Yes ☐ No ☐ Unknown
Electrical System:	Any known deficiencies: Any known Improvements needed:
Communications with Control Center:	Are there any areas needing improvement:
Additional Information:	

PREVENTIVE AND MITIGATIVE MEASURES:

Changes made to this facility in the past 12 months that would serve to Prevent or lessen the likelihood of releases from happening:	
Changes made to the facility in the past 12 months that would Mitigate or lessen the impact of a release on a High Consequence Area should there be a release:	
In the opinion of the Area Supervisor, are the existing Preventive and Mitigative Measures appropriate and effective for the threats applicable to the facility and/or in reducing the consequences of a release?	☐ Yes, ☐ No, Comments
In the opinion of the Area Supervisor, are the current P&M measures in place sufficient to protect the impacted HCAs?	☐ Yes, ☐ No, Comments

GENERAL:

- Area Supervisor's recommendation for improvements to Facility Integrity:
- Additional Comments:

CITGO Doc # **IMP-PR0018**	**Pipeline Integrity Management**	
	Doc. Title: **CONTINUAL EVALUATION PROCEDURE**	**CITGO Pipeline Company** Tulsa, Oklahoma
Reviewed By: C. Fairless Pipeline Integrity Manager	Approved By: K. Lloyd Manager Engineering, Pipeline Compliance & Control	Approved By: K. Powers General Manager, Terminals and Pipelines
Original Release Date: 8/11/08	Revision 0 Rev. Release Date: NA	Page 1 of 6

1 PURPOSE

1.1 The purpose of this document is to describe the standardized procedure for Continual Evaluation of the effectiveness of ongoing management of pipeline integrity for pipelines and facilities that could affect a High Consequence Area.

2 SCOPE

2.1 This procedure applies to all liquid pipelines owned by CITGO Pipeline Company or operated by CITGO Pipeline Company that could affect an HCA.

3 RELATED DOCUMENTS

3.1	IMP-PL0001	Integrity Management Plan for DOT Part 195 and Texas Rule 8.101
3.2	IMP-PR0009	Preventive and Mitigative Measures Procedure
3.3	IMP-PR0010	Program Evaluation and Continuous Improvement Procedure
3.4	IMP-PR0013	Threat Identification and Risk Assessment Procedure
3.5	IMP-PR0015	Reassessment Interval Procedure
3.6	IMP-SC0002	CITGO Continual Assessment Plan
3.7	IMP-SC0008	CITGO Terminal Continual Assessment Plan

4 DEFINITIONS

4.1 High Consequence Area (HCA) – As defined by the Department of Transportation Section 195.450 and includes impacts to "Commercially

Navigable Waterways," "High Population Areas," "Other Population Areas," and "Unusually Sensitive Areas" (USA).

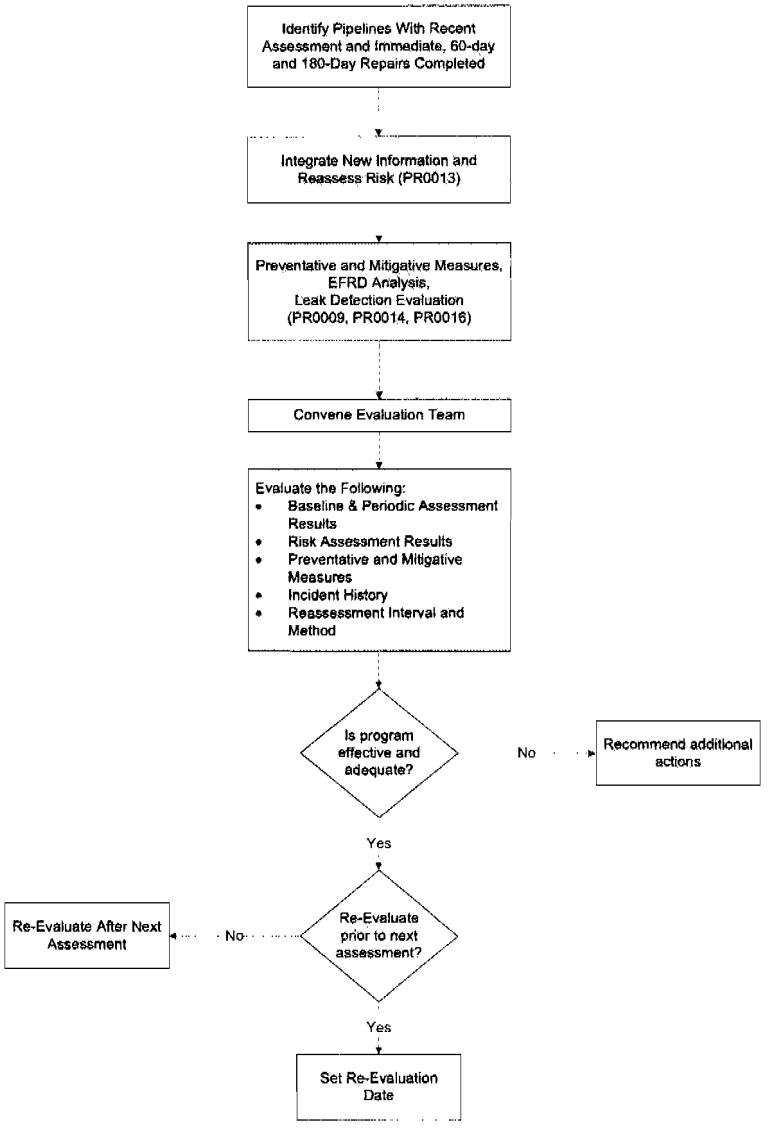
4.2 Pipeline Section – Pre-defined portion of a pipeline that can be internally inspected, from launching device to receiving device (piggable section), or a portion of a pipeline that can be hydro-tested.

5 RESPONSIBILITIES AND TRAINING

5.1 The Pipeline Integrity Manager and/or Integrity Engineer shall be responsible for initiating the Continual Evaluation procedure and shall be trained to understand and apply the directions in this procedure.

5.2 The Continual Evaluation Team members are responsible for preparing for and attending meetings, gathering and providing requested information, and assuring that input data is accurate to the best of their knowledge.

6 PROCESS FLOW DIAGRAM



7 PROCEDURE

7.1 Complete Assessment for a Pipeline Section and Reassess Risk

7.1.1 Identify all pipeline sections that have undergone a recent integrity assessment and have had all the Immediate, 60-Day and 180-Day repairs completed.

7.1.2 Follow the process in Threat Identification and Risk Assessment Procedure, IMP-PR0013, to integrate new information and reassess risk.

7.2 Complete Preventative and Mitigative Measures Procedure (PR0009), EFRD Analysis Procedure (PR0014), and Leak Detection Evaluation Procedure (PR0016)

7.3 Gather Information Needed for Evaluation

7.3.1 For each pipeline section or facility being evaluated, the Integrity Management group will assemble the following information for use during the Evaluation Meeting:

- Baseline and Periodic Assessment Results (Summary ILI Assessment Reports)
- Risk Assessment Results
- Preventative and Mitigative Measures Reports
  - EFRD Analysis Results
  - Leak Detection Evaluation Results
  - IMPACT Action Items
- Incident History
- Remediation History
- Reassessment Interval and Method (Continual Assessment Plans)
- Program Evaluation Results (Annual Report)

7.4 Convene Continual Evaluation Team

7.4.1 The Pipeline Integrity Manager convenes a representative committee of CITGO personnel, herein referenced as the Continual Evaluation Team (CET). Other personnel external to the company may be included as

subject matter experts if needed. The following personnel will normally comprise the CET:

- Pipeline Integrity Manager or designated Committee Chairperson
- Engineer(s) knowledgeable in pipeline operations
- Corrosion Engineer and / or CP Techs
- Pipeline Control Center Manager
- Pipeline Health, Safety, Security, and Environmental representative(s)
- Pipeline Area Supervisor responsible for pipeline sections being evaluated

7.4.2 The objective of the CET is to determine if the Integrity Management program in place for a given line section or facility is effective and adequate to assure integrity. The CET will review and evaluate the information specified above in order to make the determination.

7.4.2.1 Indications that the Integrity Program is effective and adequate include the following:

- No recent releases
- Effective P&M Measures in place for major threats
- Number of anomalies requiring remediation during assessments trending down
- Assessments being completed as scheduled
- Risk Assessment results show trend over time toward decreasing risk.
- Internal and external program audits reveal procedures are adequate

7.4.2.2 If the CET determines the Integrity Program is not effective and adequate, the CET will make and document recommendations for improvement. Recommendations for improvement may include, but are not limited to, the following:

- Changes to O&M Manual Procedures
- Changes to Control Center Procedures
- Changes to Emergency Procedures
- Additional assessments or more frequent reassessments
- New or expanded Preventive and Mitigative Measures

7.4.3 The CET determines the next evaluation interval. The next evaluation interval will normally be after the next reassessment and after implementation of other necessary Integrity Management Procedures as outlined above. If the CET has determined that the program is not adequate and effective, a more frequent evaluation interval may be necessary. In either case, the CET will determine and document the next evaluation interval.

8 RECORDS

8.1 Continual Evaluation Meeting Notes.

1 PURPOSE

1.1 The purpose of this document is to describe the standardized procedure in the Integrity Management Program for determining the reassessment interval of pipelines that could affect a High Consequence Area.

2 SCOPE

2.1 This procedure applies to all liquid pipelines owned by CITGO Pipeline Company or operated by CITGO Pipeline Company that could affect an HCA.

3 RELATED DOCUMENTS

3.1	IMP-PL0001	Integrity Management Plan for DOT Part 195 and Texas Rule 8.101
3.2	IMP-PR0013	Threat Identification and Risk Assessment Procedure
3.3	IMP-SC0002	CITGO Continual Assessment Plan
3.4	IMP-SC0008	CITGO Terminal Continual Assessment Plan

4 DEFINITIONS

4.1 Half-life – Calculated by determining the time for defects to reach critical severity level and dividing by two. This becomes the half-life of the anomaly in question and the longest interval between reassessments.

4.2 High Consequence Area (HCA) – As defined by the Department of Transportation Section 195.450 and includes impacts to "Commercially Navigable Waterways," "High Population Areas," "Other Population Areas," and "Unusually Sensitive Areas" (USA).

4.3 Pipeline Risk Segment – A portion of a Pipeline Section that intersects an HCA or could affect a HCA by any of the following methods: (1) Direct intersection with an HCA or NHD stream, (2) ¼ mile buffer around an HCA for hazardous liquid lines, (3) 5 mile buffer around an HCA for highly volatile liquid lines, or (4) Land or water transport of a release to an HCA or NHD stream. A Pipeline Section may have multiple risk segments

4.4 Pipeline Section – Pre-defined portion of a pipeline that can be internally inspected, from launching device to receiving device (piggable section), or a portion of a pipeline that can be hydro-tested.

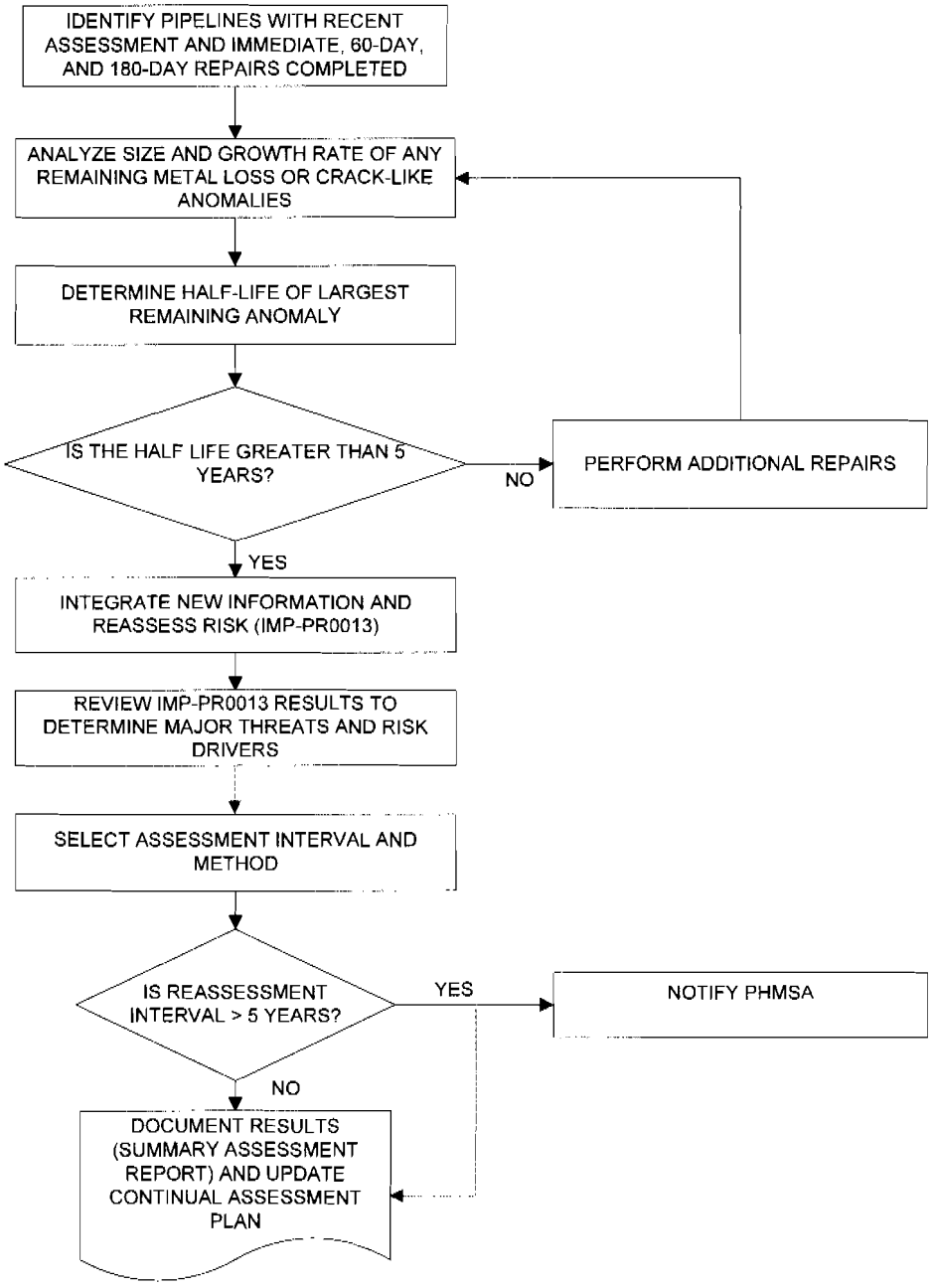
4.5 PHMSA – Pipeline and Hazardous Materials Safety Administration

5 RESPONSIBILITIES AND TRAINING

5.1 The Pipeline Integrity Manager and/or Integrity Engineer shall be responsible for reassessment interval determination and shall be trained to understand and apply the directions in this procedure.

5.2 The Integrity Engineer is responsible for making any necessary half-life calculations, documenting the results and recommending a reassessment interval and method.

6 PROCESS FLOW DIAGRAM



7 PROCEDURE

7.1 Complete Repairs From Previous Integrity Assessment

7.1.1 This process will be implemented after all the IM required Immediate, 60-Day and 180-Day repairs are completed from an integrity assessment.

7.2 Analyze Size and Growth Rate of any Remaining Metal Loss or Crack-like Anomalies.

7.2.1 The Integrity Engineer and / or the Corrosion Engineer will review the results of the most recent integrity assessment to determine which un-repaired metal loss or crack-like anomalies represent the biggest threat to the integrity of the pipe (deepest reported depth or lowest calculated burst pressure).

7.2.2 The Integrity Engineer and / or the Corrosion Engineer will determine the estimated growth rate (corrosion or fatigue, as applicable) of the anomalies identified above using accepted, industry standard practices.

7.3 Determine Half-Life of Largest Remaining Anomalies

7.3.1 To determine a safe re-assessment interval, the time for the remaining worst case (minimum time to failure) metal loss or crack-like anomalies to grow until the calculated failure (burst) pressure is equal to the Maximum Operating Pressure of the pipeline section, or until the estimated depth of a metal loss anomaly is 80%, whichever is less, will be divided by a factor of 2.

7.3.2 The interval calculated above becomes the half life of the anomalies and the maximum re-assessment interval.

7.4 Is the Half-Life Greater than Five Years?

7.4.1 If yes, the half-life of any remaining anomalies is greater than five years, continue to the next step to Select Assessment Interval and Method.

7.4.2 If no, the half-life of any remaining anomalies is less than five years, the Integrity Engineer will recommend one of the following:

- Recommend additional repairs until the calculated re-assessment interval of any remaining anomalies is equal to or greater than 5 years, or;
- Recommend a re-assessment interval shorter than 5 years. (Only in unusual circumstances would this be the preferred option)

7.5 Select Assessment Interval and Method

7.5.1 CITGO bases the assessment interval on the risk the line pipe poses to HCAs. Procedure PR-0013 Threat Identification and Risk Assessment addresses the factors required by 49 CFR 195.452(j)(3).

7.5.2 The Integrity Engineer and/or the Integrity Manager will review the results of procedure PR-0013 Threat Identification and Risk Assessment to determine the major threats and risk drivers to assist in determining the assessment interval and method. The assessment method and interval will be based on the threats that are applicable to the risk segments within a pipeline section.

7.5.3 Unless a more frequent assessment interval has been recommended as part of the Preventive and Mitigative Measures analysis (PR-0009) or as part of the Continual Evaluation process (PR-0018), the reassessment interval will be determined as indicated below.

7.5.4 External or Internal Corrosion - Maximum interval will be 5 years (not to exceed 68 months) from last assessment, unless a longer interval has been approved by PHMSA for the section. Assessment method will be one of the following:

- In-Line Inspection
- Pressure Test
- Other Technology if approved by PHMSA for the section.

7.5.5 Stress Corrosion Cracking

7.5.5.1 Inspection Activities or Assessment Interval: If conditions for SCC are present (i.e., meets criteria), a written plan for the

affected segment shall be prepared by the Corrosion Engineer.

7.5.5.2 Inspection or Assessment Method: Will be addressed in the written plan for the affected segment.

7.5.6 Manufacturing Defects (Seam)

7.5.6.1 If a pipeline segment is at risk for seam related pressure cycle fatigue, the maximum interval will be 5 years (not to exceed 68 months) from last assessment, unless a longer interval has been approved by PHMSA for the section. Assessment method will be one of the following:

- In-Line Inspection (Crack Tool)
- Pressure Test
- Other Technology if approved by PHMSA for the section.

7.5.7 Manufacturing Defects (Pipe body)

7.5.7.1 Periodic assessment is not required.

7.5.7.2 When raising the MOP or if other conditions warrant, a hydrostatic test will be the assessment method.

7.5.8 Construction Errors (Pipe Girth Weld, Wrinkle Bend or Buckle, Stripped Threads/Broken Pipe/Coupling)

7.5.8.1 Periodic assessment is not required.

7.5.8.2 Inspections and Preventative Measures are required to address this threat. For example, excavation protocols to ensure that pipe is not moved or that girth weld reinforcement is applied whenever acetylene welds are exposed.

7.5.9 Equipment (Gaskets and O-Ring, Control/Relief, Seal/Packing)

7.5.9.1 Periodic assessment is not required.

7.5.9.2 Inspections for this threat are conducted per the requirements of the O&M procedures.

7.5.10 Third Party Damage (TPD)

7.5.10.1 TPD is a time independent threat and strong preventive measures are required at all times, especially in areas of concern. Unless a risk assessment indicates that a shorter assessment interval is warranted, the maximum interval will be 5 years (not to exceed 68 months) from last assessment, unless a longer interval has been approved by PHMSA for the section.

7.5.10.2 Assessment method will be one of the following:

- In-Line Inspection
- Pressure Test
- Other Technology if approved by PHMSA for the section.

7.5.11 Incorrect Operations

7.5.11.1 If the data shows that operation and maintenance are performed in accordance with procedures, the procedures are correct, and operating personnel are adequately qualified to fulfill the requirements of the procedure, no additional assessment is required.

7.5.11.2 Procedure audits or reviews are conducted periodically by company personnel and/or third-party experts.

7.5.12 Outside Forces (Earth Movement, Heavy Rains/Floods, Cold Weather, Lightning)

7.5.12.1 Inspections for this threat are conducted per the requirements of the O&M procedures.

7.5.13 Changes to the segment may drive re-assessment if the changes affect pipeline integrity. If no changes are experienced, re-assessment is not required.

7.6 Reassessment Intervals Greater Than 5 Years

7.6.1 At this time, CITGO plans to perform all integrity assessments at a maximum five (5) years (not to exceed 68 months) interval.

7.6.2 If CITGO plans to exceed the nominal 5 year re-assessment interval, the Pipeline Integrity Manager will submit notification to PHMSA for a longer assessment interval at least 270 days before the re-assessment is due. Notification will include sufficient documentation to technically justify the analyses and decisions leading to a request for extension.

7.7 Issues Affecting Schedule

7.7.1 CITGO actively addresses issues that could adversely impact meeting assessment schedules. Assessment dates shall be selected based on the associated risk for the pipeline section (with the highest risk sections receiving the priority in scheduling of dates). Some of the issues that might impact schedules are:

- Weather factors; particularly cold weather in northern climates and heavy rains/flooding conditions in southern climates
- Change in operations or shipping schedules
- Preparation of lines to accept in-line tools
- Vendor/contractor availability

7.8 Document Results

7.8.1 Update the applicable Continual Assessment Plan with the new assessment intervals.

7.8.2 Results of the Engineers review of PR0013 Threat Identification and Risk Assessment Procedure to determine major threats and risk drivers, as well as the recommendation for assessment interval and method will be documented in the Engineers Summary ILI Assessment Report (See PR0006, Section 6.10)

7.8.3 Maintain results of half life calculations in IMP files until next assessment is complete.

8 RECORDS

8.1 IMP-SC0002 CITGO Continual Assessment Plan

8.2 IMP-SC0004 West Shore Continual Assessment Plan

8.3 IMP-SC0008 CITGO Terminal Continual Assessment Plan

8.4 Half life calculation records

8.5 Summary ILI Assessment Report