VENOCO, INC.

Hazardous Liquid Pipeline

Operations & Maintenance Procedures

2016

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FORWARD

Hazardous Liquid Pipeline O&M Procedure Forward

Primary Ref: 49 CFR 195.266, 195.404	**Updated: Jan 2016**

The United States Department of Transportation (DOT), Office of Pipeline Safety (OPS) requires that the design, installation, operation, and maintenance of regulated pipeline facilities conform to the requirements of Title 49 of the Code of Federal Regulations (49 CFR).

The Company policies mandate compliance with all applicable legal requirements wherever we conduct business and providence of an environment where employees and contractors work safely.

This manual contains procedures, information, references, and forms that provide guidance for the Company employees and contractors to comply with the aforementioned Federal regulations, California regulations, and company policies.

The information contained in this manual should be applied to all regulated pipelines and facilities. Local regulations, as well as specific information about individual pipeline systems/segments are not in the scope of this manual.

This manual is to be used in conjunction with a Pipeline Specific Operations Manual (PSOM) and a pipeline specific Emergency Response Plan (ERP). The PSOM and ERP must be developed by the local facility personnel.

This manual shall be prepared before initial operations and of a pipeline system commence. Appropriate parts shall be kept at locations where operations and maintenance activities are conducted. This manual shall be review once per calendar year, not to exceed 15 months. Appropriate changes will be made as necessary to insure that the manual is effective.

Periodically (once per year) the company shall review the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

The company will make all construction records, maps, and operating history available as necessary for safe operation and maintenance. [195.402(c)(1)]

This manual shall be made available to any authorized representative of the DOT/OPS upon request.

Liquid O&M Record of Revisions: 2015
Due to new PHMSA audit protocols and audits on a couple California pipeline operators by CSFM and PHMSA, all of the following procedures were updated. All updates are shown in red in the specific procedure. Updates in the plan are identified in **RED**

Liquid O&M procedures updated:

1) Table of Contents
2) Forward
3) How to Us Numbered Blanks and Blank Assignment Table- Assignment Table
4) Cross Reference Tables
5) List of Forms
6) #1.01, Reporting Accidents
7) #1.03, Investigation of Failures
8) #1.04, Jurisdictional and Regulatory Review
9) #1.07, HCA Survey
10) #1.08, PHMSA OPID
11) #2.01, Recordkeeping
12) #2.02, Marking of Materials
13) #3.01, Damage Prevention
14) #3.04, Preparation of an Emergency Plan
15) #4.01, Scraper and Sphere Facilities
16) #4.02, Breakout Tanks
17) #4.03, Pumping Equipment
18) #5.03, Patrolling
19) #6.01, Atmospheric Corrosion
20) #6.02, Internal Corrosion
21) #6.03, External Protective Coating
22) #6.04, Internal and External Examination of Buried Pipe When Exposed
23) #6.05, CP and External Corrosion Control
24) #6.06, Electrical Isolation
25) #6.07, Impressed Current Inspection
26) #6.08, CP Maps and Records
27) #6.09, Unprotected Pipe
28) #6.10, District Office Review
29) #7.01. Inspect & Maintain Em Valves
30) #9.01, Repairs
31) #9.06, Welding
32) #13.01, Abandonment
33) #14.01, Valve Security

34) #15.01, Pressure Testing 35) #15.02, Visual Inspection and NDT

Liquid O&M Record of Revisions: 2015 (cont.)
Due to new PHMSA audit protocols and audits on a couple California pipeline operators by CSFM and PHMSA, all of the following procedures were updated. All updates are shown in red in the specific procedure.
Liquid O&M procedures updated: 36) Form #1.03, Accident and Near Miss 37) Form #1.04C, Chain of Custody 38) Form #6.01A, Atm Corrosion 39) Form #6.02B-2, Evaluation of Liquid Analysis 40) Form #7.02C, Capacity Review 41) Form #12.02, Step by Step Conversion of Service 42) Form #14.05A Monthly Firefighting Equip Inspection 43) From 16.01-B Annual Review of Emergency Training Objectives 44) PHMSA Form #3, Hazardous Liquid Inspection Protocols with Answers

Signature & Date of Person Who Conducted Annual Review of O&M Manual:

Signature

Date 4/12/16

Hazardous Liquid Pipeline O&M Assignment Table

FN: Liquid O&M assignment table template, v2016
Updated: Feb 2016

Blank #	O&M Tab & Section #	Procedure #	Section # Title	O&M Section # in Procedure	Procedure Name	Person or Title of Person Responsible:
1	1	1.01	Pipeline Failure, Reporting, and Investigation	3	Reporting of Control of Incidents	EHS
2	1	1.01	Pipeline Failure, Reporting, and Investigation	5.5	Reporting of Control of Incidents	EHS
3	1	1.01	Pipeline Failure, Reporting, and Investigation	7.2	Reporting of Control of Incidents	OS
4	1	1.01	Pipeline Failure, Reporting, and Investigation	8.1.2	Reporting of Control of Incidents	EHS
5	1	1.01	Pipeline Failure, Reporting, and Investigation	8.2	Reporting of Control of Incidents	EHS
6	1	1.01	Pipeline Failure, Reporting, and Investigation	8.3	Reporting of Control of Incidents	EHS
7	1	1.01	Pipeline Failure, Reporting, and Investigation	8.4	Reporting of Control of Incidents	EHS
8	1	1.01	Pipeline Failure, Reporting, and Investigation	8.4.1	Reporting of Control of Incidents	EHS
9	1	1.01	Pipeline Failure, Reporting, and Investigation	8.5	Reporting of Control of Incidents	EHS
10	1	1.01	Pipeline Failure, Reporting, and Investigation	8.5.1	Reporting of Control of Incidents	EHS
11	1	1.01	Pipeline Failure, Reporting, and Investigation	8.7	Reporting of Control of Incidents	EHS
12	1	1.01	Pipeline Failure, Reporting, and Investigation	8.7.7	Reporting of Control of Incidents	EHS
13	1	1.01	Pipeline Failure, Reporting, and Investigation	10.1	Reporting of Control of Incidents	EHS
22	1	1.02	Pipeline Failure, Reporting, and Investigation	3	Reporting of Safety Related Conditions	EHS
23	1	1.02	Pipeline Failure, Reporting, and Investigation	3	Reporting of Safety Related Conditions	OS
24	1	1.02	Pipeline Failure, Reporting, and Investigation	4.2	Reporting of Safety Related Conditions	OS
25	1	1.02	Pipeline Failure, Reporting, and Investigation	4.2	Reporting of Safety Related Conditions	EHS
26	1	1.02	Pipeline Failure, Reporting, and Investigation	4.3	Reporting of Safety Related Conditions	EHS
27	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.4	Reporting of Safety Related Conditions	EHS
28	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.4	Reporting of Safety Related Conditions	EHS
29	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.4	Reporting of Safety Related Conditions	EHS
30	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.4	Reporting of Safety Related Conditions	EHS
31	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	EHS
32	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	EHS
33	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	EHS
34	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	SPE
35	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	EHS
36	1	1.02	Pipeline Failure, Reporting, and Investigation	5.2.6	Reporting of Safety Related Conditions	EHS
42	1	1.03	Pipeline Failure, Reporting, and Investigation	3	Investigation of Failures and Accidents	EHS
43	1	1.03	Pipeline Failure, Reporting, and Investigation	4.1	Investigation of Failures and Accidents	EHS
44	1	1.03	Pipeline Failure, Reporting, and Investigation	4.2	Investigation of Failures and Accidents	EHS
45	1	1.03	Pipeline Failure, Reporting, and Investigation	4.2	Investigation of Failures and Accidents	N/A
46	1	1.03	Pipeline Failure, Reporting, and Investigation	4.4	Investigation of Failures and Accidents	COMPANY
47	1	1.03	Pipeline Failure, Reporting, and Investigation	5.1	Investigation of Failures and Accidents	OS
48	1	1.03	Pipeline Failure, Reporting, and Investigation	5.2	Investigation of Failures and Accidents	SPE

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49	1	1.03	Pipeline Failure, Reporting, and Investigation	5.2.2	Investigation of Failures and Accidents	EHS
50	1	1.03	Pipeline Failure, Reporting, and Investigation	5.2.5	Investigation of Failures and Accidents	SPE
51	1	1.03	Pipeline Failure, Reporting, and Investigation	7.2	Investigation of Failures and Accidents	EHS
57	1	1.04	Pipeline Failure, Reporting, and Investigation	3	Jurisdictional/Regualtory	SPE
58	1	1.04	Pipeline Failure, Reporting, and Investigation	7.1	Jurisdictional/Regualtory	SPE
59	1	1.04	Pipeline Failure, Reporting, and Investigation	7.1	Jurisdictional/Regualtory	SPE
60	1	1.04	Pipeline Failure, Reporting, and Investigation	7.2	Jurisdictional/Regualtory	SPE
61	1	1.04	Pipeline Failure, Reporting, and Investigation	7.3	Jurisdictional/Regualtory	SPE
62	1	1.04	Pipeline Failure, Reporting, and Investigation	7.4	Jurisdictional/Regualtory	SPE
63A	1	1.04	Pipeline Failure, Reporting, and Investigation	7.5	Jurisdictional/Regualtory	SPE
63B	1	1.04	Pipeline Failure, Reporting, and Investigation	7.6	Jurisdictional/Regualtory	SPE
64	1	1.05	Pipeline Failure, Reporting, and Investigation	3	Pipeline Annual Reports	SPE
65	1	1.05	Pipeline Failure, Reporting, and Investigation	3	Pipeline Annual Reports	SPE
66	1	1.05	Pipeline Failure, Reporting, and Investigation	6.0	Pipeline Annual Reports	SPE
67	1	1.05	Pipeline Failure, Reporting, and Investigation	7.1		SPE
68	2	2.01	Inspection and Recordkeeping	3	Recordkeeping	SPE
69	2	2.01	Inspection and Recordkeeping	5.1	Recordkeeping	SPE
70	2	2.01	Inspection and Recordkeeping	5.2	Recordkeeping	SPE
77	2	2.02	Inspection and Recordkeeping	3	Marking and Documentation of Materials	SPE
83	3	3.01	Plans and Programs	3	Damage Prevention Program	EHS
84	3	3.01	Plans and Programs	5.7.1	Damage Prevention Program	OS
90	3	3.02	Plans and Programs	3	Telephone Answering Services	EHS
97	3	3.03	Plans and Programs	3	3.03 Not in Use - Public Awareness Program moved to PSOM section #18.	
97B	3	3.03	Plans and Programs	4		
98	3	3.03	Plans and Programs	4.2		
106	3	3.04	Plans and Programs	3	Preparation of an Emergency Plan	EHS
111	3	3.05	Plans and Programs	3	Crossing of Company Pipelines	SPE/FE
112	3	3.05	Plans and Programs	7.3	Crossing of Company Pipelines	DD
118	3	3.06	Plans and Programs	3	Preparation of Pipeline Specific O&M (PSOM)	SPE
119	3	3.06	Plans and Programs	3	Preparation of Pipeline Specific O&M (PSOM)	OS
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130	4	4.01	Micellanous Mechanical Equipment	3	Scraper and Sphere Facilities	OS
131	4	4.01	Micellanous Mechanical Equipment	3	Scraper and Sphere Facilities	OS
133	4	4.02	Micellanous Mechanical Equipment	3	Breakout Tanks	OS

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Blank #	O&M Tab & Section #	Procedure #	Section # Title	O&M Section # in Procedure	Procedure Name	Person or Title of Person Responsible:
134	4	4.02	Micellanous Mechanical Equipment	3	Breakout Tanks	OS
140	4	4.03	Micellanous Mechanical Equipment	3	Pumping Equipment	OS
141	4	4.03	Micellanous Mechanical Equipment	3	Pumping Equipment	OS
148	5	5.01	Surveillance and Patrolling	3	Continuing Surveillance	OS
149	5	5.01	Surveillance and Patrolling	3	Continuing Surveillance	OS
151	5	5.02	Surveillance and Patrolling	NA	Not in Use	NA
154	5	5.03	Surveillance and Patrolling	3	Patrolling	OS
160	5	5.04	Surveillance and Patrolling	3	Pipeline Markers and Signs	OS
167	6	6.01	Pipeline Corrosion Control	3	Atmospheric Corrosion	OS
168	6	6.01	Pipeline Corrosion Control	3	Atmospheric Corrosion	OS
173	6	6.02	Pipeline Corrosion Control	3	Internal Corrosion	OS
174	6	6.02	Pipeline Corrosion Control	3	Internal Corrosion	SPE/FE
180	6	6.03	Pipeline Corrosion Control	3	External Protective Coating	SPE/FE
186	6	6.04	Pipeline Corrosion Control	3	Internal & External Examination of Buried Pipe	SPE/FE
193	6	6.05	Pipeline Corrosion Control	4.1	Cathodic Protection External Corrosion Control	SPE/FE
194	6	6.05	Pipeline Corrosion Control	5.4	Cathodic Protection External Corrosion Control	SPE/FE/OS
200	6	6.06	Pipeline Corrosion Control	3	Electrical Isolation	SPE/FE
206	6	6.07	Pipeline Corrosion Control	3	Impressed Current Power Source Inspection	OS
207	6	6.07	Pipeline Corrosion Control	5.3.2	Impressed Current Power Source Inspection	OS
208	6	6.07	Pipeline Corrosion Control	5.3.3	Impressed Current Power Source Inspection	OS
214	6	6.08	Pipeline Corrosion Control	3	Cathodic Protection Maps and Records	SPE/FE/OS
221	6	6.09	Pipeline Corrosion Control	3	Evaluation of Bare or Buried Unprotected Pipe	SPE/FE
227	6	6.10	Pipeline Corrosion Control	2	District Office Review	FE/SPE
228	6	6.10	Pipeline Corrosion Control	3	District Office Review	OS
229	6	6.10	Pipeline Corrosion Control	4	District Office Review	FE/SPE
230	6	6.10	Pipeline Corrosion Control	5	District Office Review	SPE/FE
237	7	7.01	Valves	3	Inspect and Maintain Emergency Valves	OS
238	7	7.01	Valves	4.2	Inspect and Maintain Emergency Valves	SPE/FE
239	7	7.01	Valves	4.3	Inspect and Maintain Emergency Valves	OS
245	7	7.02	Valves	3	Pressure Regulators and Relief Devices	OS
251	8	8.01	Operating Pressure Limitation	3	Maximum Operating Pressure (MOP)	SPE/FE
252	8	8.01	Operating Pressure Limitation	3	Maximum Operating Pressure (MOP)	OS
253	8	8.01	Operating Pressure Limitation	5.1	Maximum Operating Pressure (MOP)	SPE/FE
254	8	8.01	Operating Pressure Limitation	7.2	Maximum Operating Pressure (MOP)	DD
257	8	8.02	Operating Pressure Limitation	3	Operating Pressure Limits - Maintenance & Repair	OS

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Blank #	O&M Tab & Section #	Procedure #	Section # Title	O&M Section # in Procedure	Procedure Name	Person or Title of Person Responsible:
260	9	9.01	Repair, Construction, and Welding	3	Pipeline Repair Procedures	SPE/FE
261	9	9.01	Repair, Construction, and Welding	7.2	Pipeline Repair Procedures	SPE/FE
263	9	9.02	Repair, Construction, and Welding	NA	Not in Use	NA
264	9	9.03	Repair, Construction, and Welding	NA	Not in Use	NA
265	9	9.04	Repair, Construction, and Welding	NA	Not in Use	NA
267	9	9.05	Repair, Construction, and Welding	3	Tapping Pipelines	SPE/FE
268	9	9.05	Repair, Construction, and Welding	7.1	Tapping Pipelines	DD
274	9	9.06	Repair, Construction, and Welding	3	Pipeline Welding	SPE/FE/CS
275	9	9.06	Repair, Construction, and Welding	3	Pipeline Welding	SPE/FE/CS
276	9	9.06	Repair, Construction, and Welding	3	Pipeline Welding	SPE/FE/CS
282	12	12.01	Change of Pipeline Operating Characteristics	3	Pipeline Uprating	SPE/FE
283	12	12.01	Change of Pipeline Operating Characteristics	3	Pipeline Uprating	OS
284	12	12.01	Change of Pipeline Operating Characteristics	4	Pipeline Uprating	SPE/FE
290	12	12.02	Change of Pipeline Operating Characteristics	3	Conversion of Service	SPE/FE
296	12	12.03	Change of Pipeline Operating Characteristics	3	Pipe Movement	SPE/FE
297	12	12.03	Change of Pipeline Operating Characteristics	5	Pipe Movement	SPE/FE
303	13	13.01	Pipeline Abandonment	3	Abandonment or Inactivation of Facilities	SPE
304	13	13.01	Pipeline Abandonment	6.4	Abandonment or Inactivation of Facilities	EHS
305	13	13.01	Pipeline Abandonment	9.1	Abandonment or Inactivation of Facilities	SPE
311	14	14.01	Safety and Security	3	Valve Security	OS
312	14	14.01	Safety and Security	4.1	Valve Security	OS
313	14	14.01	Safety and Security	4.3	Valve Security	OS
314	14	14.01	Safety and Security	5.1	Valve Security	OS
320	14	14.02	Safety and Security	3	Pipe Isolations Lock and Tag	OS/CS
326	14	14.03	Safety and Security	3	Prevention of Accidental Ignition	OS
332	14	14.04	Safety and Security	3	Excavations	OS/CS
338	14	14.05	Safety and Security	3	Fire Fighting Equipment	OS
339	14	14.05	Safety and Security	4.2	Fire Fighting Equipment	OS
345	15	15.01	Testing Requirements	3	Pressure Testing	SPE/FE
351	15	15.02	Testing Requirements	3	Visual Inspection & Nondestructive Testing	SPE/FE
357	16	16.01	Training Requirements	3	Training	EHS
	17	17.09	Pipeline Specific O&M		Agency Specific Requirements	OS
	17	17.1	Pipeline Specific O&M		Pinpeline Emergency Plan	OS
	18	18	Pipeline Specific O&M		Public Awareness Program	OS

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Hazardous Liquid Pipeline O&M Cross Reference Table

FN: Liquid O&M x-ref, v2016
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Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
1	195	A	General	Scope			
2	195.1	A	General	Applicability	1.04		4.02
3	195.2	A	General	Definitions	1.04		18.01, 13.01
4	195.3	A	General	Matter Incorporated by Reference	4.02		
5	195.4	A	General	Compatibility Necessary for Transportation of Hazardous Liquids or Carbon Dioxide			
6	195.5	A	General	Conversion to Service Subject to This Part	12.02		
7	195.6	A	General	Unusually sensitive Areas (USAs)			
8	195.8	A	General	Transportation of Hazardous Liquid or Carbon Dioxide in Pipelines Constructed with Other Than Steel Pipe			
9	195.9	A	General	Outer Continental Shelf Pipelines	1.04		
10	195.1	A	General	Responsibility of Operator For Compliance with This Part			
11	195.5	A	Reporting Accidents and Safety Related Subpart Conditions	Conversion to Service Subject to This Part	1.01		
12	195.52	B	Reporting Accidents and Safety Related Subpart Conditions	Telephonic Notice of Certain Accidents	1.01	5	
13	195.54(a)	B	Reporting Accidents and Safety Related Subpart Conditions	Accident Reports - Filing	1.01	8.7.6	
14	195.54(b)	B	Reporting Accidents and Safety Related Subpart Conditions	Accident Reports – Supplemental Report	1.01	8.7.8	
15	195.55	B	Reporting Accidents and Safety Related Subpart Conditions	Reporting Safety Related Conditions - Criteria	1.02	5.1	
16	195.56(a)	B	Reporting Accidents and Safety Related Subpart Conditions	Filing SRC Reporting Timelines	1.02	4.3	
17	196.56(b)	B	Reporting Accidents and Safety Related Subpart Conditions	Filing SRC Reporting Corrective Actions	1.02	5.2.7	
18	195.57	B	Reporting Accidents and Safety Related Subpart Conditions	Filing Offshore Pipeline Condition Reports	2.02		
19	195.58	B	Reporting Accidents and Safety Related Subpart Conditions	Address For Written Reports	1.01		1.02
20	195.59	B	Reporting Accidents and Safety Related Subpart Conditions	Abandoned Underwater Facilities Report	13.01		
21	195.6	B	Reporting Accidents and Safety Related Subpart Conditions	Operator Assistance In Investigation	1.01		1.03

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Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
22	195.62	B	Reporting Accidents and Safety Related Subpart Conditions	Supplies of Accident Report DOT Form 7000-1			
23	195.1	C	Design Requirements	Scope			
24	195.101	C	Design Requirements	Qualifying Metallic Components Other Than Pipe			
25	195.102	C	Design Requirements	Design Temperature			
26	195.104	C	Design Requirements	Variations In pressure			
27	195.106	C	Design Requirements	Internal Design Pressure	8.01		8.02
28	195.108	C	Design Requirements	External Pressure			
29	195.11	C	Design Requirements	External Loads	8.01		
30	195.111	C	Design Requirements	Fracture Propagation			
31	195.112	C	Design Requirements	New Pipe	2.02		
32	195.114	C	Design Requirements	Used Pipe			
33	195.116	C	Design Requirements	Valves	2.02		
34	195.118	C	Design Requirements	Fittings	2.02		
35	195.12	C	Design Requirements	Passage of Internal Inspection Devices	9.01		
36	195.122	C	Design Requirements	Fabricated Assemblies	9.05		
37	195.124	C	Design Requirements	Closures			
38	195.126	C	Design Requirements	Flange connection			
39	195.128	C	Design Requirements	Station Piping			
40	195.13	C	Design Requirements	Fabricated Assemblies			
41	195.132	C	Design Requirements	Design and Construction of Aboveground Breakout Tanks			
42	195.134	C	Design Requirements	CPM Leak Detection			
43	195.2	D	Construction	Scope			
44	195.202	D	Construction	Compliance With Specifications or Standards			
45	195.204	D	Construction	Inspection – General			
46	195.205	D	Construction	Repair, Alteration and Reconstruction of Aboveground Breakout Tanks That Have Been In Service	4.02		
47	195.206	D	Construction	Material Inspection			
48	195.208	D	Construction	Welding of Supports and Braces	8.01		9.06
49	195.21	D	Construction	Pipeline Location			
50	195.212	D	Construction	Bending of Pipe	15.02		
51	195.214(a)	D	Construction	Welding: Procedures	9.06	5	15.02
52	195.214(b)	D	Construction	Welding: Records	9.06	6.12	15.02
53	195.216	D	Construction	Welding: Miter Joints	9.06		
54	195.222(a)	D	Construction	Welders: Qualification of Welders - Procedures to Follow	9.06	5.2	
55	196.222(b)	D	Construction	Welders: Qualification of Welders - Updating Qualifications	10.06	5.2.1	
56	195.224	D	Construction	Welding: Weather	9.06		
57	195.226(a)	D	Construction	Welding: Arc burns repairs	9.04		
58	195.226(a)	D	Construction	Welding: Arc burns not repairable, then removed			
59	195.226(a)	D	Construction	Welding: Arc burns, ground wire			
60	195.228	D	Construction	Welds and Welding Inspection: Standards of Acceptability	9.06		15.02
61	195.230	D	Construction	Welds: Repair or Removal of Defects	9.01		9.06
62	195.234	D	Construction	Welds: Nondestructive Testing	9.01		15.02
63	195.236-195.244	D	Construction	Reserved			

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Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
64	195.246	D	Construction	Installation of Pipe in a Ditch			
65	195.248	D	Construction	Cover Over Buried Pipeline			
66	195.250	D	Construction	Clearance Between Pipe and Underground Structures	3.05		
67	195.252	D	Construction	Backfilling			
68	195.254	D	Construction	Above Ground Components			
69	195.256	D	Construction	Crossing of Railroads and Highways			
70	195.258	D	Construction	Valves: General	7.01		
71	195.26	D	Construction	Valves: Location	7.01		
72	195.262	D	Construction	Pumping Equipment	4.03		
73	195.264	D	Construction	Impoundment, Protection Against Entry, Normal/Emergency Venting or Pressure/Vacuum Relief for Aboveground Breakout Tanks	4.02		
74	195.266	D	Construction	Construction Records	2.01		6.08
75	195.300	E	Pressure Testing	Scope	15.01		
76	195.302(a)	E	Pressure Testing	General Requirements- Relocated, replaced, changed pipe	15.01		
77	195.302(b)	E	Pressure Testing	General Requirements -exceptions to pressure test	16.01		
78	195.302(c)	E	Pressure Testing	General Requirements -exceptions to pressure test	17.01		
79	195.303	E	Pressure Testing	Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines	15.01		
80	195.304	E	Pressure Testing	Test Pressure length of time	15.01		
81	195.305(a)	E	Pressure Testing	Testing of Components	15.01		
82	195.305(b)	E	Pressure Testing	Testing of Components - exceptions			
83	195.306	E	Pressure Testing	Test Medium	15.01		
84	195.307	E	Pressure Testing	Pressure Testing Aboveground Break Out Tanks	4.02		15.01
85	195.308	E	Pressure Testing	Testing of Tie-Ins	15.01		
86	195.310(a)	E	Pressure Testing	Record retention	15.01		
87	195.310(b)	E	Pressure Testing	Records - list of required records	15.01		
88	195.400	F	Operations & Maintenance	Scope	Forward		
89	195.401	F	Operations & Maintenance	General Requirements	5.01		6.02, 6.04
90	195.402	F	Operations & Maintenance	Procedural Manual For Operations, Maintenance, and Emergencies	Forward		1.02, 1.03, 3.04, 3.06, 13.01, 14.03, 14.04
91	195.402(c)(1)	F	Operations & Maintenance	Procedure: Construction maps, records, and operating history			
92	195.402(c)(2)	F	Operations & Maintenance	Procedure: Gathering data for accidents	1.01		
93	195.402(c)(3)	F	Operations & Maintenance	Procedure: Operating and maintaining procedures as follows;	O&M	All	PSOM
94	195.402(c)(4)	F	Operations & Maintenance	Procedure: Determine facilities that require immediate response	PSOM		
95	195.402(c)(5)	F	Operations & Maintenance	Procedure: Analzing pipeline accidents to determin cause	1.03		
96	195.402(c)(6)	F	Operations & Maintenance	Procedure: Minimizing the potential for hazards identified under paragraph (c)(4)	PSOM		
97	195.402(c)(7)	F	Operations & Maintenance	Procedure: Startup and shutdown of the pipeline within MAOP	PSOM		8.01
98	195.402(c)(8)	F	Operations & Maintenance	Procedure: If not equipped to be fail safe	PSOM		
99	195.402(c)(9)	F	Operations & Maintenance	Procedure: If not equipped to be fail safe, monitoring	PSOM		
100	195.402(c)(10)	F	Operations & Maintenance	Procedure: If not equipped to be fail safe, delivery	PSOM		
101	195.402(c)(11)	F	Operations & Maintenance	Procedure: Accidental ignition	14.03		
102	195.402(c)(12)	F	Operations & Maintenance	Procedure: Liaison with fire, police, and other appropriate public officials	Em Plan		3.03
103	195.402(c)(13)	F	Operations & Maintenance	Procedure: Periodically reviewing the work done by operator personnel	PSOM		
104	195.402(c)(14)	F	Operations & Maintenance	Procedure: Precautions in excavated trenches	14.04		
105	195.402(d)(1)	F	Operations & Maintenance	Abnormal Operations - response, investigate, correct	PSOM		
106	195.402(d)(2)	F	Operations & Maintenance	Abnormal Operations - checking variations	PSOM		

Hazardous Liquid Pipeline O&M Cross Reference Table

FN: Liquid O&M x-ref, v2016
Updated: Sept 2016

Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
107	195.402(d)(3)	F	Operations & Maintenance	Abnormal Operations - correcting variations	PSOM		
108	195.402(d)(4)	F	Operations & Maintenance	Abnormal Operations - notification process	PSOM		
109	195.402(d)(5)	F	Operations & Maintenance	Abnormal Operations - periodic review to response	PSOM		
110	195.402(e)(1)	F	Operations & Maintenance	Em. Plan - receiving, identifying, classifying	Em Plan		
111	195.402(e)(2)	F	Operations & Maintenance	Em. Plan - prompt and effective response	Em Plan		
112	195.402(e)(3)	F	Operations & Maintenance	Em. Plan - personnel and equipment available resources	Em Plan		
113	195.402(e)(4)	F	Operations & Maintenance	Em. Plan - taking action to minimize release	Em Plan		
114	195.402(e)(5)	F	Operations & Maintenance	Em. Plan - controlling release	Em Plan		
115	195.402(e)(6)	F	Operations & Maintenance	Em. Plan - minimizing public exposure	Em Plan		
116	195.402(e)(7)	F	Operations & Maintenance	Em. Plan - notifying fire and police and HVL preplanned response	Em Plan		
117	195.402(e)(8)	F	Operations & Maintenance	Em. Plan - determining extend of hvl vapor cloud with instrument	Em Plan		
118	195.402(e)(9)	F	Operations & Maintenance	Em. Plan - post accident review	Em Plan		
119	195.403(a)(1)	F	Operations & Maintenance	Emergency Response Training - carry out procedures	16.01		14.05
120	195.403(a)(2)	F	Operations & Maintenance	Emergency Response Training - know characteristics of hazards	16.01		
121	195.403(a)(3)	F	Operations & Maintenance	Emergency Response Training - recognize emergency conditions	16.01		
122	195.403(a)(4)	F	Operations & Maintenance	Emergency Response Training - take steps to minimize hazard	16.01		
123	195.403(a)(5)	F	Operations & Maintenance	Emergency Response Training - fire extinguishers	16.01		
124	195.403(b)(1)	F	Operations & Maintenance	Emergency Response Training - review personnel performance	16.01		
125	195.403(b)(2)	F	Operations & Maintenance	Emergency Response Training - make appropriate changes	16.01		
126	195.403(b)(3)	F	Operations & Maintenance	Emergency Response Training - supervisor knowledge & verification	16.01		
127	195.404(a)(1)	F	Operations & Maintenance	Maps and Records - location and ID of listed facilities	2.01		5.03, 6.08, 9.01
128	195.404(a)(2)	F	Operations & Maintenance	Maps and Records - list of crossings	2.01		5.03, 6.08, 9.02
129	195.404(a)(3)	F	Operations & Maintenance	Maps and Records - MOP	2.01		
130	195.404(a)(4)	F	Operations & Maintenance	Maps and Records - diameter, grade, type, WT of pipe	2.01		
131	195.404(b)	F	Operations & Maintenance	Maps and Records - 3 year records	2.01		
132	195.404(b)(1)	F	Operations & Maintenance	Maps and Records - discharge pressure at each pump station	2.01		
133	195.404(b)(2)	F	Operations & Maintenance	Maps and Records - abnormal operations	2.01		
134	195.404(c)(1)	F	Operations & Maintenance	Maps and Records - repair of pipes	2.01		
135	195.404(c)(2)	F	Operations & Maintenance	Maps and Records - repair of parts	2.01		
136	195.404(c)(3)	F	Operations & Maintenance	Maps and Records - Subpart F records	2.01		
137	195.405	F	Operations & Maintenance	Protection Against Ignitions and Safe Access/Egress Involving Floating Roofs	4.02		4.02
138	195.406	F	Operations & Maintenance	MOP - maximum MOP	7.02		8.01, 12.01, 15.01
139	195.406(a)(1)	F	Operations & Maintenance	MOP - pipe design	7.02		8.01, 12.01, 15.01
140	195.406(a)(2)	F	Operations & Maintenance	MOP - compenent design	7.02		8.01, 12.01, 15.01
141	195.406(a)(3)	F	Operations & Maintenance	MOP - 80% test pressure (subpart E)	7.02		8.01, 12.01, 15.01
142	195.406(a)(4)	F	Operations & Maintenance	MOP - 80% of factory test pressure	7.02		8.01, 12.01, 15.01
143	195.406(a)(5)	F	Operations & Maintenance	MOP- 80% of operating pressure	7.02		8.01, 12.01, 15.01
144	195.406(b)	F	Operations & Maintenance	MOP - may not exceed110%, controls and equipment in place	7.02		8.01, 12.01, 15.01
145	195.408(a)	F	Operations & Maintenance	Communications - For safe operations	3.06	5.1.1.13	3.04, 3.02, em plan
146	195.408(b)(1)	F	Operations & Maintenance	Communications - Monitoring operational data	3.06	5.1.1.13	
147	195.408(b)(2)	F	Operations & Maintenance	Communications - Receiving notices from the public	3.06	5.1.1.13	3.04, 3.02, em plan
148	195.408(b)(3)	F	Operations & Maintenance	Communications - 2 way comm between control rm and scene	3.06	5.1.1.13	3.04, 3.02, em plan
149	195.408(b)(4)	F	Operations & Maintenance	Communications - Comm. with fire and police	3.06	5.1.1.13	3.04, 3.02, em plan
150	195.410(a)(1)	F	Operations & Maintenance	Line Markers - location	5.04		
151	195.410(a)(2)	F	Operations & Maintenance	Line Markers - info on line marker	5.04		
152	195.410(c)	F	Operations & Maintenance	Line Markers - in locations accessible to public	5.04		

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Hazardous Liquid Pipeline O&M Cross Reference Table

FN: Liquid O&M x-ref, v2016
Updated: Sept 2016

Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
153	195.412(a)	F	Operations & Maintenance	Inspection of Rights-of-Way	5.03		
154	195.412(b)	F	Operations & Maintenance	Inspection of Crossings Under Navigable Waters	5.03		
155	195.413	F	Operations & Maintenance	Underwater Inspection and Reburial of Pipelines in The Gulf of Mexico and Its Inlets	NA	NA	NA
156	195.414-195.418	F	Operations & Maintenance	Reserved			
157	195.420(a)	F	Operations & Maintenance	Valve Maintenance - maintain in good working order	7.01		14.01, 14.02
158	195.420(b)	F	Operations & Maintenance	Valve Maintenance - inspection frequency	8.01		14.01, 14.03
159	195.420(c)	F	Operations & Maintenance	Valve Maintenance - protection from vandelism	9.01		14.01, 14.04
160	195.422(a)	F	Operations & Maintenance	Pipeline Repairs - in safe manner	9.06		8.02, 9.01, 9.05, 14.04
161	195.422(b)	F	Operations & Maintenance	Pipeline Repairs - designed and contructed to meet pipeline regs	10.06		8.02, 9.01, 9.05, 14.05
162	195.424(a)	F	Operations & Maintenance	Pipe Movement - reduction to 50% MOP	12.03		
163	195.424(b)(1)	F	Operations & Maintenance	Pipe Movement - HVLs (joined by welding), removed fluids	12.03		
164	195.424(b)(2)	F	Operations & Maintenance	Pipe Movement - HVL procedure to protect the public	12.03		
165	195.424(b)(3)	F	Operations & Maintenance	Pipe Movement - HVL pressure reduction	12.03		
166	195.424(c)(1)	F	Operations & Maintenance	Pipe Movement - HVLs (not joined by welding), removed fluids	12.03		
167	195.424(c)(2)	F	Operations & Maintenance	Pipe Movement - HVLs (not joined by welding), protect public	12.03		
168	195.424(c)(3)	F	Operations & Maintenance	Pipe Movement - HVLs (not joined by welding), isolate line	12.03		
169	195.426	F	Operations & Maintenance	Scraper and Sphere Facilities - relief valve on barrel	4.01		
170	196.426	F	Operations & Maintenance	Scraper and Sphere Facilities - barrell pressure indication of safety device	4.01		
171	195.428(a)	F	Operations & Maintenance	Overpressure Safety Devices & Overfill Protection System - inspection interval	4.02		
172	195.428(b)	F	Operations & Maintenance	Overpressure Safety Devices & Overfill Protection System - breakout tank interval	4.02		
173	195.428(c)	F	Operations & Maintenance	Overpressure Safety Devices & Overfill Protection System - overfill per API std	4.02		
174	195.428(d)	F	Operations & Maintenance	Overpressure Safety Devices & Overfill Protection System - overfill per API std	4.02		
175	195.430(a)	F	Operations & Maintenance	Firefighting Equipment - proper condition at all times	14.05		
176	195.430(b)	F	Operations & Maintenance	Firefighting Equipment - plainly marked	14.05		
177	195.430(c)	F	Operations & Maintenance	Firefighting Equipment - location	14.05		
178	195.432(a)	F	Operations & Maintenance	Breakout Tanks - Inspection	4.02		
179	195.432(b)	F	Operations & Maintenance	Breakout Tanks - Integrity inspection	4.02		
180	195.432(c)	F	Operations & Maintenance	Breakout Tanks - Integrity inspection	4.02		
181	195.432(d)	F	Operations & Maintenance	Breakout Tanks - Inspection intervals	4.02		
182	195.434	F	Operations & Maintenance	Signs - pump station signs	5.04		
183	196.434	F	Operations & Maintenance	Signs - info on signs	5.04		
184	195.436	F	Operations & Maintenance	Security of Facilities	4.03		14.01, 14.02
185	195.438	F	Operations & Maintenance	Smoking or Open Flames	4.03		14.03
186	195.440(d)	F	Operations & Maintenance	Public Awareness - educationing public, gov., and excavators with required info	3.03		
187	195.440(e)	F	Operations & Maintenance	Public Awareness - educationing cities, schools, businesses	3.03		
188	195.440(f)	F	Operations & Maintenance	Public Education - appropriate media type	3.03		
189	195.440(g)	F	Operations & Maintenance	Public Education - common language of area	3.03		
190	195.442(a)	F	Operations & Maintenance	Damage Prevention Program - Written Program	18.01	All	3.02
191	195.442(b)	F	Operations & Maintenance	Damage Prevention Program - One Call System Particaption	18.01	5.1	
192	195.442(c)(1)	F	Operations & Maintenance	Damage Prevention Program - ID excavators	18.01	5.2	
193	195.442(c)(2)	F	Operations & Maintenance	Damage Prevention Program - Notification to the public	18.01	5.3	
194	195.442(c)(3)	F	Operations & Maintenance	Damage Prevention Program - Receiving & recording excavations	18.01	5.4	
195	195.442(c)(4)	F	Operations & Maintenance	Damage Prevention Program - Notification to excavator	18.01	5.3	
196	195.442(c)(5)	F	Operations & Maintenance	Damage Prevention Program - Marking	18.01	5.6	
197	195.442(c)(6)	F	Operations & Maintenance	Damage Prevention Program - Onsite inspection	18.01	5.7	

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Hazardous Liquid Pipeline O&M Cross Reference Table

FN: Liquid O&M x-ref, v2016
Updated: Sept 2016

Line #	195 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
198	195.444	F	Operations & Maintenance	CPM Leak Detection	PSOM		
199	195.551	H	Corrosion Control	What do the regulations in the subpart cover?			
200	195.553	H	Corrosion Control	What special definitions apply to this subpart?			
201	195.555	H	Corrosion Control	What are the qualifications for supervisors?	16.01	4.1.9	
202	195.557	H	Corrosion Control	What pipelines must have coating for external corrosion control?	6.03		
203	195.557(a)	H	Corrosion Control	External corrosion control - deadlines for new, relocated pipe	6.03		
204	195.557(b)	H	Corrosion Control	External corrosion control - deadlines for conversion of service	6.03		
205	195.559	H	Corrosion Control	What coating material may I use for external corrosion control?	6.03		
206	195.561	H	Corrosion Control	When must I inspect pipe coating used for external corrosion control?	6.03		
207	195.561(a)	H	Corrosion Control	Coating inspections just prior to installation	6.03		
208	195.561(b)	H	Corrosion Control	Repair of coating	6.03		
209	195.563	H	Corrosion Control	Which pipelines must have cathodic protection?	6.03		
210	195.563(a)	H	Corrosion Control	CP installed within one year	6.05		
211	195.563(b)	H	Corrosion Control	CP for conversion of service	6.05		
212	195.563(c)	H	Corrosion Control	CP for other buried pipe with coating	6.05		
213	195.563(d)	H	Corrosion Control	CP based on surveys	6.05		
214	195.563(e)	H	Corrosion Control	CP for unprotected pipe	6.05		
215	195.565	H	Corrosion Control	How do install cathodic protection on breakout tanks?	6.05		
216	195.567	H	Corrosion Control	Which pipelines must have test leads and what must I do to install and maintain the test leads?	6.05		
217	195.569	H	Corrosion Control	Do I have to examine exposed portions of buried pipelines?	6.04		
218	195.571	H	Corrosion Control	What criteria must I use to determine the adequacy of CP?	6.05		
219	195.573	H	Corrosion Control	What must I do to monitor external corrosion?	6.05		
220	195.573(a)	H	Corrosion Control	Inspection frequency	6.05		
221	195.573(b)	H	Corrosion Control	Unprotected pipe surveys	6.05		
222	195.573(c)	H	Corrosion Control	Rectifier inspection frequency	6.07		
223	195.573(d)	H	Corrosion Control	Breakout tank CP inspection	6.05		
224	195.573(e)	H	Corrosion Control	Correction of deficiencies	6.05		
225	195.575	H	Corrosion Control	Which facilities must I electrically isolate and inspections, tests, and safegaurds are required?	6.06		
226	195.577	H	Corrosion Control	What must I do to alleviate interferance currents?	6.06		
227	195.579	H	Corrosion Control	What must I do to mitigate internal corrosion?	6.02		
228	195.579(a)	H	Corrosion Control	Internal Corrosion - investigation of corrosion properites and actions	6.02		
229	195.579(b)	H	Corrosion Control	Internal Corrosion - inhibitors, coupons, frequency of inspection	6.02		
230	195.579(c)	H	Corrosion Control	Internal Corrosion - internal pipe inspection when exposed	6.02		
231	195.581	H	Corrosion Control	Which pipelines must I protect against atmospheric corrosion and what coating material may I use?	6.01		
232	195.583	H	Corrosion Control	What must I do to monitor atmospheric corrosion?	6.01		
233	195.585	H	Corrosion Control	What must I do to correct corroded pipe?	6.05	7	6.01
234	195.587	H	Corrosion Control	What methods are available to determine the strength of corroded pipe?	6.05	7	6.01
235	195.589	H	Corrosion Control	What corrosion control information do I have to maintain?	6.08		All section #6

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Liquid Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

PROCEDURE	FORM	TITLE	Frequency
1.01	Chart 1.01A	External Reporting of Accidents, California	AR
1.01	Chart 1.01B	External Reporting of Accidents, Federal	AR
1.01	Form 1.01B	Incident and Service Interruption Report	AR
1.01	PHMSA 7000-1	PHMSA Accident Report – Hazardous Liquid Pipeline Form and instructions	AR
1.02	Chart 1.02A	Reporting of Safety Related Conditions	AR
1.02	Form 1.02B	Safety Related Condition Report	AR
1.03	Form 1.03A	Accident & Near Miss Investigation Report	AR
1.03	Form 1.03B	Failure Investigation Form (PHMSA Form #11)	AR
1.03	Form 1.03C	Chain of Custody	AR
1.04	Form 1.04A	Hazardous Liquid Jurisdictional Determination	AR
1.05	PHMSA #7000-1.1	Annual Report – Hazardous Liquid Pipelines and Instructions	1x/yr (by June 15)
1.08	PHMSA #1000-1	PHMSA OPID Assignment Request and Instructions	AR
3.01	Form 3.01B	Pipeline Maintenance and Surveillance Form	Various
4.02	Form 4.02A	Breakout Tank Inspection and Testing Form	1x/yr
5.01	Form 5.01A	Continuing Surveillance Review	1x/yr
5.03	Form 5.03A	Pipeline Inspection Report	26x/yr
5.03	Form 5.03C	Navigable Waterway Crossing Inspection Report	1x/5yr

Liquid Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

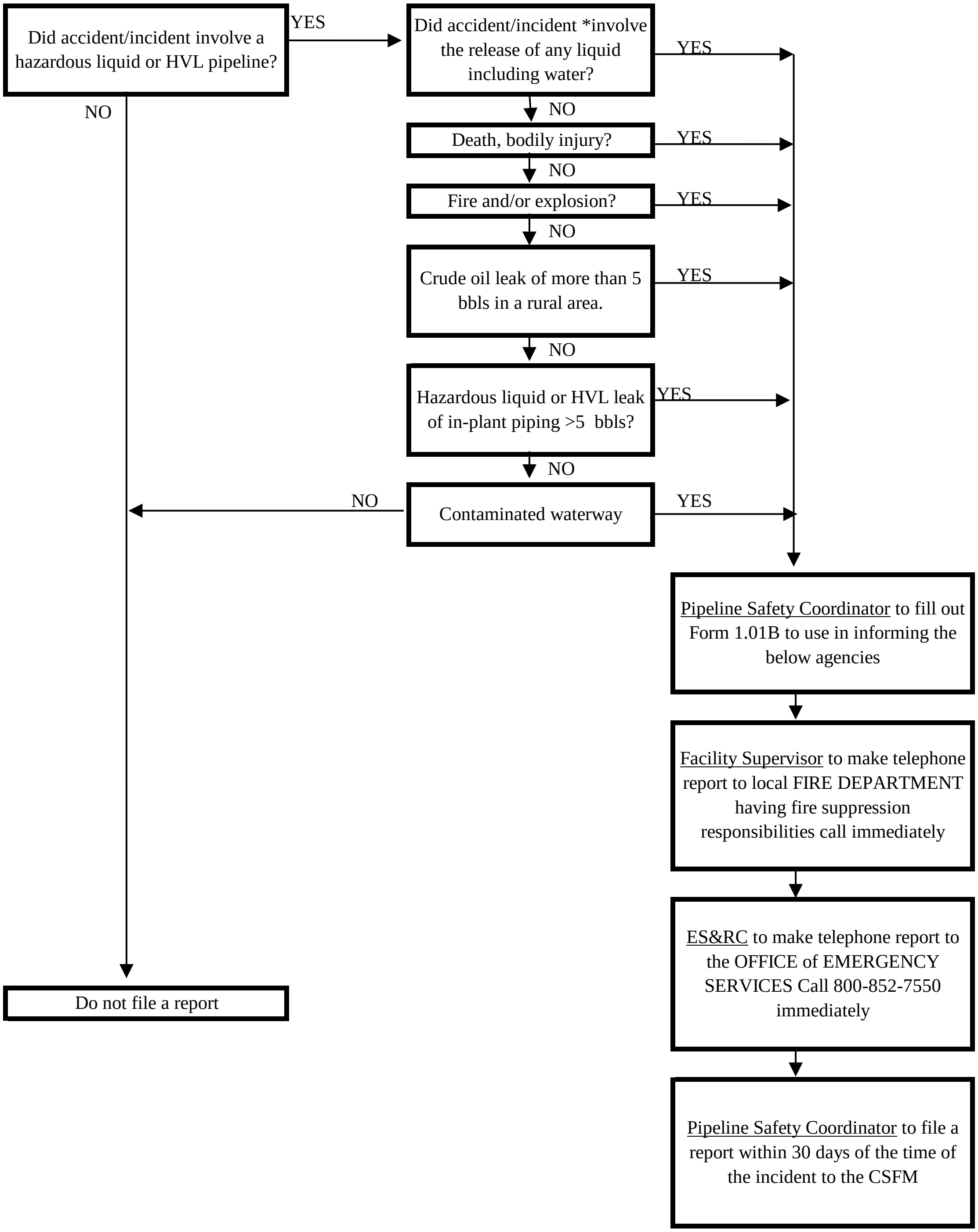
PROCEDURE	FORM	TITLE	Frequency
6.01	Form 6.01A	External Corrosion Test for Above Ground Facilities (atmospheric corrosion)	1x/yr (offshore) 1x/3yr (onshore)
6.02	Form 6.02A	Coupon Monitoring	2x/yr
6.05	Form 6.05A	CP System Record (Pipe to Soil)	1x/yr
6.05	Form 6.05B	Critical Bonds	6x/yr
6.07	Form 6.07A	Rectifier Readings	6x/yr
6.09	Form 6.09A	Unprotected Pipeline Inspection Report	1x/yr
6.10	Form 6.10A	Annual Corrosion Review	1x/yr
7.01	Form 7.01A	Emergency Valve Inspection Report	1x/yr
7.02	Form 7.02A	Relief Valve Report	1x/yr
7.02	Form 7.02B	Regulator Report	1x/yr
8.01	Form 8.01A	Pipeline Qualification Record	AR
8.01	8.01B template	MOP Calculation Template	AR
12.02	Form 12.02A	Conversion of Service Template	AR
13.01	Form 13.01A	Facility Abandonment Record	AR
14.05	Form 14.05A	Monthly Fire Extinguisher Inspections	Monthly
15.01	Form 15.01A	Hydrostatic Test Results	
15.01	Form 15.01B	Hydro Test Acceptability Form	

Liquid Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

PROCEDURE	FORM	TITLE	Frequency
16.01	Form 16.01A	Training Plan for Pipeline Personnel	AR
16.01	Form 16.01B	Annual Review of Emergency Training Objectives	
PSOM 17	PSOM Form #1A	Annual Review of Work Performed by Operator Tracking Form	1x/yr
PSOM 17	PSOM Form #1B	Review Work Performed by Operator Tracking Form	Ongoing
PSOM 17	PSOM Form #2	Abnormal Operations Report	AR
PSOM 17	PSOM Form #3	Training Registration	AR
PSOM 17	PSOM Form #4	Pipeline Management of Change (MOC)	AR
PSOM 18	Form 18.01-1	PA Annual Review for Implementation	1x/yr
PSOM 18	Form 18.01-2	PA Evaluation of Effectiveness	1x/4yr
PSOM 18	Form 18.01-3	PA Program Enhancements	1x/yr
PSOM 18	Form 18.01-4	PA Measures	1x/yr
PSOM 18	Form 18.01-5	PA Government Liaison Meeting	1x/yr
PSOM 18	Form 18.01-6	PA Agenda and Action Items	1x/yr
PSOM 18	Form 18.01-7	PA Team Charter	1x/yr
PSOM 18	Form 18.01-8	PA Record of Revisions	1x/yr
PSOM 18	PHMSA Form 21	PHMSA Public Awareness Inspection Form #21 with answers	NA

EXTERNAL REPORTING OF ACCIDENTS

CHART 1.01A - CAL

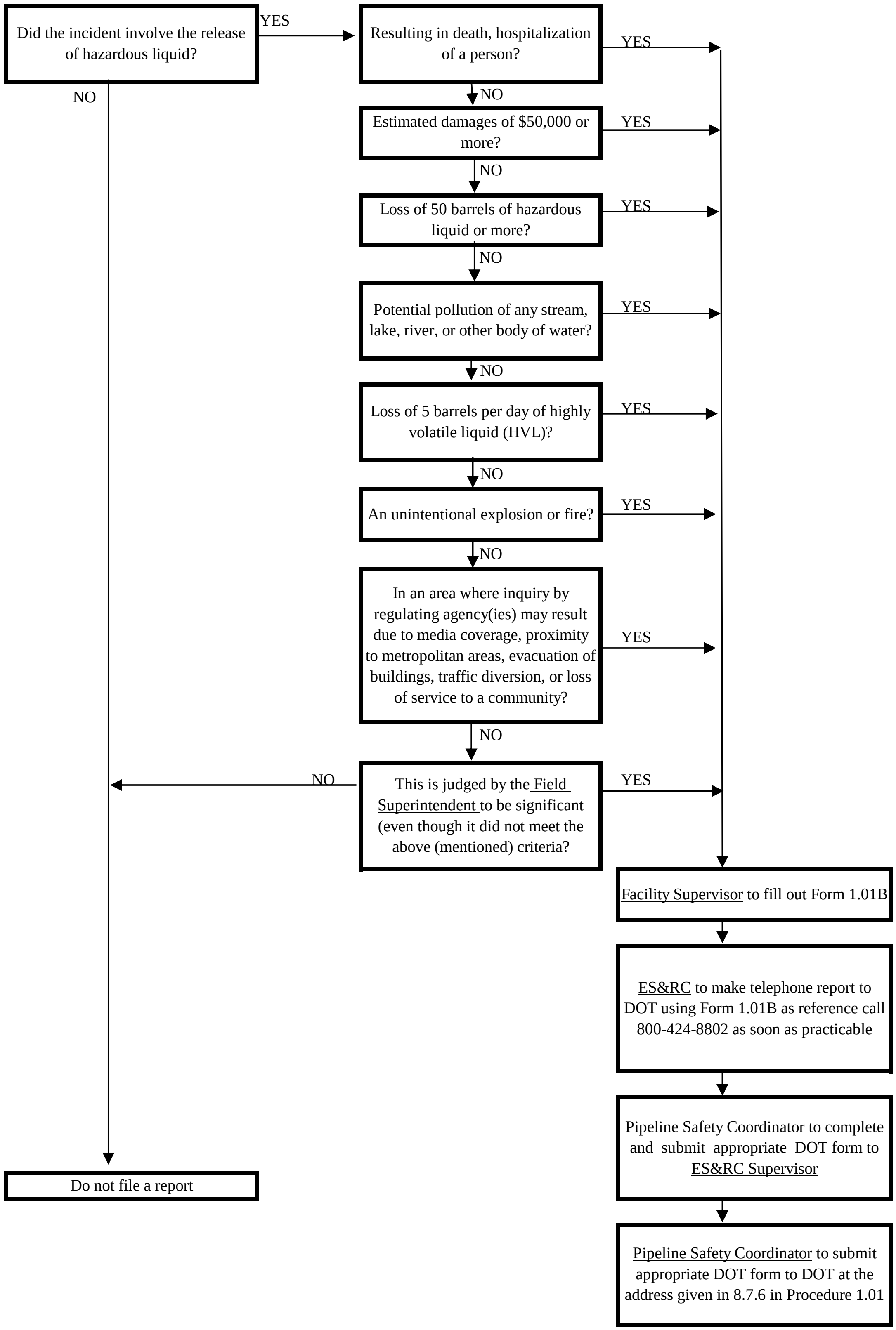


* <u>NOTE:</u> This includes any leak or rupture that occurs during hydrotest even using water.

EXTERNAL REPORTING OF ACCIDENTS

EXTERNAL REPORTING OF ACCIDENTS

CHART 1.01B - FEDERAL



TOC See Procedure 1.01, Section 8 for Internal Reporting of Incidents and for more details on External Reporting of Incidents.

INCIDENT AND SERVICE INTERRUPTION REPORT

FORM 1.01B

REPORTED BY:	REPORTED TO:	TIME:	DATE: ______ M0-DAY-YR
PHONE No.:	PHONE No.:		
COMPANY:	DISTRICT/LOCATION:	MEDIA ATTENTION	YES NO

Time/Location

PLANT:	PIPELINE NAME:		☐ Rural ☐ Non Rural ☐ Offshore
STATE:	COUNTY/ PARISH:	SEC.-TWN-RANGE:	☐ Gas ☐ Haz Liq

PIPELINE DATA		GATHERING		Size	Wall	Grade	MAOP	OP Pressure
	☐ Transmission ☐ Gathering	☐ D.O.T. Juris	☐ Non Juris					

Incident

		Yes	No		Yes	No
Release and Fatality	Employee ☐ Public ☐			Fire or Explosion		
Release and Injury	Employee ☐ Public ☐			Other significant Event		
Gas Release and Property Damage > $50,000 Haz Liquid Release > 50 bbls				Total Estimated Property Damage to Company and others $		

System Interruption

System Interruption ☐ Yes ☐ No	Estimated Length of System interruption		Hours		Minutes

System or Customer affected:

	DATE & TIME COMPLETED	EST. ACT.

Description & Apparent Cause

☐ Outside Force ☐ Corrosion ☐ Material Failure ☐ Construction Defect ☐ Other

DESCRIPTION AND APPARENT CAUSE: ______

Action Taken

Temporary measures to protect the public or maintain the system:

	DATE & TIME COMPLETED	EST. ACT.
Repair: ______	DATE & TIME REPAIR COMPLETED	EST. ACT.

Report Activity

Telephone Report	To ☐ DOT ☐ STATE ☐ OTHERS:		
	Reported By:	Date Reported:	Time Reported:
☑ Form PHMSA F 7100.1 ☐ Form DOT 7000-1	Reported By:		Date:

Distribution:

______

______

______

Signatures:

Completed By: ______

Supervisor: ______

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NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.

OMB NO: 2137-0047
EXPIRATION DATE: 01/31/2013

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date ______________

No. ______________
(DOT Use Only)

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. Public reporting for this collection of information is estimated to be approximately 10 hours per response (5 hours for a small release), including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline. Note: Certain low consequence accidents only require the information indicated in the shaded fields.*

PART A – KEY REPORT INFORMATION

*Report Type: *(select all that apply)* ☐ Original ☐ Supplemental ☐ Final

*1. Operator's OPS-issued Operator Identification Number (OPID): /__/__/__/__/__/

*2. Name of Operator: ____

*3. Address of Operator:

*3.a ____
(Street Address)

*3.b ____
(City)

*3.c State: /__/__/

*3.d Zip Code: /__/__/__/__/__/ - /__/__/__/__/

*4. Local time *(24-hr clock)* and date of the Accident:

/__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

*5. Location of Accident:

Latitude: /__/__/ . /__/__/__/__/__/

Longitude: - /__/__/__/ . /__/__/__/__/__/

6. National Response Center Report Number (if applicable):

/__/__/__/__/__/__/__/

7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):

/__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

*8. Commodity released: *(select only one, based on predominant volume released)*

☐ Crude Oil

☐ Refined and/or Petroleum Product (non-HVL) which is a Liquid at Ambient Conditions

○ Gasoline (non-Ethanol) ○ Diesel, Fuel Oil, Kerosene, Jet Fuel

○ Mixture of Refined Products (transmix or other mixture)

○ Other ⇨ Name: ______________________

☐ HVL or Other Flammable or Toxic Fluid which is a Gas at Ambient Conditions

○ Anhydrous Ammonia

○ LPG (Liquefied Petroleum Gas) / NGL (Natural Gas Liquid)

○ Other HVL ⇨ Name: ______________________

☐ CO_2 (Carbon Dioxide)

☐ Biofuel / Alternative Fuel (including ethanol blends)

○ Fuel Grade Ethanol ○ Ethanol Blend ⇨ % Ethanol: /__/__/

○ Biodiesel ⇨ Blend (e.g. B2, B20, B100): B/__/__/__/ ○ Other ⇨ Name: ______________________

*9. Estimated volume of commodity released unintentionally: /__/__/__/,/__/__/__/./__/__/ Barrels

10. Estimated volume of intentional and/or controlled release/blowdown: /__/__/__/,/__/__/__/./__/__/ Barrels

*11. Estimated volume of commodity recovered: /__/__/__/,/__/__/__/./__/__/ Barrels

TOC

*12. Were there fatalities? ○ Yes ○ No
If Yes, specify the number in each category:

*12.a Operator employees /___/___/___/___/

*12.b Contractor employees working for the Operator /___/___/___/___/

*12.c Non-Operator emergency responders /___/___/___/___/

*12.d Workers working on the right-of-way, but NOT associated with this Operator /___/___/___/___/

*12.e General public /___/___/___/___/

12.f Total fatalities (sum of above) /___/___/___/___/

*13. Were there injuries requiring inpatient hospitalization? ○ Yes ○ No
If Yes, specify the number in each category:

*13.a Operator employees /___/___/___/___/

*13.b Contractor employees working for the Operator /___/___/___/___/

*13.c Non-Operator emergency responders /___/___/___/___/

*13.d Workers working on the right-of-way, but NOT associated with this Operator /___/___/___/___/

*13.e General public /___/___/___/___/

13.f Total injuries (sum of above) /___/___/___/___/

14. Was the pipeline/facility shut down due to the Accident?
○ Yes ○ No ⇨ Explain: ____________________

If Yes, complete Questions 14.a and 14.b: *(use local time, 24-hr clock)*

14.a Local time and date of shutdown /___/___/___/___/ Hour /___/___/ Month /___/___/ Day /___/___/ Year

14.b Local time pipeline/facility restarted /___/___/___/___/ Hour /___/___/ Month /___/___/ Day /___/___/ Year ○ Still shut down* *(*Supplemental Report required)*

*15. Did the commodity ignite? ○ Yes ○ No

*16. Did the commodity explode? ○ Yes ○ No

17. Number of general public evacuated: /___/___/___/,/___/___/___/

18. Time sequence: *(use local time, 24-hour clock)*

18.a Local time Operator identified Accident /___/___/___/___/ Hour /___/___/ Month /___/___/ Day /___/___/ Year

18.b Local time Operator resources arrived on site /___/___/___/___/ Hour /___/___/ Month /___/___/ Day /___/___/ Year

PART B – ADDITIONAL LOCATION INFORMATION

*1. Was the origin of the Accident onshore?
○ Yes *(Complete Questions 2-12)* ○ No *(Complete Questions 13-15)*

If **Onshore**:

*2. State: /___/___/

*3. Zip Code: /___/___/___/___/___/ - /___/___/___/___/

4. ______________________ City

5 ______________________ County or Parish

6. Operator-designated location: *(select only one)*
☐ Milepost/Valve Station *(specify in shaded area below)*
☐ Survey Station No. *(specify in shaded area below)*

/___/___/___/___/___/___/___/___/___/___/___/___/___/___/

7. Pipeline/Facility name: ______________________________

8. Segment name/ID: ______________________________

*9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)? ○ Yes ○ No

*10. Location of Accident: *(select only one)*
☐ Totally contained on Operator-controlled property
☐ Originated on Operator-controlled property, but then flowed or migrated off the property
☐ Pipeline right-of-way

*11. Area of Accident (as found): *(select only one)*
☐ Tank, including attached appurtenances
☐ Underground ⇨ Specify: ○ Under soil
○ Under a building ○ Under pavement
○ Exposed due to excavation
○ In underground enclosed space (e.g., vault)
○ Other ______________________________
Depth-of-Cover (in): /___/,/___/___/___/
☐ Aboveground ⇨ Specify:
○ Typical aboveground facility piping or appurtenance
○ Overhead crossing
○ In or spanning an open ditch
○ Inside a building ○ Inside other enclosed space
○ Other ______________________________
☐ Transition Area ⇨ Specify: ○ Soil/air interface ○ Wall sleeve ○ Pipe support or other close contact area
○ Other ______________________________

*12. Did Accident occur in a crossing?: ○ Yes ○ No
If Yes, specify type below:
☐ Bridge crossing ⇨ Specify: ○ Cased ○ Uncased
☐ Railroad crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Road crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Water crossing
⇨ Specify: ○ Cased ○ Uncased
Name of body of water, if commonly known:
____
Approx. water depth (ft) at the point of the Accident:
/___/,/___/___/___/
(select only one of the following)
○ Shoreline/Bank crossing
○ Below water, pipe in bored/drilled crossing
○ Below water, pipe buried below bottom (NOT in bored/drilled crossing)
○ Below water, pipe on or above bottom

If **Offshore**:

*13. Approximate water depth (ft.) at the point of the Accident:
/___/___/,/___/___/___/

*14. Origin of Accident:
☐ In State waters
⇨ Specify: State: /___/___/
Area: ____________________
Block/Tract #: /___/___/___/___/
Nearest County/Parish: ________________
☐ On the Outer Continental Shelf (OCS)
⇨ Specify: Area: ____________________
Block #: /___/___/___/___/

*15. Area of Accident: *(select only one)*
☐ Shoreline/Bank crossing or shore approach
☐ Below water, pipe buried or jetted below seabed
☐ Below water, pipe on or above seabed
☐ Splash Zone of riser
☐ Portion of riser outside of Splash Zone, including riser bend
☐ Platform

PART C – ADDITIONAL FACILITY INFORMATION

*1. Is the pipeline or facility:
- ☐ Interstate
- ☐ Intrastate

*2. Part of system involved in Accident: *(select only one)*
- ☐ Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances ⇨ ○ Atmospheric or Low Pressure ○ Pressurized
- ☐ Onshore Terminal/Tank Farm Equipment and Piping
- ☐ Onshore Equipment and Piping Associated with Belowground Storage
- ☐ Onshore Pump/Meter Station Equipment and Piping
- ☐ Onshore Pipeline, Including Valve Sites
- ☐ Offshore Platform/Deepwater Port, Including Platform-mounted Equipment and Piping
- ☐ Offshore Pipeline, Including Riser and Riser Bend

*3. Item involved in Accident: *(select only one)*

☐ Pipe ⇨ Specify: ○ Pipe Body ○ Pipe Seam

3.a Nominal diameter of pipe (in): /___/___/./___/___/___/

3.b Wall thickness (in): /___/./___/___/___/

3.c SMYS (Specified Minimum Yield Strength) of pipe (psi): /___/___/___/,/___/___/___/

3.d Pipe specification: ______________________________

3.e Pipe Seam ⇨ Specify: ○ Longitudinal ERW - High Frequency ○ Single SAW ○ Flash Welded ○ Longitudinal ERW - Low Frequency ○ DSAW ○ Continuous Welded ○ Longitudinal ERW – Unknown Frequency ○ Furnace Butt Welded ○ Spiral Welded ERW ○ Spiral Welded SAW ○ Spiral Welded DSAW ○ Lap Welded ○ Seamless ○ Other _________________________

3.f Pipe manufacturer: ________________________________

3.g Year of manufacture: /___/___/___/___/

3.h Pipeline coating type at point of Accident

⇨ Specify: ○ Fusion Bonded Epoxy ○ Coal Tar ○ Asphalt ○ Polyolefin ○ Extruded Polyethylene ○ Field Applied Epoxy ○ Cold Applied Tape ○ Paint ○ Composite ○ None ○ Other ______________________________

☐ Weld, including heat-affected zone ⇨ Specify: ○ Pipe Girth Weld ○ Other Butt Weld ○ Fillet Weld ○ Other_____________

☐ Valve ○ Mainline ⇨ Specify: ○ Butterfly ○ Check ○ Gate ○ Plug ○ Ball ○ Globe ○ Other _________________________

3.i Mainline valve manufacturer: ______________________________

3.j Year of manufacture: /___/___/___/___/

○ Relief Valve
○ Auxiliary or Other Valve

- ☐ Pump
- ☐ Meter/Prover
- ☐ Scraper/Pig Trap
- ☐ Sump/Separator
- ☐ Repair Sleeve or Clamp
- ☐ Hot Tap Equipment
- ☐ Stopple Fitting
- ☐ Flange
- ☐ Relief Line
- ☐ Auxiliary Piping (e.g. drain lines)
- ☐ Tubing
- ☐ Instrumentation
- ☐ Tank/Vessel ⇨ Specify: ○ Single Bottom System ○ Double Bottom System ○ Tank Shell ○ Chime ○ Roof/Roof Seal ○ Roof Drain System ○ Mixer ○ Pressure Vessel Head or Wall ○ Appurtenance ○ Other ________________________________
- ☐ Other ___________________________________

4. Year item involved in Accident was installed: /___/___/___/___/

*5. Material involved in Accident: (*select only one)*

- ☐ Carbon Steel
- ☐ Material other than Carbon Steel ⇨ Specify: ____

*6. Type of Accident involved: *(select only one)*

- ☐ Mechanical Puncture ⇨ Approx. size: /__/__/__/__/__/./__/in. (axial) by /__/__/__/__/__/./__/in. (circumferential)
- ☐ Leak ⇨ Select Type: ○ Pinhole ○ Crack ○ Connection Failure ○ Seal or Packing ○ Other
- ☐ Rupture ⇨ Select Orientation: ○ Circumferential ○ Longitudinal ○ Other ________________________________
  Approx. size: /__/__/__/__/__/./__/ in. (widest opening) by /__/__/__/__/__/__/./__/in. (length circumferentially or axially)
- ☐ Overfill or Overflow
- ☐ Other ⇨ Describe: ____

PART D – ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact: O Yes O No
   1.a If Yes, specify all that apply:
   - ☐ Fish/aquatic
   - ☐ Birds
   - ☐ Terrestrial

*2. Soil contamination: O Yes O No

3. Long term impact assessment performed or planned: O Yes O No

4. Anticipated remediation: O Yes O No (not needed)
   4.a If Yes, specify all that apply:
   ☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

*5. Water contamination: O Yes ⇨ *(Complete 5.a – 5.c below)* O No
   *5.a Specify all that apply:
   - ☐ Ocean/Seawater
   - ☐ Surface
   - ☐ Groundwater
   - ☐ Drinking water ⇨ *(Select one or both)* O Private Well O Public Water Intake

   *5.b Estimated amount released in or reaching water: /__/__/__/,/__/__/__/./__/__/ Barrels

   *5.c Name of body of water, if commonly known: ____

*6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program? O Yes O No

*7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? O Yes O No

7.a If Yes, specify HCA type(s): *(select all that apply)*
- ☐ Commercially Navigable Waterway
  Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
  O Yes O No
- ☐ High Population Area
  Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
  O Yes O No
- ☐ Other Populated Area
  Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
  O Yes O No
- ☐ Unusually Sensitive Area (USA) – Drinking Water
  Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
  O Yes O No
- ☐ Unusually Sensitive Area (USA) – Ecological
  Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
  O Yes O No

*8. Estimated cost to Operator:

8.a Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ /__/__/__/,/__/__/__/,/__/__/__/
8.b Estimated cost of commodity lost	$ /__/__/__/,/__/__/__/,/__/__/__/
8.c Estimated cost of Operator's property damage & repairs	$ /__/__/__/,/__/__/__/,/__/__/__/
8.d Estimated cost of Operator's emergency response	$ /__/__/__/,/__/__/__/,/__/__/__/
8.e Estimated cost of Operator's environmental remediation	$ /__/__/__/,/__/__/__/,/__/__/__/
8.f Estimated other costs	$ /__/__/__/,/__/__/__/,/__/__/__/
Describe ____	
8.g Estimated total costs (sum of above)	$ /__/__/__/,/__/__/__/,/__/__/__/

PART E – ADDITIONAL OPERATING INFORMATION

*1. Estimated pressure at the point and time of the Accident (psig): /__/__/,/__/__/__/

*2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig) : /__/__/,/__/__/__/

*3. Describe the pressure on the system or facility relating to the Accident: *(select only one)*
- ☐ Pressure did not exceed MOP
- ☐ Pressure exceeded MOP, but did not exceed 110% of MOP
- ☐ Pressure exceeded 110% of MOP

*4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?
- ☐ No
- ☐ Yes ⇨ (*Complete 4.a and 4.b below)*

*4.a Did the pressure exceed this established pressure restriction? ○ Yes ○ No

*4.b Was this pressure restriction mandated by PHMSA or the State? ○ PHMSA ○ State ○ Not mandated

*5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?
- ☐ No
- ☐ Yes ⇨ (*Complete 5.a – 5.f below)*

5.a Type of upstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled

5.b Type of downstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled ○ Check Valve

5.c Length of segment initially isolated between valves (ft): /__/__/__/,/__/__/__/

5.d Is the pipeline configured to accommodate internal inspection tools?
- ☐ Yes
- ☐ No ⇨ Which physical features limit tool accommodation? *(select all that apply)*
  - ○ Changes in line pipe diameter
  - ○ Presence of unsuitable mainline valves
  - ○ Tight or mitered pipe bends
  - ○ Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)
  - ○ Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)
  - ○ Other ⇨ Describe:________________________________

5.e For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?
- ☐ No
- ☐ Yes ⇨ Which operational factors complicate execution? *(select all that apply)*
  - ○ Excessive debris or scale, wax, or other wall build-up
  - ○ Low operating pressure(s)
  - ○ Low flow or absence of flow
  - ○ Incompatible commodity
  - ○ Other ⇨ Describe:________________________________

5.f Function of pipeline system: *(select only one)*
- ☐ > 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS "Unregulated" Trunkline/Transmission
- ☐ > 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS "Unregulated" Gathering

*6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?

☐ No

☐ Yes ⇨ 6.a Was it operating at the time of the Accident? ○ Yes ○ No

6.b Was it fully functional at the time of the Accident? ○ Yes ○ No

6.c Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No

6.d Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No

*7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?

☐ No

☐ Yes ⇨ 7.a Was it operating at the time of the Accident? ○ Yes ○ No

7.b Was it fully functional at the time of the Accident? ○ Yes ○ No

7.c Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No

7.d Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No

*8. How was the Accident initially identified for the Operator? *(select only one)*

☐ CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)

☐ Static Shut-in Test or Other Pressure or Leak Test

☐ Controller

☐ Local Operating Personnel, including contractors

☐ Air Patrol

☐ Ground Patrol by Operator or its contractor

☐ Notification from Public

☐ Notification from Emergency Responder

☐ Notification from Third Party that caused the Accident

☐ Other ______________________________

*8.a If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify the following: *(select only one)*

○ Operator employee ○ Contractor working for the Operator

*9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident? *(select only one)*

☐ Yes, but the investigation of the control room and/or controller actions has not yet been completed by the Operator *(Supplemental Report required)*

☐ No, the facility was not monitored by a controller(s) at the time of the Accident

☐ No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the Operator did not investigate)*

____

____

____

☐ Yes, specify investigation result(s): *(select all that apply)*

○ Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue

○ Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue *(provide an explanation for why not)*

____

____

____

○ Investigation identified no control room issues

○ Investigation identified no controller issues

○ Investigation identified incorrect controller action or controller error

○ Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response

○ Investigation identified incorrect procedures

○ Investigation identified incorrect control room equipment operation

○ Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response

○ Investigation identified areas other than those above ⇨ Describe: ______________________________

____

____

____

PART F – DRUG & ALCOHOL TESTING INFORMATION	

*1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

- ○ No
- ○ Yes ⇨ *1.a Specify how many were tested: /__/__/
  - *1.b Specify how many failed: /__/__/

*2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

- ○ No
- ○ Yes ⇨ *2.a Specify how many were tested: /__/__/
  - *2.b Specify how many failed: /__/__/

PART G – APPARENT CAUSE	***Select only one box from PART G in the shaded column on the left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing, or root causes of the Accident in the narrative (PART H).***
G1 - Corrosion Failure – *only one **sub-cause** can be picked from shaded left-hand column	
☐ **External Corrosion**	*1. Results of visual examination: ○ Localized Pitting ○ General Corrosion ○ Other ______ *2. Type of corrosion: *(select all that apply)* ○ Galvanic ○ Atmospheric ○ Stray Current ○ Microbiological ○ Selective Seam ○ Other ______ *3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)* ○ Field examination ○ Determined by metallurgical analysis ○ Other ______ *4. Was the failed item buried under the ground? ○ Yes ⇨ *4.a Was failed item considered to be under cathodic protection at the time of the Accident? ○ Yes ⇨ Year protection started: /__/__/__/__/ ○ No *4.b Was shielding, tenting, or disbonding of coating evident at the point of the Accident? ○ Yes ○ No *4.c Has one or more Cathodic Protection Survey been conducted at the point of the Accident? ○ Yes, CP Annual Survey ⇨ Most recent year conducted: /__/__/__/__/ ○ Yes, Close Interval Survey ⇨ Most recent year conducted: /__/__/__/__/ ○ Yes, Other CP Survey ⇨ Most recent year conducted: /__/__/__/__/ ○ No ○ No ⇨ 4.d Was the failed item externally coated or painted? ○ Yes ○ No *5. Was there observable damage to the coating or paint in the vicinity of the corrosion? ○ Yes ○ No
☐ **Internal Corrosion**	*6. Results of visual examination: ○ Localized Pitting ○ General Corrosion ○ Not cut open ○ Other ______ *7. Cause of corrosion: *(select all that apply)* ○ Corrosive Commodity ○ Water drop-out/Acid ○ Microbiological ○ Erosion ○ Other ______ *8. The cause(s) of corrosion selected in Question 7 is based on the following: *(select all that apply)* ○ Field examination ○ Determined by metallurgical analysis ○ Other ______ *9. Location of corrosion: *(select all that apply)* ○ Low point in pipe ○ Elbow ○ Other______ *10. Was the commodity treated with corrosion inhibitors or biocides? ○ Yes ○ No 11. Was the interior coated or lined with protective coating? ○ Yes ○ No 12. Were cleaning/dewatering pigs (or other operations) routinely utilized? ○ Not applicable - Not mainline pipe ○ Yes ○ No 13. Were corrosion coupons routinely utilized? ○ Not applicable - Not mainline pipe ○ Yes ○ No
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel. 14. List the year of the most recent inspections: 14.a API Std 653 Out-of-Service Inspection /__/__/__/__/ ○ No Out-of-Service Inspection completed 14.b API Std 653 In-Service Inspection /__/__/__/__/ ○ No In-Service Inspection completed	

Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.

15. Has one or more internal inspection tool collected data at the point of the Accident?
    O Yes O No

    15.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:
    - O Magnetic Flux Leakage Tool /___/___/___/___/
    - O Ultrasonic /___/___/___/___/
    - O Geometry /___/___/___/___/
    - O Caliper /___/___/___/___/
    - O Crack /___/___/___/___/
    - O Hard Spot /___/___/___/___/
    - O Combination Tool /___/___/___/___/
    - O Transverse Field/Triaxial /___/___/___/___/
    - O Other ________________________ /___/___/___/___/

16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?
    O Yes ⇨ Most recent year tested: /___/___/___/___/ Test pressure (psig): /___/___/___/___/___/
    O No

17. Has one or more Direct Assessment been conducted on this segment?
    O Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /___/___/___/___/
    O Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /___/___/___/___/
    O No

18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?
    O Yes O No

    18.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:
    - O Radiography /___/___/___/___/
    - O Guided Wave Ultrasonic /___/___/___/___/
    - O Handheld Ultrasonic Tool /___/___/___/___/
    - O Wet Magnetic Particle Test /___/___/___/___/
    - O Dry Magnetic Particle Test /___/___/___/___/
    - O Other ________________________ /___/___/___/___/

G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Earth Movement, NOT due to Heavy Rains/Floods**	1. Specify: O Earthquake O Subsidence O Landslide O Other __________________
☐ **Heavy Rains/Floods**	2. Specify: O Washout/Scouring O Flotation O Mudslide O Other ________________
☐ **Lightning**	3. Specify: O Direct hit O Secondary impact such as resulting nearby fires
☐ **Temperature**	4. Specify: O Thermal Stress O Frost Heave O Frozen Components O Other ______________________________
☐ **High Winds**	
☐ **Other Natural Force Damage**	*5. Describe: ____

Complete the following if any Natural Force Damage sub-cause is selected.

*6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event? O Yes O No

*6.a If Yes, specify: (*select all that apply*) O Hurricane O Tropical Storm O Tornado O Other ____________________________

G3 – Excavation Damage - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Excavation Damage by Operator (First Party)**	
☐ **Excavation Damage by Operator's Contractor (Second Party)**	
☐ **Excavation Damage by Third Party**	
☐ **Previous Damage due to Excavation Activity**	**Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.** 1. Has one or more internal inspection tool collected data at the point of the Accident? O Yes O No 1.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: O Magnetic Flux Leakage /__/__/__/__/ O Ultrasonic /__/__/__/__/ O Geometry /__/__/__/__/ O Caliper /__/__/__/__/ O Crack /__/__/__/__/ O Hard Spot /__/__/__/__/ O Combination Tool /__/__/__/__/ O Transverse Field/Triaxial /__/__/__/__/ O Other ____________________ /__/__/__/__/ 2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? O Yes O No 3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident? O Yes ⇨ Most recent year tested: /__/__/__/__/ Test pressure (psig): /__/__/,/__/__/__/ O No 4. Has one or more Direct Assessment been conducted on the pipeline segment? O Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /__/__/__/__/ O Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /__/__/__/__/ O No 5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002? O Yes O No 5.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: O Radiography /__/__/__/__/ O Guided Wave Ultrasonic /__/__/__/__/ O Handheld Ultrasonic Tool /__/__/__/__/ O Wet Magnetic Particle Test /__/__/__/__/ O Dry Magnetic Particle Test /__/__/__/__/ O Other ________________________ /__/__/__/__/

Complete the following if Excavation Damage by Third Party is selected as the sub-cause.

6. Did the Operator get prior notification of the excavation activity? O Yes O No

*6.a If Yes, Notification received from: *(select all that apply)* O One-Call System O Excavator O Contractor O Landowner

Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.

7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)? ○ Yes ○ No

*8. Right-of-Way where event occurred: *(select all that apply)*

- ☐ Public ⇨ Specify: ○ City Street ○ State Highway ○ County Road ○ Interstate Highway ○ Other
- ☐ Private ⇨ Specify: ○ Private Landowner ○ Private Business ○ Private Easement
- ☐ Pipeline Property/Easement
- ☐ Power/Transmission Line
- ☐ Railroad
- ☐ Dedicated Public Utility Easement
- ☐ Federal Land
- ☐ Data not collected
- ☐ Unknown/Other

*9. Type of excavator: *(select only one)*

○ Contractor ○ County ○ Developer ○ Farmer ○ Municipality ○ Occupant
○ Railroad ○ State ○ Utility ○ Data not collected ○ Unknown/Other

*10. Type of excavation equipment: *(select only one)*

○ Auger ○ Backhoe/Trackhoe ○ Boring ○ Drilling ○ Directional Drilling
○ Explosives ○ Farm Equipment ○ Grader/Scraper ○ Hand Tools ○ Milling Equipment
○ Probing Device ○ Trencher ○ Vacuum Equipment ○ Data not collected ○ Unknown/Other

*11. Type of work performed: *(select only one)*

○ Agriculture ○ Cable TV ○ Curb/Sidewalk ○ Building Construction ○ Building Demolition
○ Drainage ○ Driveway ○ Electric ○ Engineering/Surveying ○ Fencing
○ Grading ○ Irrigation ○ Landscaping ○ Liquid Pipeline ○ Milling
○ Natural Gas ○ Pole ○ Public Transit Authority ○ Railroad Maintenance ○ Road Work
○ Sewer (Sanitary/Storm) ○ Site Development ○ Steam ○ Storm Drain/Culvert ○ Street Light
○ Telecommunications ○ Traffic Signal ○ Traffic Sign ○ Water ○ Waterway Improvement
○ Data not collected ○ Unknown/Other

*12. Was the One-Call Center notified? ○ Yes ○ No

*12.a If Yes, specify ticket number: /_/_/_/_/_/_/_/_/_/_/_/_/_/_/_/_/_/_/_/

*12.b If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:
____

*13. Type of Locator: ○ Utility Owner ○ Contract Locator ○ Data not collected ○ Unknown/Other

*14. Were facility locate marks visible in the area of excavation? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*15. Were facilities marked correctly? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16. Did the damage cause an interruption in service? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16.a If Yes, specify duration of the interruption: /___/___/___/___/ hours

(This CGA-DIRT section continued on next page with Question 17.)

*17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*:

- ☐ One-Call Notification Practices Not Sufficient: *(select only one)*
  - ○ No notification made to the One-Call Center
  - ○ Notification to One-Call Center made, but not sufficient
  - ○ Wrong information provided
- ☐ Locating Practices Not Sufficient: *(select only one)*
  - ○ Facility could not be found/located
  - ○ Facility marking or location not sufficient
  - ○ Facility was not located or marked
  - ○ Incorrect facility records/maps
- ☐ Excavation Practices Not Sufficient: *(select only one)*
  - ○ Excavation practices not sufficient (other)
  - ○ Failure to maintain clearance
  - ○ Failure to maintain the marks
  - ○ Failure to support exposed facilities
  - ○ Failure to use hand tools where required
  - ○ Failure to verify location by test-hole (pot-holing)
  - ○ Improper backfilling
- ☐ One-Call Notification Center Error
- ☐ Abandoned Facility
- ☐ Deteriorated Facility
- ☐ Previous Damage
- ☐ Data Not Collected
- ☐ Other / None of the Above *(explain)* ____________________

____
____
____

G4 - Other Outside Force Damage - ***only one sub-cause** can be picked from shaded left-hand column	
☐ **Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Accident**	
☐ **Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation**	1. Vehicle/Equipment operated by: *(select only one)* ○ Operator ○ Operator's Contractor ○ Third Party
☐ **Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring**	2. Select one or more of the following IF an extreme weather event was a factor: ○ Hurricane ○ Tropical Storm ○ Tornado ○ Heavy Rains/Flood ○ Other ______________________________
☐ **Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation**	
☐ **Electrical Arcing from Other Equipment or Facility**	
☐ **Previous Mechanical Damage NOT Related to Excavation**	**Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.** 3. Has one or more internal inspection tool collected data at the point of the Accident? ○ Yes ○ No 3.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: ○ Magnetic Flux Leakage /___/___/___/___/ ○ Ultrasonic /___/___/___/___/ ○ Geometry /___/___/___/___/ ○ Caliper /___/___/___/___/ ○ Crack /___/___/___/___/ ○ Hard Spot /___/___/___/___/ ○ Combination Tool /___/___/___/___/ ○ Transverse Field/Triaxial /___/___/___/___/ ○ Other ____________________ /___/___/___/___/ 4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? ○ Yes ○ No 5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident? ○ Yes ⇨ Most recent year tested: /___/___/___/___/ Test pressure (psig): /___/___/,/___/___/___/ ○ No 6. Has one or more Direct Assessment been conducted on the pipeline segment? ○ Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /___/___/___/___/ ○ Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /___/___/___/___/ ○ No *(This section continued on next page with Question 7.)*

	7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002? ○ Yes ○ No 7.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: ○ Radiography /__/__/__/__/ ○ Guided Wave Ultrasonic /__/__/__/__/ ○ Handheld Ultrasonic Tool /__/__/__/__/ ○ Wet Magnetic Particle Test /__/__/__/__/ ○ Dry Magnetic Particle Test /__/__/__/__/ ○ Other ________________________ /__/__/__/__/
☐ **Intentional Damage**	8. Specify: ○ Vandalism ○ Terrorism ○ Theft of transported commodity ○ Theft of equipment ○ Other ____________________________________
☐ **Other Outside Force Damage**	*9. Describe: ____

G5 - Material Failure of Pipe or Weld	**Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."**
	*Only one **sub-cause** can be picked from shaded left-hand column

1. The sub-cause selected below is based on the following: *(select all that apply)*

☐ Field Examination ☐ Determined by Metallurgical Analysis ☐ Other Analysis_______________________

☐ Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*

☐ **Construction-, Installation-, or Fabrication-related** ☐ **Original Manufacturing-related (NOT girth weld or other welds formed in the field)**	2. List contributing factors: *(select all that apply)* ☐ Fatigue- or Vibration-related: ○ Mechanically-induced prior to installation (such as during transport of pipe) ○ Mechanical Vibration ○ Pressure-related ○ Thermal ○ Other ______________________________ ☐ Mechanical Stress ☐ Other ______________________________
☐ **Environmental Cracking-related**	3. Specify: ○ Stress Corrosion Cracking ○ Sulfide Stress Cracking ○ Hydrogen Stress Cracking ○ Other __________________________

Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.

*4. Additional factors: *(select all that apply)* ○ Dent ○ Gouge ○ Pipe Bend ○ Arc Burn ○ Crack ○ Lack of Fusion
○ Lamination ○ Buckle ○ Wrinkle ○ Misalignment ○ Burnt Steel
○ Other ______________________________

*5. Has one or more internal inspection tool collected data at the point of the Accident? ○ Yes ○ No

*5.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

○ Magnetic Flux Leakage Tool /__/__/__/__/
○ Ultrasonic /__/__/__/__/
○ Geometry /__/__/__/__/
○ Caliper /__/__/__/__/
○ Crack /__/__/__/__/
○ Hard Spot /__/__/__/__/
○ Combination Tool /__/__/__/__/
○ Transverse Field/Triaxial /__/__/__/__/
○ Other ______________________ /__/__/__/__/

*6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?
○ Yes ⇨ Most recent year tested: /__/__/__/__/ Test pressure (psig): /__/__/,/__/__/__/
○ No

*7. Has one or more Direct Assessment been conducted on the pipeline segment?
○ Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /__/__/__/__/
○ Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /__/__/__/__/
○ No

*8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?
○ Yes ○ No

*8.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

○ Radiography /__/__/__/__/
○ Guided Wave Ultrasonic /__/__/__/__/
○ Handheld Ultrasonic Tool /__/__/__/__/
○ Wet Magnetic Particle Test /__/__/__/__/
○ Dry Magnetic Particle Test /__/__/__/__/
○ Other ____________________________ /__/__/__/__/

G6 - Equipment Failure - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Malfunction of Control/Relief Equipment**	1. Specify: *(select all that apply)* ○ Control Valve ○ Instrumentation ○ SCADA ○ Communications ○ Block Valve ○ Check Valve ○ Relief Valve ○ Power Failure ○ Stopple/Control Fitting ○ ESD System Failure ○ Other ______
☐ **Pump or Pump-related Equipment**	2. Specify: ○ Seal/Packing Failure ○ Body Failure ○ Crack in Body ○ Appurtenance Failure ○ Other ______
☐ **Threaded Connection/Coupling Failure**	3. Specify: ○ Pipe Nipple ○ Valve Threads ○ Mechanical Coupling ○ Threaded Pipe Collar ○ Threaded Fitting ○ Other ______
☐ **Non-threaded Connection Failure**	4. Specify: ○ O-Ring ○ Gasket ○ Seal (NOT pump seal) or Packing ○ Other ______
☐ **Defective or Loose Tubing or Fitting**	
☐ **Failure of Equipment Body (except Pump), Tank Plate, or other Material**	
☐ **Other Equipment Failure**	*5. Describe: ______ ______

Complete the following if any Equipment Failure sub-cause is selected.

*6. Additional factors that contributed to the equipment failure: *(select all that apply)*

- ○ Excessive vibration
- ○ Overpressurization
- ○ No support or loss of support
- ○ Manufacturing defect
- ○ Loss of electricity
- ○ Improper installation
- ○ Mismatched items (different manufacturer for tubing and tubing fittings)
- ○ Dissimilar metals
- ○ Breakdown of soft goods due to compatibility issues with transported commodity
- ○ Valve vault or valve can contributed to the release
- ○ Alarm/status failure
- ○ Misalignment
- ○ Thermal stress
- ○ Other ______

G7 - Incorrect Operation - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage**	
☐ **Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow**	1. Specify: ○ Valve misalignment ○ Incorrect reference data/calculation ○ Miscommunication ○ Inadequate monitoring ○ Other ______________
☐ **Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure**	
☐ **Pipeline or Equipment Overpressured**	
☐ **Equipment Not Installed Properly**	
☐ **Wrong Equipment Specified or Installed**	
☐ **Other Incorrect Operation**	*2. Describe: ______________

Complete the following if any Incorrect Operation sub-cause is selected.

*3. Was this Accident related to: *(select all that apply)*
- ○ Inadequate procedure
- ○ No procedure established
- ○ Failure to follow procedure
- ○ Other: ______________

*4. What category type was the activity that caused the Accident:
- ○ Construction
- ○ Commissioning
- ○ Decommissioning
- ○ Right-of-Way activities
- ○ Routine maintenance
- ○ Other maintenance
- ○ Normal operating conditions
- ○ Non-routine operating conditions (abnormal operations or emergencies)

*5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program? ○ Yes ○ No

*5.a If Yes, were the individuals performing the task(s) qualified for the task(s)?
- ○ Yes, they were qualified for the task(s)
- ○ No, but they were performing the task(s) under the direction and observation of a qualified individual
- ○ No, they were not qualified for the task(s) nor were they performing the task(s) under the direction and observation of a qualified individual

G8 – Other Accident Cause - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Miscellaneous**	*1. Describe: ______________
☐ **Unknown**	*2. Specify: ○ Investigation complete, cause of Accident unknown ○ Still under investigation, cause of Accident to be determined* *(*Supplemental Report required)*

PART H – NARRATIVE DESCRIPTION OF THE ACCIDENT	*(Attach additional sheets as necessary)*

*PART I – PREPARER AND AUTHORIZED SIGNATURE

*Preparer's Name (type or print)

Preparer's Telephone Number

Preparer's Title (type or print)

Preparer's E-mail Address

Preparer's Facsimile Number

Authorized Signature

*Date

Authorized Signature Telephone Number

*Authorized Signature's Name (type or print)

Authorized Signature's Title (type or print)

Authorized Signature's E-mail Address

GENERAL INSTRUCTIONS

Each operator of a hazardous liquid pipeline system shall file Form PHMSA F 7000-1 for an accident that meets the criteria in 49 CFR §195.50 as soon as practicable but not more than 30 days after discovery of the accident. Requirements for submitting reports are in §195.54 and §195.58.

Hazardous liquid releases during maintenance activities are not to be reported if the spill was less than 5 barrels, not otherwise reportable under 49 CFR §195.50, did not result in water pollution as described by 49 CFR §195.52(a)(4), was confined to company property or pipeline right-of-way, and was cleaned up promptly. Any spill of 5 gallons or more to water shall be reported.

Special considerations apply when a pipeline failure or release occurs involving secondary ignition. Secondary ignition is a fire where the origin of the fire is unrelated to the pipelines systems subject to Part 195, such as electrical fires, arson, etc., and includes events where fire or explosion not originating from a pipeline system failure or release was the primary *cause* of the pipeline system failure or release, such as a refinery fire that subsequently resulted in – but was not caused by – a hazardous liquid pipeline system failure or release. An accident caused by secondary ignition is not to be reported unless a release of hazardous liquid escaping from facilities subject to regulation under Part 195 results in one or more of the consequences as described in §195.50. The determination of consequences from a pipeline accident caused by secondary ignition, though, is an area of possible confusion when reporting accidents. This situation is particularly susceptible to confusion as compared to other Natural or Other Outside Force Damage because it is extremely difficult in most cases to establish whether and which consequences were attributable to the initiating fire (that is, the "secondary ignition" source itself) or to a subsequent fire due to a resulting pipeline system failure or release. PHMSA is providing the following guidance for operators to use when secondary ignition is involved (sometimes referred to as "Fire First" accidents):

- A pipeline accident attributed to secondary ignition is to be reported to PHMSA if any fatalities or injuries are involved unless it can be established with reasonable certainty that all of the casualties either preceded the pipeline system failure or release, or would have occurred whether or not the pipeline system failure or release occurred.
- A pipeline accident attributed to secondary ignition is NOT to be reported to PHMSA unless the damage to facilities subject to Part 195 exceeds $50,000.

These considerations apply to several pipeline accident cause categories as indicated in pertinent sections of these instructions.

PHMSA requires electronic reporting. Follow these instructions for electronic filing or to request an alternative reporting method. If you have questions about this report or these instructions, contact PHMSA's Information Resources Manager at 202-366-8075. If you need copies of Form PHMSA F 7000-1 and/or instructions they can be found on the

Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking the Library hyperlink and then selecting the Forms link under the "Mini-Menu" on the right side of the page. The applicable forms are listed in the section titled Accidents/Incidents/Annual Reporting Forms.

195.50 Reporting accidents.

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator.

(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

> **(1) Not otherwise reportable under this section;**
>
> **(2) Not one described in §195.52(a)(4);**
>
> **(3) Confined to company property or pipeline right-of-way; and**
>
> **(4) Cleaned up promptly;**

(c) Death of any person;

(d) Personal injury necessitating hospitalization;

(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

195.52 Immediate notice of certain accidents.

(a) Notice requirements. At the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in §195.50, the operator of the system must give notice, in accordance with paragraph (b) of this section, of any failure that:

> **(1) Caused a death or a personal injury requiring hospitalization;**
>
> **(2) Resulted in either a fire or explosion not intentionally set by the operator;**
>
> **(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;**

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

(b) Information required. Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202–267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Name, address and identification number of the operator.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) Initial estimate of amount of product released in accordance with paragraph (c) of this section.

(7) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

(c) Calculation. A pipeline operator must have a written procedure to calculate and provide a reasonable initial estimate of the amount of released product.

(d) New information. An operator must provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response phase of a reported event at the earliest practicable moment after such additional information becomes known.

§ 195.54 Accident reports.

(a) Each operator that experiences an accident that is required to be reported under §195.50 must, as soon as practicable, but not later than 30 days after discovery of the accident, file an accident report on DOT Form 7000–1, or a facsimile.

(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000–1, it shall file a supplemental report within 30 days.

Further information regarding when reports are identified as “Final” will be covered below under PART A – Key Report Information.

ONLINE REPORTING REQUIREMENTS

Accident Reports must be submitted online unless an alternate method is approved (see Alternate Reporting Methods below).

The following two separate PIN/Password requirements must be fulfilled prior to submitting data online:

1. You must have a PHMSA-provided Operator Identification Number (OPID) and Personal Identification Number (PIN). If you do not have one, complete and submit the form located on the PHMSA-Office of Pipeline Safety Online Data Entry and Operator Registration System New Operator Registration web site at http://opsweb.phmsa.dot.gov to obtain one.

2. You must ALSO have a Username and Password obtained by registering through the PHMSA Portal. If you have a PHMSA OPID and PIN, you may obtain a Username and Password through the PHMSA Portal. If you do not have a Username and Password for the PHMSA Portal, go to https://portal.phmsa.dot.gov/pipeline and click on *Create Account* and complete the form as required.

Important: Each operator without an OPID is to plan accordingly and allow for several weeks prior to the due date of the Report to obtain their OPID from PHMSA.

REPORTING METHODS

Accident Reports must be submitted online unless an alternate method is approved (see Alternate Reporting Methods below). Use the following procedure for online reporting:

1. Navigate to the **Online Data Entry System (ODES 2.0)** at the following URL http://pipelineonlinereporting.phmsa.dot.gov/.

2. Enter Operator Identification Number (OPID) and PIN. *Note: The operator name that appears is assigned to the OPID and PIN, and is automatically populated by our database and cannot be changed by the operator at the time of filing.*

3. Under "**Create Reports**" on the left side of the screen, select "Hazardous Liquid Accident Report" and proceed with entering your data. *Note: Data fields marked with a single asterisk are considered required fields that must be completed before the system will accept your initial submission.*

4. Click "**Submit**" when finished with your data entry to have your report uploaded to PHMSA's database as an official submission of an Accident Report; or click "**Save**" which doesn't submit the report to PHMSA but stores it in a draft status to allow you to come back to complete your data entry and report submission at a later time. *Note: The "Save" feature will allow you to start a report and save a draft of it which you can print out and/or save as a PDF to email to colleagues in order to*

gather additional information and then come back to accurately complete your data entry before submitting it to PHMSA.

5. Once you click "**Submit**", the system will return you to the initial view of the screen that lists your [Saved Incident/Accident Reports] in the top portion of the screen and your [Submitted Incident/Accident Reports] in the bottom portion of the screen. *Note: To confirm that your report was successfully submitted to PHMSA, look for it in the bottom portion of the screen where you can also view a PDF of what you submitted.*

Supplemental Report Filing – Follow Steps 1 and 2 above, and then select a previously submitted report from the [Submitted Incident/Accident Reports] list in the bottom portion of the screen by double clicking on the desired report. The report will default to a "Read Only" mode that is pre-populated with the data you entered previously. To create a Supplemental Report, click on "Create Supplemental" found in the upper right corner of the screen. At this point, you can amend your data and make an official submission of the report to PHMSA as either a Supplemental Report or as a Supplemental Report *plus* Final Report (see "Specific Instructions, PART A, Report Type"), or you can use the "**Save**" feature to create a draft of your Supplemental Report to be submitted at some future date. Reports that were saved will appear in the [Saved Incident/Accident Reports] list in the top portion of the screen and reports that were submitted will appear in the [Submitted Incident/Accident Reports] list in the bottom portion of the screen.

If you submit your report online, DO NOT MAIL OR FAX a hardcopy of the completed report to DOT as this may result in duplicate entries.

Alternate Reporting Methods

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternate reporting method. Operators must follow the requirements in §195.58(d) to request an alternate reporting method and must comply with any conditions imposed as part of PHMSA's approval of an alternate reporting method.

RETRACTING A 30-DAY WRITTEN REPORT

An operator who reports an accident in accordance with **§**195.54 (oftentimes referred to as a 30-day written report) and upon subsequent investigation determines that the event did not meet the criteria in **§**195.50 may request that the report be retracted. Requests to retract a 30-day written report are to be emailed to InformationResourcesManager@dot.gov. Requests are to include the following information:

a. The Report ID (the unique 8-digit identifier assigned by PHMSA)
b. Operator name
c. PHMSA-issued OPID number

d. The number assigned by the National Response Center (NRC) when an immediate notice was made in accordance with §191.5. If Supplemental Reports were made to the NRC for the event, list all NRC report numbers associated with the event.
e. Date of the event
f. Location of the event
g. A brief statement as to why the report should be retracted.

Note: PHMSA no longer requests that operators rescind erroneously reported "Immediate Notices" filed with the NRC in accordance with **§**195.52 (oftentimes referred to as "Telephonic Reports").

SPECIAL INSTRUCTIONS

Certain data fields must be completed before an Original Report will be accepted. The data fields that must be completed for an Original Report to be accepted are indicated on the online form. Your Original Report will not be able to be submitted online until the required information has been provided, although your partially completed form can be saved online so that you can return at a later time to provide the missing information.

1. An entry should be made in each applicable space or check box, unless otherwise directed by the section instructions.

2. If the data is unavailable, enter "Unknown" for text fields and leave numeric fields and fields using check boxes or "radio" buttons blank.

3. Estimate data only if necessary. Provide an estimate in lieu of answering a question with "Unknown" or leaving the field blank. Estimates should be based on best-available information and reasonable effort.

4. For unknown or estimated data entries, the operator should file a Supplemental Report when additional information becomes available.

5. If the question is not applicable, please enter "N/A" for text fields and leave numeric fields and fields using check boxes or "radio" buttons blank. Do not enter zero unless this is the actual value being submitted for the data in question.

6. For questions requiring numeric answers, all preceding and/or unused data fields should be filled in using zeroes. When decimal points or commas are required and not already shown in the data field, **the decimal point or comma should be placed in a separate block** in the data field.

   Examples:

(Part C, item 3.a,) Nominal diameter of pipe (in):	/0/0/2/4/	(24 inches)
	/3/./5/	(3.5 inches)
(Part C, item 3.b), Wall thickness (in)	/0/./3/1/2/	(0.312 inches)
(Part C, item 3.c), SMYS	/0/5/2/,/0/0/0/	(52,000 psi)

7. If **OTHER** is checked for any answer to a question, include an explanation or description on the line provided, making it clear why "Other" was the necessary selection.

8. Pay close attention to each question for the phrase:
   a. ***(select all that apply)***
   b. ***(select only one)***

   If the phrase does not exist for a given question, then "select only one" should apply. "Select only one" means that you should select the single, primary, or most applicable answer. DO NOT SELECT MORE ANSWERS THAN REQUESTED. "Select all that apply" requires that all applicable answers (one or more than one) be selected.

9. **Date format** = mm/dd/yy or for year = /yyyy/

10. **Time format:** All times are reported as a 24-hour clock:

    Time format Examples:

    a. (0000) = midnight = /0/0/0/0/
    b. (0800) = 8:00 a.m. = /0/8/0/0/
    c. (1200) = Noon = /1/2/0/0/
    d. (1715) = 5:15 p.m. = /1/7/1/5/
    e. (2200) = 10:00 p.m. = /2/2/0/0/

    Local time always refers to time at the site of the accident. Note that time zones at the accident site may be different than the time zone for the person discovering or reporting the event. For example, if a release occurs at an gas transmission facility in Denver, Colorado at 2:00 pm MST, but an individual located in Houston is filing the report after having been notified at 3:00 pm CST, the time of the accident is to be reported as 1400 hours based on the time in Denver, which is the physical site of the accident.

SPECIFIC INSTRUCTIONS

PART A – GENERAL REPORT INFORMATION

Report Type: ***(select all that apply)***

Select the appropriate report box or boxes to indicate the type of report being filed. Depending on the descriptions below, the following combinations of boxes - and only one of these combinations - may be selected:

- Original Report only
- Original Report *plus* Final Report
- Supplemental Report only
- Supplemental Report *plus* Final Report

☐ **Original Report**

Select this type of report if this is the FIRST report filed for this accident, and not enough information is available at this time to conclude that this is also a Final Report where no further information will be forthcoming. Select Original Report in cases where further information may be forthcoming, such as when final property damage numbers or apparent failure cause is not immediately available).

☐ **Original Report** *plus* ☐ **Final Report**

Select **both** Original Report and Final Report if ALL of the information requested is known and can be provided at the time the initial report is filed, including final property damage costs and apparent failure cause information. Selecting both these types of reports will indicate that further information is not expected to be forthcoming through a Supplemental Report. If, however, for some reason new, updated, and/or corrected information becomes available unexpectedly, the operator is to still file a Supplemental Report indicating such and explaining the circumstances in PART H – Narrative Description of the Accident.

☐ **Supplemental Report**

Select this type of report only if you have already filed an Original Report AND you are now providing new, updated, and/or corrected information. Multiple Supplemental Reports are to be submitted, as necessary, in order to provide new, updated, and/or corrected information ***when it becomes available*** and, per §191.15(c), each Supplemental Report containing new, updated, and/or corrected information is to be filed as soon as practicable. Submission of new, updated, and/or corrected information is NOT to be delayed in order to accumulate “enough” to “warrant” a Supplemental Report, or to complete a Final Report.

Supplemental Reports must be filed as soon as practicable following the Operator's awareness of new, updated, and/or corrected information. Failure to comply with these requirements can result in enforcement actions, including the assessment of civil penalties not to exceed $100,000 for each violation for each day that such violation persists up to a maximum of $1,000,000.

In cases where an accident results in long-term remediation, an operator may cease filing Supplemental Reports in the following situations and, instead, file a Final Report even when additional remediation costs and recovery of released commodity are still occurring:

1. When the accident response consists only of long-term remediation and/or monitoring which is being conducted under the auspices of an authorized governmental agency or entity.
2. When the estimated final costs and volume of commodity recovered can be predicted with a reasonable degree of certainty.
3. When the volume of commodity recovered over time is consistently decreasing to the point where an estimated total volume of commodity recovered can be predicted with a reasonable degree of accuracy.
4. When the operator can justify (and explain in the Part H – Narrative) that the continuation of Supplemental Report filings in the future will not provide any essential information which will be critically different than that contained in a Final Report filed currently.

In any of these cases, though, if the reported total volume of commodity released or other previously reported data other than "Estimated cost of Operator's environmental remediation" or "Estimated volume of commodity recovered" is found to be inaccurate, a Supplemental Report is still required.

In those cases in which investigations are ongoing, operators should file a Supplemental Report within one year even in those instances where no new, updated, and/or corrected information has been obtained, indicating such in PART H – Narrative Description of Accident.

For Supplemental Reports filed online, all data previously submitted will automatically populate in the form. Page through the form to make edits and additions where needed.

☐ **Supplemental Report** *plus* ☐ **Final Report**

If an Original Report has already been filed AND new, updated, and/or corrected information is now being submitted via a Supplemental Report, AND the operator is reasonably certain that no further information will be forthcoming, then Final Report is to also be selected along with Supplemental Report. (See also the requirements stated above under "Supplemental Report".)

Important: If an operator files one of the two types of Final Reports (either Original *plus* Final or Supplemental *plus* Final) and then subsequently finds that new, updated, and/or corrected information needs to be provided, the operator is to submit another Supplemental Report, selecting the appropriate report types (Supplemental or Supplemental *plus* Final) for the newly submitted report and explaining the circumstances in PART H – Narrative Description of the Accident.

Required Fields for Small Releases:

If the release is at least 5 gallons but is less than 5 barrels with no additional consequences (see below), complete only the fields indicated by light-grey shading. If the spill is to water as described in §195.52(a)(4) or is otherwise reportable under §195.50, then the entire Form PHMSA F 7000-1 must be completed.

The entire form must be completed for any release that:

- Involves death or personal injury requiring hospitalization; or
- Involves fire or explosion; or
- Is 5 barrels or more; or
- Has property damage greater than $50,000; or
- Results in pollution of a body of water; or
- In the judgment of the operator was significant even though it did not meet these criteria.

In Part A, answer Questions 1 thru 18 by providing the requested information or by making the appropriate selection.

1. Operator's OPS -Issued Operator Identification Number (OPID)

The Pipeline and Hazardous Materials Safety Administration (PHMSA) assigns the Operator Identification Number (OPID). Most OPIDs are 5 digits. Older OPIDs may contain fewer digits. If your OPID contains fewer than 5 digits, insert leading zeros to fill all blanks. Contact PHMSA's Information Resources Manager at 202-366-8075 if you need assistance with an OPID. Business hours are 8:30 AM to 5:00 PM Eastern Standard Time.

2. Name of Operator

This is the company name used when registering for an OPID and PIN in PHMSA's Online Data Entry System. For online entries, the Name of Operator will be automatically filled in based on the OPID entered in Question 1. If the name that appears does not coincide with the OPID entered, contact PHMSA's Information Resources Manager at 202-366-8075.

3. Address of Operator

Enter the address of the operator's business office to which any correspondence related to the accident report should be sent.

4. Local time (24-hour clock) and date of the Accident

Enter the date of the accident and the local time the accident occurred.

> See "Special Instructions", numbers 9 and 10 for examples of **Date format** and **Time format** expressed as a 24-hour clock.

5. Location of Accident

The latitude and longitude of the accident are to be reported as Decimal Degrees with a minimum of 5 decimal places (e.g. Lat: 38.89664 Long: -77.04327), using the NAD83 or WGS84 datums.

If you have coordinates in degrees/minutes or degrees/minutes/seconds use the formula below to convert to decimal degrees:

> degrees + (minutes/60) + (seconds/3600) = decimal degrees
> e.g. 38° 53' 47.904" = 38 + (53/60) + (47.904/3600) = 38.89664°

All locations in the United States will have a negative longitude coordinate**, which has already been included on the data entry form so that operators <u>do not</u> have to enter the negative sign**.

If you cannot locate the accident with a GPS or some other means, there are online tools that may assist you at http://www.getlatlon.com/ or http://viewer.nationalmap.gov/viewer/. Any questions regarding the required format, conversion, or how to use the tools noted above can be directed to Amy Nelson (202-493-0591 or amy.nelson@dot.gov).

6. National Response Center (NRC) Report Number

Accidents meeting the criteria outlined in §195.52 are to be reported directly to the **24-hour National Response Center (NRC) at 1-800-424-8802** at the earliest practicable moment (generally within 2 hours). The NRC assigns numbers to each call. The number assigned to that Immediate Notice (sometimes referred to as the "Telephonic Report") is to be entered in Question 6.

7. Local time (24-hr clock) and date of initial telephonic report to the National Response Center

Enter the time and date of the Immediate Notice of the accident to the NRC. The time is to be shown by 24-hour clock notation, and is to reflect the time in the time zone where the accident was physically located. (See "Special Instructions", numbers 9 and 10.)

8. Commodity Released

Select only one primary description of the commodity and then, where applicable, the secondary description of the commodity, based on the predominant volume released. Only releases of transported commodities are reportable.

☐ **Crude Oil**

☐ **Refined and/or Petroleum Product (non-HVL) which is a Liquid at Ambient Conditions**

Refined and/or Petroleum Product includes gasoline, diesel, jet fuel, kerosene, fuel oils, or other refined or petroleum products which are a liquid at ambient conditions. They are flammable, toxic, or corrosive products obtained from distilling or processing of crude oil, unfinished oils, natural gas liquids, blend stocks, and other miscellaneous hydrocarbon compounds. For a non-HVL petrochemical feedstock, such as propylene, report as "other" and specify the name of the commodity (e.g., "propylene") in the space provided.

☐ **HVL or Other Flammable or Toxic Fluid which is a Gas at Ambient Conditions**

Highly Volatile Liquids (HVLs) are hazardous liquids or liquid mixtures which will form a vapor cloud when released to the atmosphere and have a vapor pressure exceeding 276 kPa at 37.8 C.

Other Flammable or Toxic Fluids are those defined under 49 CFR 173.120 Class 3—Definitions

Other flammable or toxic fluids which fall under this category include gases at ambient conditions, such as anhydrous ammonia (NH_3) and propane. For a petrochemical feedstock, such as ethane or ethylene, which is also classified as a highly volatile liquid, report as "Other HVL" and specify the appropriate name (e.g., "ethane" or "ethylene") in the space provided.

☐ **CO_2 (Carbon Dioxide)**

☐ **Biofuel/Alternate Fuel (including ethanol blends)**

Fuel Grade Ethanol is denatured ethanol before it has been mixed with a petroleum product or other hydrocarbon; sometimes also referred to as neat ethanol.

Ethanol Blend is ethanol plus a petroleum product such as gasoline. Such mixtures may be referred to as E10 or E85, for example, representing a 10% or 85% blend respectively. In the space provided, specify the percentage of ethanol in the mixture. Blends greater than 95% ethanol should be reported as Fuel Grade Ethanol.

Biodiesel is a diesel liquid distilled from biological feedstocks vs. crude oil. Biodiesel is typically shipped as a blend mixed with a petroleum product. Report the percentage biodiesel in the blend as shown. For pure biodiesel, report 100.

General Information for Questions 9, 10, and 11:

Estimate volumes in barrels. Barrel means a unit of measurement equal to 42 U.S. standard gallons. If less than 1 barrel, report to 1 decimal place using the conversion table below. De minimus volumes, including but not limited to those which sometimes result in some form of ignition, are to be reported as 0.1 barrels.

If estimated volume is	**Report**	If estimated volume is	**Report**
<5 gallons	**0.1** barrels	24-27 gallons	**0.6** barrels
5-10 gallons	**0.2** barrels	28-31 gallons	**0.7** barrels
11-14 gallons	**0.3** barrels	32-35 gallons	**0.8** barrels
15-18 gallons	**0.4** barrels	36-39 gallons	**0.9** barrels
19-23 gallons	**0.5** barrels	40-42 gallons	**1.0** barrels

General Information for Questions 9 and 10:

Important Note: Volumes consumed by fire and/or explosion are to be included in the estimated volumes reported.

9. Estimated volume of commodity released unintentionally

An estimate of the volume released may be based on a variety and/or combination of inputs, including:

- calculations made by hydraulic engineers
- volume added to the pipeline segment to repack the line when the line is placed back in service
- measured volume of free phase commodity recovered, with allowances for commodity that is not recovered.
- volume calculated to be absorbed by soil or water
- volume calculated to have been lost to evaporation (e.g., for gasoline spills)

Estimate the amount of commodity that was released from the beginning of the accident until such time as the commodity is no longer being released from the system.

10. Estimated volume of intentional and/or controlled release/blowdown

Estimate the amount of commodity that was released during any intentional release or controlled blowdown conducted as part of responding to or recovering from the accident. Intentional and controlled blowdown implies a level of control of the site and situation by the operator such that the area and the public are protected during the controlled release.

11. Estimated volume of commodity recovered

Recovered means the commodity is no longer in the environment. The commodity could have been removed by: absorbent pads or similar mechanisms; transferring to temporary storage such as a vacuum truck, a frac tank, or similar vessel; soil removal; bio-remediation; or other similar means of removal or recovery. The volume can be estimated based on a variety or combination of the measurement of free phase commodity recovered, the amount calculated to be absorbed by soil or water that was removed from the environment, measurement of oil extracted from absorbent pads, etc.

12. Were there fatalities?

If a person dies at the time of the accident or within 30 days of the initial accident date due to injuries sustained as a result of the accident, report as a fatality. If a person dies subsequent to an injury more than 30 days past the accident date, report as an injury. (Note: This aligns with the Department of Transportation's general guidelines for all jurisdictional transportation modes for reporting deaths and injuries.)

Contractor employees working for the operator are individuals hired to work for or on behalf of the operator of the pipeline. These individuals are not to be reported as "Operator employees".

Non-Operator emergency responders are individuals responding to render professional aid at the accident scene including on-duty and volunteer fire fighters, rescue workers, EMTs, police officers, etc. "Good Samaritans" that stop to assist should be reported as "General public."

Workers Working on the Right of Way, but NOT Associated with this Operator means people authorized to work in or near the right-of-way, but not hired by or working on behalf of the operator of the pipeline. This includes all work conducted within the right-of-way including work associated with other underground facilities sharing the right-of-way, building/road construction in or across the right-of-way, or farming. This category most often includes employees of other pipelines or underground facilities operators, or their contractors, working in or near a shared right-of-way. Workers performing work near, but not on, the right-of-way and who are affected should be reported as "General public".

13. Were there injuries requiring inpatient hospitalization?

Injuries requiring inpatient hospitalization are injuries sustained as a result of the accident which require both hospital admission *and* at least one overnight stay.

See Question 12 for additional definitions that apply.

14. Was the pipeline/facility shut down due to the Accident?

Report any shutdowns that occur as a result of the accident, including but not limited to those required for damage assessment, temporary repair, permanent repair, and clean-up.

If No is selected, explain the reason that no shutdown was needed in the space provided.

If Yes is selected, complete questions 14.a and 14.b.

14.a. Local time (24hr clock) and date of shutdown
14.b. Local time pipeline/facility restarted

The time is to be shown by 24-hour clock notation, and is to reflect the time in the time zone where the accident was physically located. (See "Special Instructions", numbers 9 and 10.) Enter the time and date of the shutdown that is associated with the onset or occurrence of the accident in 14.a and the time and date of restart in 14.b. The intent with this data is to capture the total time that the pipeline or facility is shutdown due to the accident. If the pipeline or facility has not been restarted at the time of reporting, select "Still shut down" for Question 14.b and then include the restart time and date in a future Supplemental Report.

15. Did the Commodity Ignite?

Ignite means the released commodity caught fire**.**

16. Did the Commodity Explode?

Explode means the ignition of the released commodity occurred with a sudden and violent release of energy.

17. Number of general public evacuated

The number of people evacuated is to be estimated based on operator knowledge, or police, fire department, or other emergency responder reports. If there was no evacuation involving the general public, report zero (0). If an estimate is not possible for some reason, leave the field blank but include an explanation of why it was not possible to provide a number in PART H – Narrative Description of the Accident.

18. Time sequence (use local time, 24-hour clock)

Enter the time and date the operator became aware of the accident (i.e., when the operator first identified that the accident had occurred, and NOT when the operator determined that the accident met the reporting criteria of §195.50) and the time operator personnel or contract resources (i.e., personnel or equipment) arrived on site. The time is to be shown by 24-hour clock notation, and is to reflect the time in the time zone where the accident was physically located. (See "Special Instructions", numbers 9 and 10.)

PART B – ADDITIONAL LOCATION INFORMATION

1. Was the origin of the accident onshore?

Answer Yes or No as appropriate and complete only the designated questions.

<u>If Onshore</u>

2 – 5. Accident Location

Provide the state, zip code, city, and county/parish in which the accident occurred.

6. Operator-designated Location

This is intended to be the designation that the operator would use to identify the location of the accident on its pipeline system. Enter the appropriate milepost/valve station or survey station number. This designator is intended to allow PHMSA personnel to both return to the physical location of the accident using the operator's own maps and identification systems as well as to identify the "paper" location of the accident when reviewing operator maps and records.

7. Pipeline/Facility Name

Multiple pipeline systems and/or facilities are often operated by a single operator. This information identifies the particular pipeline system or pipeline facility name commonly used by the operator on which the accident occurred, for example, the "West Line 24" Pipeline", or "Gulf Coast Pipeline", or "Wooster Terminal".

8. Segment name/ID

Within a given pipeline system and/or facility, there are typically multiple segment or station identifiers, names, or ID's which are commonly used by the operator. The information reported here helps locate and/or record the more precise accident location, for example, "Segment 4-32", or "MP 4.5 to Wayne County Line", or "Dublin Pump Station", or "Witte Meter Station".

9. Was the Accident on Federal Lands other than Outer Continental Shelf?

Federal Lands other than Outer Continental Shelf means all lands the United States owns, including military reservations, except lands in National Parks and lands held in trust for Native Americans. Accidents at Federal buildings, such as Federal Court Houses, Custom Houses, and other Federal office buildings and warehouses, are NOT to be reported as being on Federal Lands.

10. Location of Accident

Operator-controlled Property would normally apply to an operator's facility, which may or may not have controlled access, but which is often fenced or otherwise marked with discernible boundaries. This "operator-controlled property" does not refer to the pipeline right-of-way, which is a separate choice for this question.

11. Area of Accident (as found)

This refers to the location on the pipeline at which commodity was released, resulting in the accident. It does not refer to adjacent locations in which released commodity may have accumulated or ignited.

Underground means pipe, components, or other facilities installed below the natural ground level, road bed, or below the underwater natural bottom.

Under pavement includes under streets, sidewalks, paved roads, driveways, and parking lots.

Exposed due to Excavation means that a normally buried pipeline had been exposed by any party (operator, operator's contractor, or third party) preparatory to or as a result of excavation. The cause of the release, however, may or may not necessarily be related to excavation damage. This category could include a corrosion leak not previously evidenced by stained vegetation, but found during an ILI dig, or a release caused by a non-excavation vehicle where contact happened to occur while the pipeline was exposed for a repair or examination. Natural forces might also damage a pipeline that happened to be temporarily exposed. In each case, the cause should be appropriately reported in PART G of this form.

Aboveground means pipe, components, or other facilities that are above the natural grade.

Typical aboveground facility piping includes any pipe or components installed aboveground such as those at pump stations, valve sites, and breakout tank farms.

Transition area means the junction of differing material or media between pipes, components, or facilities such as those installed at a belowground-aboveground junction (soil/air interface), another environmental interface, or in close contact to supporting elements such as those at water crossings, pump stations and break out tank farms.

12. Did Accident occur in a crossing?

Use **Bridge Crossing** if the pipeline is suspended above a body of water or roadway, railroad right-of-way, etc., either on a separately designed pipeline bridge or as a part of or connected to a road, railroad, or passenger bridge.

Use **Railroad Crossing** or **Road Crossing**, as appropriate, if the pipeline is buried beneath rail bed or road bed.

Use **Water Crossing** if the pipeline is in the water, beneath the water, in contact with the natural ground of the lake bed, etc., or buried beneath the bed of a lake, reservoir, stream or creek, whether the crossing happens to be flowing water at the time of the accident or not. The name of the body of water should be provided if it is commonly known and understood among the local population. (The purpose of this information is to allow persons familiar with the area in which the accident occurred to identify the location and understand it in its local context. Research to identify names that are not commonly used is not necessary since such names would not fulfill the intended purpose. If a body of water does not have a name that is commonly used and understood in the local area, this field may be left blank).

For **Approximate Water Depth (ft)** of the lake, reservoir, etc., estimate the typical water depth at the location of the accident, ignoring seasonal, weather-related, and other factors which may affect the water depth from time to time.

<u>If Offshore</u>

13. Approximate water depth (ft.), at the point of the Accident

This is be the estimated depth from the surface of the water to the seabed at the point of the accident regardless of whether the pipeline is below/on the bottom, underwater but suspended above the bottom, or above the surface (e.g., on a platform).

14. Origin of the Accident

Area and Tract/Block numbers are to be provided for either State or OCS waters, whichever is applicable.

For Nearest County/Parish, as with the name of an onshore body of water (see Question 12 above), the data collected is intended to allow persons familiar with the area in which the accident occurred to identify the location and understand it in its local context. Accordingly, it is not necessary to take measurements to determine which county/parish is "nearest" in cases where the accident location is approximately equidistant from two (or more). In such cases, the name of one of the nearby counties/parishes is to be provided.

PART C – ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility [Interstate or Intrastate]?

As defined in section 195.2, **Interstate pipeline** means a pipeline or that part of a pipeline that is used in transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

As defined in section 195.2, **Intrastate pipeline** means a pipeline or that part of a pipeline to which Part 195 applies that is not an interstate pipeline.

Operators may refer to Appendix A of Part 195 for further guidance.

3. Item involved in Accident

Pipe (whether pipe body or pipe seam) means the pipe through which the commodity is transported, not including auxiliary piping, tubing or instrumentation.

Nominal diameter of pipe is also called **Nominal pipe size.** It is the diameter in whole number inches (except for pipe less than 4”) used to describe the pipe size; for example, 8-5/8 pipe has a nominal pipe size of 8”. Decimals are unnecessary for this measure (except for pipe less than 4”).

Enter **pipe wall thickness** in inches. Wall thickness is typically less than an inch, and is standard among different pipeline types and manufacturers. Accordingly, use three decimal places to report wall thickness: 0.312, 0.281, etc.

SMYS means specified minimum yield strength and is the yield strength prescribed by the specification under which the material is purchased from the manufacturer.

Pipe Specification is the specification to which the pipe was manufactured, such as API 5L or ASTM A106.

Pipe seam means the longitudinal seam (longitudinal weld) created during manufacture of the joint of pipe.

Pipe Seam Type Abbreviations

SAW means submerged arc weld
ERW means electric-resistance weld
DSAW means double submerged arc weld

Auxiliary piping means piping, usually small in diameter that supports the operation of the mainline or facility piping and does not include tubing. Examples of auxiliary piping include discharge and drain lines, sample lines, etc.

If the accident occurred on an item not provided in this section, select "Other" and specify the item that failed in the space provided.

6. Type of Accident involved *(select only one)*

Mechanical puncture means a puncture of the pipeline, typically by a piece of equipment such as would occur if the pipeline were pierced by directional drilling or a backhoe bucket tooth. Not all excavation-related damage will be a "mechanical puncture." (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and one decimal.)

Leak means a failure resulting in an unintentional release of the transported commodity that is often small in size, usually resulting in a low flow release of low volume, although large volume leaks can and do occur on occasion.

Rupture means a loss of containment that immediately impairs the operation of the pipeline. Pipeline ruptures often result in a higher flow release of larger volume. The terms "circumferential" and "longitudinal" refer to the general direction or orientation of the rupture relative the pipe's axis. They do not exclusively refer to a failure involving a circumferential weld such as a girth weld, or to a failure involving a longitudinal weld such as a pipe seam. (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and one decimal.)

PART D – ADDITIONAL CONSEQUENCE INFORMATION

Per 195.450, High Consequence Area means:

1. A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;
2. A *high population area*, which means an urbanized area as defined and delineated by the Census Bureau that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;
3. An *other populated area*, which means a place as defined and delineated by the Census Bureau that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;
4. An *unusually sensitive area*, as defined in §195.6

*** * * * ***

5.b Estimated amount released in or reaching water

An estimate of the volume released in or reaching water may be based on a variety and/or combination of inputs, including those mentioned above for PART A, Questions 9 and 10.

5.c Name of body of water, if commonly known:

The name of the body of water should be provided if it is commonly known and understood among the local population. (The purpose of this information is to allow persons familiar with the area in which the accident occurred to identify the location and understand it in its local context. Research to identify names that are not commonly used is not necessary since such names would not fulfill the intended purpose. If a body of water does not have a name that is commonly used and understood in the local area, this field should be left blank).

6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?

This question should be answered based on the classification of the involved segment in the operator's integrity management (IM) program at the time of the accident, whether or not consequences to an HCA ensued. It is possible that a release on a pipeline segment that "could affect" an HCA might not actually affect an HCA. It is also possible that releases from segments thought not able to affect an HCA might have such an affect. This could indicate a deficiency in the operator's IM program for identifying segments that can affect HCAs, and all of this information is useful for PHMSA's overall evaluations concerning the efficacy of IM regulation.

7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?

Guidance available from the pipeline industry for its own spill reporting system is pertinent here. Please see **http://committees.api.org/pipeline/ppts/docs/Advisories/2004-1AdvisoryHCAReporting.pdf**

Generally, a spilled commodity will have "reached" an HCA if the spill zone intersects the boundaries of the HCA polygon as mapped by the National Pipeline Mapping System. The HCA maps should be available as a part of each operator's Integrity Management Program as per §195.452.

7.a. HCA Type (**select all that apply**)

Refer to the definitions in §192.450, reproduced above. Leave this question blank if the released commodity did not reach or occur in a High Consequence Area.

8. Estimated Property Damage

All relevant costs available at the time of submission must be included on the initial written Accident Report as well as being updated as needed on Supplemental Reports. This includes (but is not limited to) costs due to property damage to the operator's facilities and to the property of others, commodity lost, facility repair and replacement, and environmental cleanup and damage. Do NOT include costs incurred for facility repair, replacement, or change that are NOT related to the accident and which are typically done solely for convenience. An example of doing work solely for convenience is working on non-leaking facilities unearthed because of the accident. Litigation and other legal expenses related to the accident are not reportable.

Operators are to report costs based on the best estimate available at the time a report is submitted. It is likely that an estimate of final repair costs may not be available when the initial report must be submitted (30 days, per §195.54). The best available estimate of these costs should be included in the initial report. For convenience, this estimate can be revised, if needed, when Supplemental Reports are filed for other reasons, however, when no other changes are forthcoming, Supplemental Reports are to be filed as new cost information becomes available. If Supplemental Reports are not submitted for other reasons, a Supplemental Report is to be filed for the purpose of updating or correcting the estimated cost if these costs differ from those already reported by 20 percent or $20,000, whichever is greater.

Public and Non-operator private property damage estimates generally include physical damage to the property of others, the cost of environmental investigation and remediation of a site not owned or operated by the operator, laboratory costs, third party expenses such as engineers or scientists, and other reasonable costs, excluding litigation and other legal expenses related to the accident.

Cost of commodity lost includes the cost of the commodity not recovered and/or the cost of recovered commodity downgraded to a lower value or re-processed, and is to be based on the volume reported in PART A, Questions 9, 10, and 11.

Operator's property damage estimates generally include physical damage to the property of the operator or owner company such as the estimated installed or replacement value of the damaged pipe, coating, component, materials, or equipment due to the accident, excluding litigation and other legal expenses related to the accident.

When estimating the **Cost of repairs** to company facilities, the standard shall be the cost necessary to safely restore property to its predefined level of service. Property damage estimates include the cost to access, excavate, and repair the pipeline using methods, materials, and labor necessary to re-establish operations at a predetermined level. These costs may include the cost of repair sleeves or clamps, re-routing of piping, or the removal from service of an appurtenance, tank, or pipeline component. When more comprehensive repairs or improvements are justified but not required for continued operation, the cost of such repairs or replacement is not attributable to the accident. Costs associated with improvements to the pipeline or other facilities to mitigate the risk of future failures are not included.

The following examples are provided for clarity and guidance:

> Tank accident - Property damage estimates would include the cost to remove the tank from service, sufficiently clean the tank, repair the tank to a standard operating capability, and then return the tank to service. Costs

associated with improvements to the tank to mitigate the risk of future failures are not included.

Pipeline accident - Property damage estimates include the cost to access, excavate and repair the pipeline using methods, materials, and labor necessary to re-establish operations at a predetermined level. Costs associated with improvements to the pipeline to mitigate the risk of future failures are not included.

Estimated costs of **Operator's emergency response** include emergency response operations necessary to return the accident site to a safe state, actions to minimize the volume of commodity released, conduct reconnaissance, identify the extent of accident impacts, and contain, control, mitigate, recover, and remove the commodity from the environment, to the maximum extent practicable. They include materials, supplies, labor, and benefits. Costs related to stakeholder outreach, media response, etc. are not to be included. The estimated costs of long-term remediation activities should be included in Environmental Remediation estimates.

Environmental remediation includes the estimated cost to remediate a site such as those associated with engineering, scientists, laboratory costs, and the installation, operation, and maintenance of long-term recovery systems, etc.

Other costs are to include any and all costs which are not included above. Operators are to NOT use this category to report any costs which belong in cost categories separately listed above.

Costs are to be reported in only one category and are not to be double-counted. Costs can be split between two or more categories when they overlap more than one reporting category.

PART E – ADDITIONAL OPERATING INFORMATION

4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?

Consider both voluntary and mandated pressure restrictions. A pressure restriction is to be considered mandated by PHMSA or a state regulator if it was directed by an order or other formal correspondence. Pressure reductions imposed by the operator as a result of regulatory requirements, e.g., a pressure reduction taken because an anomaly identified during an IM assessment could not be repaired within the required schedule (**§**195.452(h)(3)), is not to be considered mandated by PHMSA.

5.a. Type of upstream valve used to initially isolate release source

Identify the type of valve used to initially isolate the release on the upstream side. In general, this will be the first upstream valve selected by the operator to minimize the release volume but may not be the closest to the accident site or the one that was eventually used for the final isolation of the release site for repair.

5.b. Type of downstream valve used to initially isolate release source

Identify the type of valve used to initially isolate the release on the downstream side. In general, this will be the first downstream valve selected by the operator to minimize the release volume but may not be the closest to the accident site or the one that was eventually used for the final isolation of the release site for repair.

5.c. Length of segment isolated between valves (ft)

Identify the length in feet between the valves identified in Questions 5.a and 5.b that were initially used to isolate the spill area.

5.f. Function of pipeline system

Gathering means a crude oil pipeline 8-5/8 inches or less nominal outside diameter that transports petroleum from a production facility.

Trunkline/Transmission means all other pipeline assets not meeting the gathering definition.

SMYS means specified minimum yield strength and is the yield strength prescribed by the specification under which the material is purchased from the manufacturer.

6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?

This does not mean a system designed or used exclusively for leak detection.

6.a. Was it operating at the time of the Accident?

Was the SCADA system in operation at the time of the accident?

6.b. Was it fully functional at the time of the Accident?

Was the SCADA system capable of performing all of its functions, whether or not it was actually in operation at the time of the accident? If No, describe functions that were not operational in PART H – Narrative Description of the Accident.

6.c and d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection (or confirmation) of the Accident?

Select Yes if SCADA-based information was used to confirm the accident even if the initial report or identification may have come from other sources. Use of SCADA data for subsequent estimation of amount of commodity lost, etc. is not considered use to confirm the accident.

Select No if SCADA-based information was not used to assist with identification of the accident.

7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?

This means a system designed and used exclusively for leak detection.

Follow instructions for Question 6 above.

8. How was the Accident initially identified for the Operator? ***(select only one)***

Controller per the definition in API RP 1168 means a qualified individual whose function within a shift is to remotely monitor and/or control the operations of entire or multiple sections of pipeline systems via a SCADA system from a pipeline control room, and who has operational authority and accountability for the daily remote operational functions of pipeline systems.

Local Operating Personnel including contractors means employees or contractors working on behalf of the operator outside the control room.

9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?

Select only one of the choices to indicate whether an investigation was/is being conducted (Yes) or was not conducted (No). If an investigation has been completed, select all the factors that apply in describing the results of the investigation.

Cause means an action or lack of action that directly led to or resulted in the pipeline accident.

Contributing factor means an action or lack of action that when added to the existing pipeline circumstances heightened the likelihood of the release or added to the impact of the release.

Controller Error means that the controller failed to identify a circumstance indicative of a release event, such as an abnormal operating condition, alarm, pressure drop, change in flow rate, or other similar event.

Incorrect Controller action means that the controller errantly operated the means for controlling an event. Examples include opening or closing the wrong valve, or hitting the wrong switch or button.

PART F – DRUG & ALCOHOL TESTING INFORMATION

Requirements for post-accident drug and alcohol tests are in 49 CFR §199.105 and §195.225 respectively. If the accident circumstances were such that tests were not required by these regulations, and if no tests were conducted, select No. If tests were administered, select Yes and report separately the number of operator employees and number of contractors working for the operator who were tested and the number of each that failed such tests.

PART G – APPARENT CAUSE

PART G – Apparent Cause

Select the one, single sub-cause listed under sections G1 thru G8 that best describes the apparent cause of the Accident. These sub-causes are contained in the shaded column on the left under each main cause category. Answer the corresponding questions that accompany your selected sub-cause, and describe any secondary, contributing, or root causes of the Accident in PART H – Narrative Description of the Accident.

G1 – Corrosion Failure

Corrosion includes a release or failure caused by galvanic, atmospheric, stray current, microbiological, or other corrosive action. A corrosion release or failure is not limited to a hole in the pipe or other piece of equipment. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is to be classified as Corrosion. (Note: If the bonnet, packing, or other gasket has deteriorated to failure, whether before or after the end of its expected life, but not due to corrosive action, it is to be classified under G6 - Equipment Failure.)

External Corrosion

4.a. Under cathodic protection means cathodic protection in accordance with §195.563 or §195.573(b). Recognizing that older pipelines may have had cathodic protection added over a number of years, provide an estimate if the exact year cathodic protection started is unknown.

Internal Corrosion

9. Location of corrosion

A **low point in pipe** includes portions of the pipe contour in which water might settle out. This includes, but is not limited to, the low point of vertical bends at a crossing of a foreign line or road/railroad, etc., an elbow, a drop out or low point drain.

10. Was the commodity treated with corrosion inhibitors or biocides?

Select Yes if corrosion inhibitors or biocides were included in the commodities transported.

12. Were cleaning/dewatering pigs (or other operations) routinely utilized?

13. Were corrosion coupons routinely utilized?

For purposes of these Questions 12 and 13, "routinely" refers to an action that is performed on more than a sporadic or one-time basis as part of a regular program with the intent to ensure that water build-up and/or settling and internal corrosion do not occur.

Either External or Internal Corrosion

14. List the year of the most recent inspections

Complete this question only when any corrosion failure sub-cause is selected AND the item involved in the accident (as reported in PART C, Question 3) is "Tank/Vessel". Do not complete if the item involved is Pipe, Weld, or any other item.

15.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run

Magnetic Flux Leakage Tool is an in-line inspection tool using an imposed magnetic flux to detect instances of pipe wall loss from corrosion. Includes low- and high-resolution MFL tools. Does not include transverse flux MFL tools, which are a separate choice in this question.

Ultrasonic refers to an in-line inspection tool that uses ultrasonic technology to measure wall thickness and detect instances of wall loss.

Transverse Field/Triaxial tools are specialized magnetic flux leakage tools that use a flux oriented to improve ability to detect crack anomalies.

Combination Tool refers to any in-line inspection tool that uses a combination of these inspection technologies in a single tool.

16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?

Information from the initial post-construction hydrostatic test is not to be reported.

17. Has one or more Direct Assessment been conducted on this segment?

This refers to direct assessment as defined in §195.553. Instances in which one or more indirect monitoring tools (e.g., close interval survey, DCVG) have been used that might be used as part of direct assessment but which were not used as part of the direct assessment process defined in §195.553 do NOT constitute a Direct Assessment for purposes of this question.

G2 – Natural Force Damage

Natural Force Damage includes a release or failure resulting from earth movement, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslide, scouring, temperature, frost heave, frozen components, high winds, or similar natural causes.

Earth Movement, NOT due to Heavy Rains/Floods refers to accidents caused by land shifts such as earthquakes, subsidence, or landslides, but not mudslides which are presumed to be initiated by heavy rains or floods.

Heavy Rains/Floods refer to all water-related natural force causes. While mudslides involve earth movement, report them here since typically they are an effect of heavy rains or floods.

Lightning includes both damage and/or fire caused by a direct lighting strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by lightning that results in damage to a pipeline system asset which results in an accident. (See also the discussion of "secondary ignition" under the *General Instructions*.)

Temperature includes weather-related temperature and thermal stress effects, either heat or cold, where temperature was the initiating cause.

> **Thermal stress** refers to mechanical stress induced in a pipe or component when some or all of its parts are not free to expand or contract in response to changes in temperature.
>
> **Frozen components** would include accidents where components are inoperable because of freezing and those due to cracking of a piece of equipment due to expansion of water during a freeze cycle.

High Winds includes damage caused by wind-induced forces. Select this category if the damage is due to the force of the wind itself. Damage caused by impact from objects blown by wind would be reported under G4 - Other Outside Force Damage.

Other Natural Force Damage. Select this sub-cause for types of Natural Force Damage not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Accident.

Answer Questions 6 and 6.a if the accident occurred in conjunction with an extreme weather event such as a hurricane, tropical storm, or tornado. If an extreme weather event related to something other than a hurricane, tropical storm, or tornado was involved, indicate Other and describe the event in the space provided.

G3 – Excavation Damage

Excavation Damage includes a release or failure resulting directly from excavation damage by operator's personnel (oftentimes referred to as “first party” excavation damage) or by the operator’s contractor (oftentimes referred to as “second party” excavation damage) or by people or contractors not associated with the operator (oftentimes referred to as “third party” excavation damage). Also, this section includes a release or failure determined to have resulted from previous damage due to excavation activity. For damage from outside forces OTHER than excavation which results in a release, use G2 - Natural Force Damage or G4 - Other Outside Force, as appropriate. Also, for a strike, physical contact, or other damage to a pipeline or facility that apparently was NOT related to excavation and that results in a delayed or eventual release, report the accident under G4 as “Previous Mechanical Damage NOT related to Excavation.”

Excavation Damage by Operator (First Party) refers to accidents caused as a result of excavation by a direct employee of the operator.

Excavation Damage by Operator’s Contractor (Second Party) refers to accidents caused as a result of excavation by the operator’s contractor or agent or other party working for the operator.

Excavation Damage by Third Party refers to accidents caused by excavation damage resulting from actions by personnel or other third parties not working for or acting on behalf of the operator or its agent.

Previous Damage due to Excavation Activity refers to accidents that were apparently caused by prior excavation activity and that then resulted in a delayed or eventual release. Indications of prior excavation activity might come from the condition of the pipe when it is examined, or from records of excavation at the site, or through metallurgical analysis or other inspection and/or testing methods. Dents and gouges in the 10:00-to-2:00 o’clock positions on the pipe, for instance, may indicate an earlier strike, as might marks from the bucket or tracks of an earth moving machine or similar pieces of equipment.

1.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run

Magnetic Flux Leakage Tool is an in-line inspection tool using an imposed magnetic flux to detect instances of pipe wall loss from corrosion. Includes low- and high-resolution MFL tools. Does not include transverse flux MFL tools, which are a separate choice in this question.

Ultrasonic refers to an in-line inspection tool that uses ultrasonic technology to measure wall thickness and detect instances of wall loss.

Transverse Field/Triaxial tools are specialized magnetic flux leakage tools that use a flux oriented to improve ability to detect crack anomalies.

Combination Tool refers to any in-line inspection tool that uses a combination of these inspection technologies in a single tool.

3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?

Information from the initial post-construction hydrostatic test is not to be reported.

4. Has one or more Direct Assessment been conducted on this segment?

This refers to direct assessment as defined in §195.553. Instances in which one or more indirect monitoring tools (e.g., close interval survey, DCVG) have been used that might be used as part of direct assessment but which were not used as part of the direct assessment process defined in §195.553 do not constitute a Direct Assessment for purposes of this question.

7. – 17. Complete these questions for any excavation damage sub-cause. Instructions for answering these questions can be found at CGA's web site, https://www.damagereporting.org/dr/control/userGuide.do.

G4 – Other Outside Force Damage

Other Outside Force Damage includes, but are not limited to, a release or failure resulting from non-excavation-related outside forces, such as nearby industrial, man-made, or other fire or explosion; damage by vehicles or other equipment; failures due to mechanical damage; and, intentional damage including vandalism and terrorism.

Nearby Industrial, Man-made or other Fire/Explosion as Primary Cause of Accident applies to situations where the fire occurred before - and *caused* - the release**.** (See also the discussion of "secondary ignition" under the *General Instructions*.) Examples of such an accident would be an explosion or fire at a neighboring facility or installation (chemical plant, tank farm, other industrial facility) or structure, debris, or brush/trees that results in a release at the operator's pipeline or facility. This includes forest, brush, or ground fires that are caused by human activity. If the fire, however, is known to have been started as a result of a lightning strike, the accident's cause is to be classified under G2 - Natural Force Damage. Arson events directed at harming the pipeline or the operator should be reported as G4 - Intentional Damage (see below). This sub-cause is NOT to be used if the release occurred first and then the gas released from the pipeline system or facility ignited.

Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation. An example of this sub-cause would be a stopple tee that releases commodity when damaged by a pickup truck maneuvering near the pipeline. Other motorized vehicles or equipment include tractors, backhoes, bulldozers and other tracked vehicles, and heavy equipment that can move. Include under this sub-cause accidents caused by vehicles operated by the pipeline operator, the pipeline operator's contractor, or a third party, and

specify the vehicle/equipment operator's affiliation from one of these three groups. Pipeline accidents resulting from vehicular traffic loading or other contact should also be reported in this category. If the activity that caused the release involved digging, drilling, boring, grading, cultivation or similar activities, report under G3 - Excavation Damage.

Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring. This sub-cause includes impacts by maritime equipment or vessels (including their anchors or anchor chains or other attached equipment) that have lost their moorings and are carried into the pipeline facility by the current. This sub-cause also includes maritime equipment or vessels set adrift as a result of severe weather events and carried into the pipeline facility by waves, currents, or high winds. In such cases, also indicate the type of severe weather event. Do NOT report in this sub-cause accidents which are caused by the impact of maritime equipment or vessels while they are engaged in their normal or routine activities; such accidents are to be reported as "Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation" under this section G4 (see below) so long as those activities are not excavation activities. If those activities are excavation activities such as dredging or bank stabilization or renewal, the accident is to be reported under G3 - Excavation Damage.

Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation. This sub-cause includes accidents due to shrimping, purseining, oil drilling, or oilfield workover rigs, including anchor strikes, and other routine or normal maritime-related activities UNLESS the movement of the maritime asset was due to a severe weather event (this type of accident should be reported under "Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring" in this section G4); or the accident was caused by excavation activity such as dredging of waterways or bodies of water (this type of accident is to be reported under G3 - Excavation Damage).

Electrical Arcing from Other Equipment or Facility such as a pole transformer or adjacent facility's electrical equipment.

Previous Mechanical Damage NOT Related to Excavation. This sub-cause covers accidents where damage occurred at some time prior to the release that was apparently NOT related to excavation activities, and would include prior outside force damage of an unknown nature, prior natural force damage, prior damage from other outside forces, and any other previous mechanical damage other than that which was apparently related to prior excavation. Accidents resulting from previous damage sustained during construction, installation, or fabrication of the pipe or weld from which the release eventually occurred are to be reported under G5 - Material Failure of Pipe or Weld. (See this sub-cause for typical indications of previous construction, installation, or fabrication damage.) Accidents resulting from previous damage sustained as a result of excavation activities should be reported under G3 – Previous Damage due to Excavation Activity. (See this sub-cause for typical indications of prior excavation activity.)

Intentional Damage

> **Vandalism** means willful or malicious destruction of the operator's pipeline facility or equipment. This category would include arson, pranks, systematic damage inflicted to harass the operator, motor vehicle damage that was inflicted intentionally, and a variety of other intentional acts. (See also the discussion of "secondary ignition" under the *General Instructions*.)
>
> **Terrorism**, per 28 CFR §0.85 General Functions, includes the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives. Operators selecting this item are encouraged to also notify the FBI.
>
> **Theft of commodity or Theft of equipment** means damage by any individual or entity, by any mechanism, specifically to steal, or attempt to steal, the transported commodity or pipeline equipment.
>
> **Other** Describe in the space provided and, if necessary, provide additional explanation in PART H – Narrative Description of the Accident.

Other Outside Force Damage. Select this sub-cause for types of Other Outside Force Damage not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Accident.

G5 – Material Failure of Pipe or Weld

Use this section to report material failures **only if** "Item Involved in accident" (PART C, Question 3) is "**Pipe**" (whether "**Pipe Body**" **or** "**Pipe Seam**") or "**Weld**." Indicate how the sub-cause was determined or if the sub-cause is still being investigated.

This section includes releases in or failures from defects or anomalies within the material of the pipe body or within the pipe seam or other weld due to faulty manufacturing procedures, defects resulting from poor construction, installation, or fabrication practices, and in-service stresses such as vibration, fatigue, and environmental cracking.

Construction-, Installation-, or Fabrication-related includes a release or failure caused by a dent, gouge, excessive stress, or some other defect or anomaly introduced during the process of constructing, installing, or fabricating pipe and pipe welds, including welding or other activities performed at the facility. Included are releases from or failures of wrinkle bends, field welds, and damage sustained in transportation to the construction or fabrication site. Not included are failures due to seam defects, which are to be reported as Original Manufacturing-related (see below).

Original Manufacturing-related (NOT girth weld or other welds formed in the field) includes a release or failure caused by a defect or anomaly introduced during the process of

manufacturing pipe, including seam defects and defects in the pipe body. This option is not appropriate for wrinkle bends, field welds, girth welds, or other joints fabricated in the field. Use this option for failures such as those due to defects of the longitudinal weld or inclusions in the pipe body.

If **Construction, Installation, Fabrication-related** or **Original Manufacturing-related** is selected, then select any contributing factors. Examples of Mechanical Stress include failures related to overburden or loss of support.

G6 – Equipment Failure

This section applies to failures of items **<u>other than</u>** "**Pipe**" ("**Pipe Body**" **or** "**Pipe Seam**") **or** "**Weld**".

Equipment Failure includes a release or failure resulting from: malfunction of control/relief equipment including valves, regulators, or other instrumentation; failures of compressors, or compressor-related equipment; failures of various types of connectors, connections, and appurtenances; failures of the body of equipment, vessel plate, or other material (including those caused by construction-, installation-, or fabrication-related and original manufacturing-related defects or anomalies); and, all other equipment-related failures.

Malfunction of Control/Relief Equipment. Examples of this type of accident cause include: overpressurization resulting from malfunction of a control or alarm device; relief valve malfunction; valves failing to open or close on command; or valves which opened or closed when not commanded to do so. If overpressurization or some other aspect of this accident was caused by incorrect operation, the accident should be reported under G7 - Incorrect Operation.

ESD System Failure means failure of an emergency shutdown system.

Other Equipment Failure. Select this sub-cause for types of Equipment Failure not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Accident.

G7 – Incorrect Operation

Incorrect Operation includes a release or failure resulting from operating, maintenance, repair, or other errors by facility personnel, including, but not limited to improper valve selection or operation, inadvertent overpressurization, or improper selection or installation of equipment.

Other Incorrect Operation. Select this sub-cause for types of Incorrect Operation not included otherwise, and describe in the space provided. If necessary, provide additional explanation in PART H – Narrative Description of the Accident.

G8 – Other Accident Cause

This section is provided for accidents whose cause is currently unknown, or where investigation into the cause has been exhausted and the final judgment as to the cause remains unknown, or where a cause has been determined which does not fit into any of the main cause categories listed in sections G1 thru G7.

If the accident cause is known but doesn't fit into any category in sections G1 thru G7, select **Miscellaneous** and enter a description of the accident cause, continuing with a more thorough explanation in PART H - Narrative Description of the Accident.

If the accident cause is unknown at the time of filing this report, select **Unknown** in this section and specify one reason from the accompanying two choices. Once the operator's investigation into the accident cause is completed, the operator is to file a Supplemental Report as soon as practicable either reporting the apparent cause or stating definitively that the cause remains Unknown, along with any other new, updated, and/or corrected information pertaining to the accident. This Supplemental Report is to include all new, updated, and/or corrected information pertaining to *all* portions of the report form known at this time, and not only that information related to the apparent cause.

Important Note: Whether the investigation is completed or not, or if the cause continues to be unknown, Supplemental Reports are to be filed reflecting new, updated, and/or corrected information ***<u>as and when this information becomes available</u>***. In those cases in which investigations are ongoing for an extended period of time, operators are to file a Supplemental Report within one year of their last report for the accident even in those instances where no new, updated, and/or corrected information has been obtained, with an explanation that the cause remains under investigation in PART H – Narrative Description of Accident. Additionally, final determination of the apparent cause and/or closure of the investigation does NOT preclude the need for the operator's filing of additional Supplemental Reports as and when new, updated, and/or corrected information becomes available.

PART H – NARRATIVE DESCRIPTION OF THE ACCIDENT

Concisely describe the accident, including the facts, circumstances, and conditions that may have contributed directly or indirectly to causing the accident. Include secondary, contributing, or root causes when possible, or any other factors associated with the cause that are deemed pertinent. Use this section to clarify or explain unusual conditions, to provide sketches or drawings, and to explain any estimated data. Operators submitting reports on-line will be afforded the opportunity to attach/upload files (in PDF or JPG format only) containing sketches, drawings, or additional data.

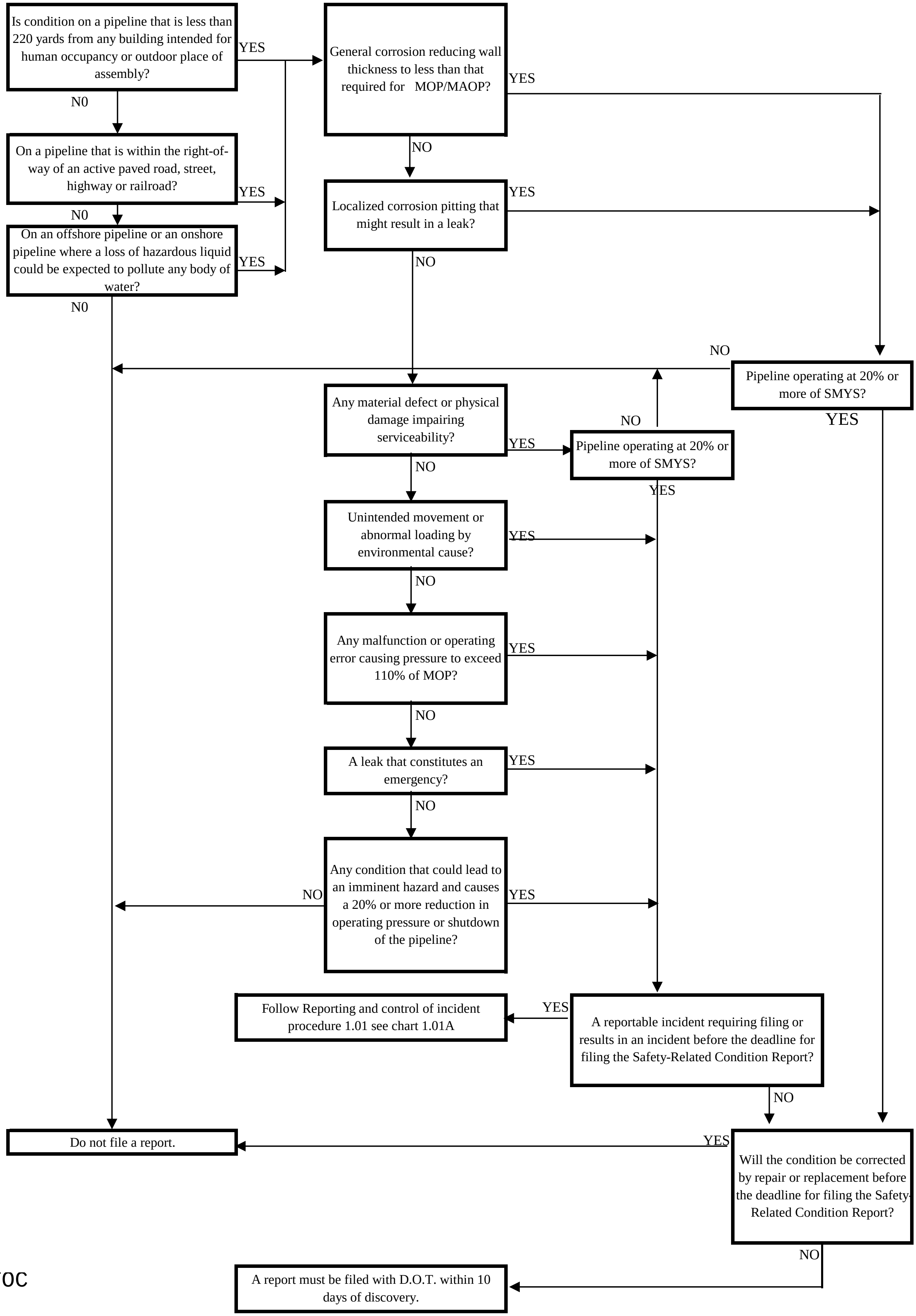
If you selected Miscellaneous in section G8, the narrative is to describe the accident in detail, including all known or suspected causes and possible contributing factors.

PART I – PREPARER AND AUTHORIZED SIGNATURE

The Preparer is the person who compiled the data and prepared the responses to the report and who is to be contacted for more information (preferably the person most knowledgeable about the information in the report or who knows how to contact the person most knowledgeable). Enter the Preparer's e-mail address if the Preparer has one, and the phone and fax numbers used by the Preparer.

An Authorized Signature must be obtained from an officer, manager, or other person whom the operator has designated to review and approve the report. This individual is responsible for assuring the accuracy and completeness of the reported data. In addition to their title, a phone number and email address are to be provided for the individual signing as the Authorized Signature.

REPORTING OF SAFETY RELATED CONDITIONS
CHART 1.02A



TOC

SAFETY RELATED CONDITION REPORT
FORM 1.02B

Company: ______	Operating Location: ______	Date: ______ MO / DAY / YR

Person Submitting Report:	Person Who Determined Condition Exists:
Name: ______	Name: ______
Title: ______	Title: ______
Telephone: ______	Telephone: ______
Date Condition Discovered: ______	Date Condition Determined: ______

Location of Condition:

- ☐ Rural
- ☐ Non-Rural
- ☐ Offshore

Pipeline Name and Number: ______ Class Location:(Gas) ______

Date(s) of Installation of all Affected Pipeline Segments: ______

O.D. ______ Station or Mile Post: ______

Wall Thickness: ______ Grade: ______

Plant Field / Area: ______

State: ______ County/Parish: ______ Sec/Twnship/Rnge: ______

Name of nearest street or road (where applicable) ______

Condition Description:

______

Corrective Action Taken:

______

Signatures:

Person Completing This Form: ______

Supervisor: ______

TOC

ACCIDENT & NEAR MISS INVESTIGATION REPORT

(Any Accident or Near Miss)

Pipeline O&M Form #1.03A

PERSON(S) INVOLVED	
Name:	Employee or contractor:
Address:	Phone number:
Name:	Employee or contractor:
Address:	Phone number:
EMPLOYER INFORMATION (If contractor)	
Employer name:	Phone number:
Address:	
ACCIDENT / NEAR MISS INFORMATION	
Date of occurrence:	
Exact location of accident:	
Description of accident:	
What unsafe action/condition was the root cause of the accident?	
What corrective action has been taken to prevent reoccurrence?	
Person responsible for corrective action:	
REPORT REVIEW	
Person(s) involved signature(s):	Date:
Operations Supervisor signature:	Date:
Plant Manager signature:	Date:

Pipeline Failure Investigation Report

Pipeline System: ______________________ **Operator:** ______________________

Location: ______________________ **Date of Occurrence:** ______________________

Medium Released: ______________________ **Quantity:** ______________________

OPS Arrival Time & Date: ______________________ **Total Damages $:** ______________________

Investigation Responsibility: ☐ State ☐ OPS ☐ NTSB Other ______________________

Company Reported Apparent Cause: ☐ Corrosion ☐ Damage by Outside Force

☐ Damage by Natural Forces ☐ Accidentally Caused by the Operator

☐ Construction/Material Defect ☐ Equipment Malfunction ☐ Other ______________________

Rupture ? ☐ Yes ☐ No

Leak ? ☐ Yes ☐ No

Fire? ☐ Yes ☐ No

Explosion?: ☐ Yes ☐ No

Evacuation?: ☐ Yes ☐ No Number of Persons? __________ Area? __________

Narrative Summary
One paragraph summary description of the Incident/Accident which will give interested persons sufficient information to make them aware of the basic scenario and facts.

Region/State: ______________________ **Reviewed by:** ______________________

Principle Investigator: ______________________ **Title:** ______________________

Date: ______________________ **Date:** ______________________

Failure Location & Response	
Location (City, Township, Range, County/Parish): (Acquire Map)	
Address or M.P. on Pipeline: ρ	Type of Area (Rural, City): ρ
Date:	Time of Failure:
Time Detected:	Time Located:
How Located:	

NRC Report #: (Attach Report)	Time Reported to NRC:	Reported by:

Type of Pipeline:

Gas Distribution	Gas Transmission	Hazardous Liquid	LNG
☐ LP	☐ Interstate Gas	☐ Interstate Liquid	☐ LNG Facility
☐ Municipal	☐ Intrastate Gas	☐ Intrastate Liquid	
☐ Public Utility	☐ Jurisdictional Gas Gathering	☐ Offshore Liquid	
☐ Master Meter	☐ Offshore Gas	☐ Jurisdictional Liquid Gathering	
	☐ Offshore Gas - High H_2S	☐ CO_2	

Pipeline Configuration (Regulator Station, Pump Station, Pipeline, etc.):

Operator/Owner Information	
Owner:	Operator:
Contact:	Company Official:
Address:	Title:
City: State:	Address:
Phone No.: Fax No.:	City: State:
DRUG TESTING	☐ **N/A**
Contact:	Phone No.:

Damages	
Product/Gas Loss or Spill(1): Amount Recovered: Estimated Amount $:	Estimated Property Damage $: Associated Damages(2) $:
Description of Property Damage:	

Customers out of Service: ☐ Yes ☐ No Number: ________________

Suppliers out of Service: ☐ Yes ☐ No Number: ________________

(1) Initial Volume Lost or Spilled

(2) Including Cleanup Cost

Fatalities and Injuries

Fatalities:	☐ Yes	☐ No	Company:	________	Contractor:	________	Public:	________
Injuries - Hospitalization:	☐ Yes	☐ No	Company:	________	Contractor:	________	Public:	________
Injuries - Non-Hospitalization:	☐ Yes	☐ No	Company:	________	Contractor:	________	Public:	________
Total Injuries (including Non-Hospitalization):			Company:	________	Contractor:	________	Public:	________

Name	Age	M/F	Job Function	Yrs w/ Comp.	Yrs Exp.	Type of Injury

Drug/Alcohol Testing ☐ *N/A*

Were all employees that could have contributed to the incident, Post Accident tested within the 2 hour time frame for alcohol or the 32 hour time frame for all other drugs?

☐ Yes ☐ No

Job Function	Time of Test	Location	Results		Type of Drug
			Pos.	Neg.	

System Description

Describe the Operator's System:

Pipe Failure Description ☐ *N/A*

Length of Failure (inches, feet, miles): ρ

Position (Top, Bottom, include position on pipe, 6 O'clock): ρ	Description of Failure (Corrosion Gouge, Seam Split): ρ

Laboratory Analysis: ☐ Yes ☐ No
Performed by:

Preservation of Failed Section or Component: ☐ Yes ☐ No
If Yes - Method:

In Custody of:

Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Direction of Flow.

Component Failure Description	☐ N/A
Component Failed:	ρ
Manufacturer:	Model:
Pressure Rating:	Size:
Other (Breakout Tank, Underground Storage):	

Pipe Data	☐ N/A
Material:	Wall Thickness/SDR:
Diameter (O.D.):	Installation Date:
SMYS:	Manufacturer:
Longitudinal Seam:	Type of Coating:
Pipe Specifications (API 5L, ASTM A53, etc.):	

Joining	☐ N/A
Type:	Procedure:
NDT Method:	Inspected: ☐ Yes ☐ No

Pressure @ Time of Failure @ Failure Site				☐ N/A
Pressure @ Failure Site:		Elevation @ Failure Site:		
Pressure Readings @ Various Locations:			Direction from Failure Site	
Location/M.P./Station #	Pressure	Elevation	Upstream	Downstream

Upstream Pump Station Data	☐ N/A
Type of Product:	API Gravity:
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure(3):	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Upstream Compressor Station Data	☐ N/A
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure(3):	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Operating Pressure	☐ N/A
Max. Allowable Operating Pressure:	Determination of MAOP:
Actual Operating Pressure:	
Method of Over Pressure Protection:	
Relief Valve Set Point:	Capacity Adequate?: ☐ Yes ☐ No

(3) Obtain Event Logs and Pressure Recording Charts

Integrity Test After Failure

☐ ***N/A***

Pressure Test Conducted in place? (Conducted on Failed Components or Associated Piping): ☐ Yes ☐ No

If NO, Tested after removal?: ☐ Yes ☐ No

Method?:

Describe any failures during the test.

Pressure Test History

☐ ***N/A***

	Date	Test Medium	Pressure	Duration	% SMYS
Installation:					
Last:					
Other:					

Any problems occur during any of the Pressure Tests?:

Soil/water Conditions @ Failure Site

☐ ***N/A***

Condition of and type of Soil around Failure Site (Color, Wet, Dry, Frost Depth):

Type of Backfill (Size and Description):

Type of Water (Salt, Brackish):

Water Analysis[4]: ☐ Yes ☐ No

(4) Attach Copy of Water Analysis Report

External Pipe or Component Examination	☐ N/A
External Corrosion?: ☐ Yes ☐ No ρ	Coating Condition (Disbonded, Non-existent): ρ
Description of Corrosion: ρ	
Description of Failure surface (Gouges, Arc Burns, Wrinkle Bends, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of Origin):	
Above Ground: ☐ Yes ☐ No ρ	Buried: ☐ Yes ☐ No ρ
Stress Inducing Factors: ρ	Depth of Cover: ρ

Cathodic Protection	☐ N/A
P/S (Surface):	P/S (Interface):
Soil Resistivity: pH:	Date of Installation:
Method of Protection?:	
Did the Operator have knowledge of Corrosion before the Incident?: ☐ Yes ☐ No	
How Discovered? (Close Interval Survey, Instrumented Pig, Annual Survey, Rectifier Readings):	

Internal Pipe or Component Examination	☐ N/A
Internal Corrosion: ☐ Yes ☐ No ρ	Injected Inhibitors: ☐ Yes ☐ No
Type of Inhibitors:	Testing: ☐ Yes ☐ No
Results (Coupon Test, Corrosion resistance Probe):	
Description of Failure surface (MIC, Pitting, Wall Thinning, Chevrons, Fracture Mode, Point of Origin):	
Cleaning Pig Program: ☐ Yes ☐ No	Gas and/or Liquid Analysis: ☐ Yes ☐ No
Results of Gas and/or Liquid Analysis(5):	
Internal Inspection Survey: ☐ Yes ☐ No	Results(6):
Did the Operator have knowledge of Corrosion before the Incident?: ☐ Yes ☐ No	
How Discovered? (Instrumented Pig, Coupon Testing):	

(5) Attach Copy of Gas and/or Liquid Analysis Report
(6) Attach Copy of Internal Inspection Survey Report

Outside Force Damage

☐ *N/A*

Responsible Party:	Telephone No.:
Address:	
Work Being Performed:	
Equipment Involved: ρ	Called One Call System?: ☐ Yes ☐ No
One Call Name:	One Call Report #(7):
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures: ☐ Yes ☐ No	
Pipeline Marking Type: ρ	Location: ρ
State Law Damage Prevention Program Followed?: ☐ Yes ☐ No ☐ No State Law	
Notice Required: ☐ Yes ☐ No	Response Required: ☐ Yes ☐ No
Was Operator Member of State One Call?: ☐ Yes ☐ No	Was Operator on Site?: ☐ Yes ☐ No
Is OSHA Notification Required?: ☐ Yes ☐ No	

Natural Forces

☐ *N/A*

Description (Earthquake, Tornado, Flooding, Erosion):

Failure Isolation

☐ *N/A*

Squeeze Off/Stopple Location and Method: ρ	
Valve Closed - Upstream: Time:	I.D.: M.P.:
Valve Closed - Downstream: Time:	I.D.: M.P.:
Pipeline Shutdown Method: ☐ Manual ☐ Automatic ☐ SCADA ☐ Controller ☐ ESD	
Failed Section Bypassed or Isolated:	
Performed By:	Valve Spacing:

(7) Attach Copy of One Call Report

Odorization ☐ *N/A*

Gas Odorized: ☐ Yes ☐ No	Concentration of Odorant (Post Incident at Failure Site):
Method of Determination:	% LEL: % Gas In Air:
	Time Taken:
Was Odorizer Working Prior to the Incident: ☐ Yes ☐ No	Type of Odorizer (Wick, By-Pass):
Odorant Manufacturer: Model:	Type of Odorant:
Amount Injected:	Monitoring Interval (Weekly):

Odorization History (Leaks Complaints, Low Odorant Levels, Monitoring Locations, Distances from Failure Site):

Weather Conditions ☐ *N/A*

Temperature:	Wind (Direction & Speed):
Climate (Snow, Rain):	Humidity:

Was Incident preceded by a rapid weather change: ☐ Yes ☐ No

Weather Conditions Prior to Incident (Cloud Cover, Ceiling Heights, Snow, Rain, Fog):

Gas Migration Survey ☐ *N/A*

Bar Hole Test of Area: ☐ Yes ☐ No	Equipment Used:

Method of Survey (Foundations, Curbs, Manholes, Driveways, Mains, Services)(8): ρ

Environment Sensitivity Impact ☐ *N/A*

Location (Nearest Rivers, Body of Water, Marshlands, Wildlife Refuge, City Water Supplies that could be or were affected by the medium loss.): ρ

OPA Contingency Plan Available?: ☐ Yes ☐ No Followed?: ☐ Yes ☐ No

Class Location ☐ *N/A*

Class:	Determination:

Odorization Required?: ☐ Yes ☐ No

(8) Plot on Site Description Page

Maps & Records	☐ N/A

Are Maps and Records Current?[9]: ☐ Yes ☐ No

Leak Survey History	☐ N/A

Leak Survey History (Trend Analysis, Leak Plots):

Pipeline Operation History	☐ N/A

Description (Repair or Leak Reports, Exposed Pipe Reports):

Did a Safety Related Condition Exist Prior to Failure?: ☐ Yes ☐ No Reported?: ☐ Yes ☐ No

Unaccounted For Gas:

Over & Short/Line Balance (24 hr., Weekly, Monthly/Trend):

Operator/Contractor Error	☐ N/A

Name:	Job Function:
Title:	Years of Experience:
Training (Type of Training, Background):	
Type of Error (Inadvertent Operation of a Valve):	
Procedures that are required:	
Actions that were taken:	
Pre-Job Meeting (Construction, Maintenance, Blow Down, Purging, Isolation):	
Prevention of Accidental Ignition (Tag & Lock Out, Hot Weld Permit):	
Procedures conducted for Accidental Ignition:	
Was a Company Inspector on the Job?: ☐ Yes ☐ No	
Was an Inspection conducted on this portion of the Job?: ☐ Yes ☐ No	
Additional Actions (Contributing factors may include number of hours at work prior to failure or time of day work being conducted):	

(9) Obtain Copies of Maps and Records

Operator/Contractor Error				☐ ***N/A***
Training Procedures:				
Operation Procedures:				
Controller Activities:				
Name	Title	Years Experience	Hours on Duty Prior to Failure	Shift
Alarm Parameters:				
High/Low Pressure Shutdown:				
Flow Rate:				
Procedures for Clearing Alarms:				
Type of Alarm:				
Company Response Procedures for Abnormal Operations:				
Over/Short Line Balance Procedures:				
Frequency of Over/Short Line Balance:				
Additional Actions:				

Additional Actions Taken by the Operator

Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating downstream Pumps):

Photo Documentation ρ

Overall Area from best possible view.
Pictures from the four points of the compass.
Failed Component.
Operator Actions.
Damages in Area.
Address Markings.

Photo No.	Description	Roll No.	Photo No.	Description	Roll No.
1			1		
2			2		
3			3		
4			4		
5			5		
6			6		
7			7		
8			8		
9			9		
10			10		
11			11		
12			12		
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24			24		
25			25		
26			26		
27			27		
28			28		
29			29		
30			30		
31			31		
32			32		
33			33		
34			34		
35			35		
36			36		

Type of Camera:

Film ASA:

Video Counter Log[(10)]:

(10) Attach Copy of Video Counter Log

Additional Information Sources	
Phone Number	Name
Police:	Contact:
Fire Dept.:	Contact:
State Fire Marshall:	Contact:
State Agency:	Contact:
NTSB:	Contact:
EPA:	Contact:
FBI:	Contact:
ATF:	Contact:
OSHA:	Contact:
Insurance Co.:	Contact:
FRA:	Contact:
MMS:	Contact:
Television:	Contact:
Televison	Contact:
Newspaper:	Contact:
Other:	Contact:

Persons Interviewed		
Name	Title	Phone Number

Event Log

Sequence of events prior, during and after the incident by time. (Consider the events of all parties involved in the incident, Fire Department and Police reports, Operator Logs and other government agencies.)

Time	Event

Investigation Contact Log

Time	Date	Name	Description

Failure Investigation Documentation Log

Operator: Unit #: CPF #: Date:

Appendix Number	Documentation Description	Date Received	FOIA	
			Yes	No

Site Description

Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc.. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

Chain of Custody

O&M Form #1.03C

Reference: 49 CFR 195.60 **Date Revised: Sept 2014**

Project Number:	
Owner of Material:	
Origin of Record:	
Description of Item:	
Date:	
By:	

Release By:			**Received By:**		
Name:	**Company:**	**Date:**	**Name:**	**Company:**	**Date:**

Note Any Alterations to Materials:
By:

PHMSA HAZARDOUS LIQUID
JURISDICTIONAL DETERMINATION
Per 195.0, 195.1, 195.2, 195.3, 195.6, 195.11, 195.12
Form #1.04A

Reference Documents Needed:

1. 49 CFR 19.0, 195.1, 195.2, 195.3, 195.6, 195.11, 195.12
2. Liquid O&M procedure, #1.04
3. PHMSA Part 195 Jurisdictional Flow Chart (revised Sept 14, 2011)

Instructions:

Using referenced regulations and PHMSA jurisdictional flow chart as a guide, determine if the line meets the definition of:

- Regulated transmission
- Regulated rural gathering, or
- Regulated low stress

Finally, if the pipeline is determined to be jurisdictional, then plan and schedule appropriate maintenance as required by the regulations.

PHMSA Hazardous Liquid Jurisdictional Determination Documentation:

1.

Date of Determination:

2.

Names of Personnel Making Determination:

3.

Basic Description of Line and Operations: **(include MAOP, SMYS, and basic description)**	
Name of Segment:	
MAOP:	
20% SMYS:	[((2x SMYS x wall thickness)/diameter) x .20]
Basic Description:	

4.

Describe why pipeline meets specific definition of transmission, rural gathering, low stress, or non-regulated.

5.

Will a pipeline management of change (MOC) process need to be initiated for the line? **If yes, document using corporate MOC procedures that may include notification of determination, new equipment required (cathodic protection, line markers, etc.), and initiation of new maintenance schedules.**

7.

Conclusion (determination and action required):
Determination: Attached Referenced Documents: Action Required: •

Signature

Date

GENERAL INSTRUCTIONS

All section references are to Title 49 of the Code of Federal Regulations (49 CFR). The Hazardous Liquid or Carbon Dioxide Pipeline Systems Annual Report has been revised as of calendar year 2010 affecting submissions for 2010 and beyond. This Annual Report is required per §195.49 and must be filed per §195.58. Read through the Annual Report and instructions carefully before beginning to complete the Report. Where common data elements exist between this Report and an operator's NPMS submission, the data submitted by the operator on their Annual Report should be the same as the data submitted through NPMS when possible. (Additionally, and in order to align an operator's NPMS submission with their Annual Report data, PHMSA suggests that operators send their NPMS submission to PHMSA by June 15, representing pipeline assets as of December 31 of the previous year.)

Each operator must annually complete and submit DOT Form PHMSA F 7000–1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state. In order to improve the accuracy of reported data, operators are requested to review prior years' Reports in order to validate that their reported numbers are accurate, or to identify and correct inconsistencies or errors that are either found or that may exist in any previously reported data. Operators should file Supplemental Reports as necessary, including those supplementing prior years' Reports.

The terms "barrel", "breakout tank", "carbon dioxide", "flammable product", "gathering line", "hazardous liquid", "highly volatile liquid (HVL)", "intrastate pipeline", "interstate pipeline", "low stress pipeline", "maximum operating pressure", "offshore", "operator", "Outer Continental Shelf (OCS)", "petroleum", "petroleum product", "pipe or line pipe", "pipeline or pipeline system", "pipeline facility", "rural area", "specified minimum yield strength (SMYS)", "stress level", "toxic product", and "Unusually Sensitive Area (USA)" are defined in §195.2.

If you need copies of the Form PHMSA F 7000-1.1 and/or instructions they can be found on the Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking Data and Statistics and then selecting the Forms hyperlink. If you have questions about this Report or these instructions, please call PHMSA's Information Resources Manager at 202-366-8075.

ONLINE REPORTING REQUIREMENTS

The following two requirements must be fulfilled prior to submitting data online:

1. You must have an Office of Pipeline Safety (OPS) provided Operator Identification Number (OPID) and Personal Identification Number (PIN)/password. If you do not have one, please complete and submit the form located on the OPS Online Data Entry and Operator Registration System New Operator Registration web site at http://opsweb.phmsa.dot.gov/cfdocs/opsapps/pipes/new_operator.cfm to obtain one.

2. You must have a Username and Password obtained by registering through the PHMSA Portal. If you have an OPS OPID and PIN/password, you may obtain a Username and Password through the PHMSA Portal.

Important: Each operator without an OPID is to plan accordingly and allow for several weeks prior to the due date of the Report to obtain their OPID from PHMSA.

REPORTING METHOD

Annual Reports must be submitted online unless an alternate method is approved (see Alternate Reporting Methods below). Use the following procedure:

1. Navigate to the Pipeline Safety Community main page, http://www.phmsa.dot.gov/pipeline, click the **ONLINE DATA ENTRY** link listed.

2. Click on the Annual Hazardous Liquid or Carbon Dioxide Pipeline Systems Report link

3. Enter Operator Identification Number (OPID) and PIN. [If an operator does not have an OPID or a PIN, the **ONLINE DATA ENTRY** page includes directions on how to obtain one.]

4. Click A**dd** to begin data entry for a new calendar year's Report. [For Supplemental Reports, click on the Report ID and select **Modify** to make corrections or add new information.]

5. To save intermediate work without formally submitting it to PHMSA, click **Save**.

6. Click **Submit** when you have completed the Report (for either an Initial Report or a Supplemental Report) and are ready to initiate formal submission of your Report to PHMSA.

7. A confirmation page will appear for you to print and save for your records.

Alternate Reporting Methods

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternate reporting method. Operators must follow the requirements in §195.58(d) to request an alternate reporting method and must comply with any conditions imposed as part of PHMSA's approval of an alternate reporting method.

SPECIFIC INSTRUCTIONS

Make an entry in each block for which data is available. Estimate data only if necessary. Avoid entering any data as **UNKNOWN or 0 (zero)** except where zero is appropriate to indicate that there were no instances or amounts of the attribute being reported.

Do not report miles of pipe, pipe segments, or pipeline in feet. When reporting mileages that are less than 1 mile or when reporting portions of a mile, convert feet into a decimal notation (e.g. 2,640 feet = .5 miles) and report mileage using decimals rounded to the nearest tenth of a mile. Operators may round all mileages that are greater than 1 mile to the nearest mile. Do not use fractions.

Enter the Calendar Year for which the Report is being filed, bearing in mind that reporting requirements are for the preceding calendar year (i.e., for the June 15, 2011 deadline, the Report should provide information for assets as they existed at the end of the 2010 calendar year).

Select **Initial Report** if this is the original filing for the calendar year. Select **Supplemental Report** if this is a follow-up to a previously filed Report to amend or correct information for that calendar year. On Supplemental Reports, enter all information requested in Parts A and N, and only the new or revised information for the other Parts of the Report, completing Part O as required.

Report miles of pipe, pipe segments, or pipeline in the system at the end of the reporting year, including any additions or deletions to the system occurring during that year. Report other data for the duration of the calendar year as appropriate. Adhere to definitions in 49 CFR 195 when reporting mileage and other data.

For a given OPID, a separate Annual Report is to be completed for each Commodity Group within that OPID. The separate Annual Report is to cover all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within that OPID that serve to transport that Commodity Group. As an example, if an operator uses a single OPID and has one set of facilities and/or pipelines that transport crude oil and another that transports refined products, this operator is to file two Annual Reports – one Annual Report covering all the facilities and/or pipelines that transport crude oil and another Annual Report covering all the facilities and/or pipelines that transport refined products. If another operator utilizes two OPIDs with both crude oil and refined products facilities and/or pipelines within each OPID, that operator must file four separate Annual Reports.

Parts A – E are to be completed once for each Annual Report, namely once for each Commodity Group within an OPID, covering ALL of the pipelines and/or facilities (both Interstate and Intrastate) and combining all states in which those assets exist. Separate reporting by state is not required for these Parts. Parts F – M, however, are to be reported separately for Interstate and for Intrastate facilities, or by state, or both depending on the instructions pertaining to each Part.

PART A - OPERATOR INFORMATION

Complete all 8 sections of Part A before continuing to the next Part.

1. **Operator's 5 digit Identification Number (OPID)**

   All operators that meet the definition of an "operator" under §195.2 must have a PHMSA-assigned Operator Identification Number (also known as an OPID). If the person completing the Report does not know the OPID for the system being reported, this information may be requested from PHMSA's Information Resources Manager at 202-366-8075. (See instructions on the ONLINE DATA ENTRY page as described above.)

2. **Name of Company or Establishment**

   This is the company name used when registering for an OPID and PIN in the Online Data Entry System. When completing the Report online, the Name of Operator is automatically filled in based on the OPID entered in Part A, Question 1. If the name that appears does not coincide with the OPID, contact PHMSA's Information Resources Manager.

   If the company corresponding to the OPID is a subsidiary, enter the name of the parent company.

3. **Individual where additional information may be obtained**

   Enter the name, title, email address, and telephone number of the individual who should be contacted if additional information regarding this Report submission is needed.

4. Headquarters address

Enter the address and phone number of the operator's corporate headquarters.

5. This Report pertains to the following Commodity Group

It is a PHMSA requirement (§195.49) that operators submit separate Reports for each Commodity Group within a particular OPID. It should be noted that these Commodity Groups, though similar to the Commodity Groups used when reporting accidents to PHMSA, are not precisely the same when it comes to the reporting of pipelines that transport fuel grade ethanol and ethanol blends. Whereas fuel grade ethanol and ethanol blends are grouped in the same category for accident reporting purposes, pipelines that transport fuel grade ethanol have their own Commodity Group for the purposes of Annual Reporting. Pipelines that transport ethanol in a blended state should be reported as Refined and/or Petroleum Product (non-HVL) in an operator's Annual Report.

File a separate Annual Report for each of the following **Commodity Groups** (as further defined in §195.2):

Crude Oil - unrefined oil consisting mainly of hydrocarbons.

Refined and/or Petroleum Product (non-HVL) – flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds. Examples include motor gasoline, diesel fuel, fuel oil, aviation gasoline, jet fuel, kerosene, acetone, benzene, MTBE, naphtha, or other non-HVL petroleum products. For the sake of this Report, "petroleum product" is meant to be synonymous with "refined product".

Highly Volatile Liquids (HVLs) – a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa at 37.8º C (100º F). Examples include ethane, ethylene, propane, propylene, butylene, and anhydrous ammonia (NH_3).

Carbon Dioxide (CO_2) – a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Fuel Grade Ethanol – a clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. This Commodity Group is to be selected only if the pipeline and/or pipeline facility is used predominantly to transport ethanol which has NOT been blended with petroleum products. This commodity is sometimes also known as "neat" ethanol. Pipelines that transport ethanol in a blended state should be reported as Refined and/or Petroleum Product (non-HVL).

Note: When a single pipeline or facility serves to transport two or more of the above Commodity Groups, that pipeline or facility should be reported only once, reporting within the Commodity Group for the commodity that is transported most predominantly during the year being reported.

6. Integrity Management Program

Indicate here whether any portion(s) of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are subject to the integrity management (IM) requirements of §195.452.

Pipelines and/or pipeline facilities that include segments that could affect high consequence areas (HCAs) are required to have an IM Program in accordance with §195.452. For the purposes of this question and, more generally, this Report, do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Select the box indicating that portions of *SOME or ALL* of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are included in an IM Program as required by §195.452, and complete other Parts of this Report in accordance with Part A, Question 8.

If *NO PORTIONS* of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are included in an IM Program as required by §195.452, select the box indicating such. In this case, Parts B, F, G, L, and O need not be completed.

7. Interstate and/or Intrastate pipeline

Pipeline assets included within a particular Commodity Group under a single OPID may be either interstate, intrastate, or both. Select the appropriate box or boxes to indicate whether the pipelines and/or pipeline facilities for the OPID and Commodity Group are interstate or intrastate or both. List the two-letter state abbreviation for each state in which reported interstate and/or intrastate assets are located.

The terms Interstate and Intrastate pipeline are defined in §195.2. Appendix A to 49 CFR 195 contains PHMSA's Statement of Policy and Interpretation on the delineation between interstate and intrastate pipelines, and provides additional guidance.

8. Does this Report represent a change from last year's final reported information for one or more of the following Parts?

Select "This Report is for calendar year 2010 reporting or is a first-time Report…" only for the reporting of calendar year 2010 information, including any supplements to that information, or if this is a first-time filing of an Annual Report for these facilities. Because this revision of the Annual Report will be used for the first time to report information for calendar year 2010, some of the "Parts" of this Report referred to in this question are new and, therefore, no comparable information will have been reported for the prior year. For calendar year 2010 only, respond to this question by selecting the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable. Similarly, if no Annual Report has been previously filed for this operator, OPID, Commodity Group, or pipelines and/or pipeline facilities, or for other reasons, select the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable.

For calendar year submissions beyond 2010, an option has been created to allow the operator to provide information for relevant Parts when certain portions of the information have not changed.

Select "No" if there are no changes in the information reported for the current reporting year compared against the prior calendar year for Parts B, D, E, H, I, J, K, L, or M for the Commodity Group reported.

It should be noted that PHMSA expects that the data describing volume transported (Part C) and integrity management activity (Parts F and G) will change each year. Therefore, Part C, describing volume transported, must be completed every year. Additionally, those Parts of this Report related to integrity management activity (Parts F, G and O) must be completed every year by every operator with portions of pipelines and/or pipeline facilities subject to PHMSA's IM regulations as indicated in Part A, Question 6.

When there are changes in the information reported for the current reporting year compared against the prior calendar year, these changes can occur for one of the two following reasons:

1) New information or new calculations may have changed the understanding of pipeline and/or pipeline facility data, leading to differences in some data elements reported on the Annual Report in the previous year's Report, even though the physical pipeline(s) and/or pipeline facility(ies) themselves have not changed; or,

2) The pipeline(s) and/or pipeline facility(ies) may have changed – either physically or operationally.

Select one or both of the two "Yes" boxes if reported system information has changed. If the change is due to a change in the pipelines and/or pipeline facilities and/or operations (number 2 above), select the appropriate box or boxes to indicate the nature of the change(s). If "Other" is selected, provide a brief description of the change.

- Merger/acquisition involves a change in ownership or operating responsibility that would likely result in increases or other changes in the reported miles of pipeline in most Parts of the Report.

- Divestiture involves a change in ownership or operating responsibility that would likely result in decreases or other changes in the reported miles of pipeline.

- New construction or new installation that would likely result in increases or other changes in the reported miles of pipeline, including rerouting of pipelines.

- Conversion of service, change in commodity transported, or change in MOP (maximum operating pressure).

    - Conversion to service means conversion to transportation of hazardous liquids under §195.5 that would likely result in increases or other changes in the reported miles of pipeline. (This is selected if a pipeline that was previously used to transport a commodity or material that was not covered under 49 CFR 195, such as water, is being converted to move a commodity that is covered under 49 CFR 195, such as a crude oil line.)

- Change in commodity transported means a change in the commodity predominately transported and thus in the Commodity Group reported in Part A, Question 5. (This is selected if the previous commodity moved in a pipeline covered under 49 CFR 195 is changed to a different commodity moved under 49 CFR 195, for example a refined products line being changed to a crude oil line.)

- Change in MOP (maximum operating pressure) could result in changes to the mileage of pipeline operating in different categories of hoop stress (i.e., percent SMYS (Specified Minimum Yield Strength)) as reported in Part J.

- "Abandoned," as defined in § 195.2, means permanently removed from service. All pipeline mileage not permanently removed from service should be reported, including pipelines and/or pipeline facilities considered to be idled.

- Change in various aspects of an operator's IM Program may result in changes to information reported in Parts B, F, and/or G.

- Change in an operator's OPID number – or changes in pipelines and/or pipeline facilities covered by a particular OPID number – may result in changes throughout the Annual Report.

For the designated Commodity Group, complete Parts B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within this OPID. Separate reporting by state is not required for these Parts. Data reported should represent the system in total, including all states in which system assets are located.

PART B - MILES OF PIPE BY LOCATION

Report in Part B the total miles of Onshore and Offshore pipe that could affect High Consequence Areas (HCAs) and are thus in the IM Program. Operators should NOT double-count mileage for a single segment of pipeline that may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Also, do not include miles of pipeline that could not affect an HCA but which are included in the IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). This Part should be left blank if no portions of the pipelines and/or pipeline facilities covered by this OPID are in an IM Program, as indicated in Part A, Question 6.

PART C – VOLUME TRANSPORTED IN BARREL-MILES

Barrel-miles means the total of the number of barrels transported multiplied by the distance in miles the specific barrels were moved. Report the volume of all commodities transported during the calendar year for this Commodity Group. Include the annual total volume transported in barrel-miles for all states and for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within this OPID and for this Commodity Group. Volumes of any Commodity Group transported in addition to the Commodity Group predominately transported through these pipelines and/or pipeline facilities should also be reported in Part C within the proper row. Example: If 2,000,000 barrels of crude oil were moved in one 35-mile onshore pipeline from end to end and 80,000,000 barrels of crude oil were moved in a second 1,000-mile onshore pipeline from end to end, both occurring in a given reporting year, then the total volume transported in barrel-miles for the Crude Oil Commodity Group for Onshore is equal to (2,000,000 x 35) + (80,000,000 x 1,000) = 70,000,000 + 80,000,000,000 = 80,070,000,000 Onshore Crude Oil Barrel-Miles. If, additionally, 500,000 barrels of an HVL were moved in the same 35-mile onshore pipeline from end to end, then 17,500,000 barrel-miles (500,000 x 35) should also be included in Part C for the Crude Oil Commodity Group under the "HVL" row and "Onshore" column in the table.

PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION

For steel pipe only, report the total miles of Onshore and Offshore pipe that is cathodically protected and cathodically unprotected subdivided, in each case, into the amount that is bare and the amount that is coated pipe. **COATED** means steel pipe coated with an effective hot or cold applied dielectric coating or wrapper. Enter zero (0) in any cell for which the pipeline system includes no mileage. Do not leave any cells blank.

PART E – MILES OF ELECTRIC RESISTANCE WELDED (ERW) PIPE BY WELD TYPE AND DECADE

Report here only pipe that was manufactured using an electric resistance welded (ERW) process. Report separately, each by decade installed, the miles of installed pipe manufactured using a high-frequency ERW process and that manufactured with a low-frequency or DC ERW process.

"High Frequency" means the ERW pipe was manufactured using a high frequency ERW process. High frequency ERW pipe is pipe that was manufactured using a high frequency electrical current, usually about 450 thousand Hertz (kHz) to provide heat for fusion of the weld seam. Most pipe manufactured using this process has been manufactured since the late 1960s.

"Low Frequency" means the ERW pipe was manufactured using a low frequency ERW process. Low frequency ERW pipe is pipe that was manufactured using a low frequency, usually about 250 Hertz (Hz) alternating electrical current to provide heat for fusion of the weld seam. Most pipe manufactured using this process was manufactured prior to 1970.

Flash welded pipe (EFW) is NOT a type of ERW pipe and should NOT be included in the reported numbers for this Part E.

"DC" means direct current.

Make an entry in each block. PHMSA recognizes that some companies may have pipe for which installation records may not exist. If records do not exist, enter estimates of the totals of such mileage in the "Pre-40 or Unknown" section of Part E. Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

For the designated Commodity Group, complete Parts F and G one time for all INTERstate pipelines and/or pipeline facilities included within this OPID and multiple times as needed for the designated Commodity Group for each State in which INTRAstate pipelines and/or pipeline facilities included within this OPID exist.

For example: Consider a set of crude oil pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts F and G should be completed four times for this set of crude oil pipeline systems – once for all INTERstate assets (combined) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located (separately).

Each time Parts F and G are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities. If INTRAstate, enter in the space provided the two-letter postal abbreviation for the state.

PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION

Report all integrity assessments (inspections) required by PHMSA's IM regulations which were conducted and actions which were taken during the calendar year based on inspection results. Include all inspections conducted in the reporting period calendar year including baseline assessments and re-assessments. Do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Part F is subdivided into six (6) sections.

Section 1 - Mileage inspected in calendar year using the following In-Line Inspection (ILI) tools.

Report the mileage inspected using each of the listed tool types. Include total miles inspected, not just the mileage that could affect a high consequence area. Where multiple ILI tools are used (e.g., a metal loss tool and a deformation tool), report the mileage in both categories. Where a combination tool is used (i.e., a single tool with multiple capabilities), report the mileage separately in each category included as part of the combination. Thus, the total mileage inspected during the calendar year (the sum of the mileage reported for individual tools) may be greater than the actual number of physical pipeline miles on which ILI inspections were run.

Enter zero (0) for any tool which was not used for IM assessments during the year. Leave no rows blank.

Section 2 - Actions taken in calendar year based on In-Line Inspections.

Include all actions taken during the calendar year that resulted from information obtained during an ILI inspection. This should include actions taken as a result of information developed during ILI inspections conducted during the calendar year PLUS actions taken as a result of ILI inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on review of ILI results but which did not actually occur during the reporting year.

Report in items a. and b. the total number of anomalies excavated and repaired based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA. (The operator's criteria for anomalies in segments that could affect an HCA must be at least as conservative as those required by the regulations).

Report in a. the total number of anomalies excavated, recognizing that multiple anomalies may be exposed in a single excavation.

Report in b. only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Report in c. only the anomalies in pipeline segments that could affect an HCA that were repaired because they met one of the three repair criteria in the IM regulations. (The total of repairs reported in item c. should not exceed the total number of repairs reported in item b.)

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 3 – Mileage inspected and actions taken in calendar year based on Pressure Testing.

Report in a. the total miles inspected by pressure testing, including both mileage that could affect an HCA and mileage that could not affect an HCA.

Report in b. the total number of test failures (ruptures and leaks) repaired on all mileage tested during the year.

Report in c. the ruptures and in d. the leaks repaired ONLY in segments that could affect an HCA.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank. Enter zero (0) in all rows of section 3 if no IM assessments were conducted by pressure test during the year.

Section 4 - Mileage inspected and actions taken in calendar year based on ECDA (External Corrosion Direct Assessment)

Include all actions taken during the calendar year that resulted from information obtained during an ECDA inspection. This should include actions taken as a result of information developed during ECDA inspections conducted during the calendar year PLUS actions taken as a result of ECDA inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on ECDA inspection results but which did not actually occur during the reporting year.

Report in b. the total number of anomalies excavated and repaired based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect an HCA. (The operator's criteria for anomalies in segments that could affect an HCA must be at least as conservative as those required by the regulations).

Report in c. the number of anomalies in pipeline segments that could affect an HCA that were repaired because when excavated and examined they met one of the three repair criteria in the IM regulations.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 5 – Mileage inspected and actions taken in calendar year based on Other Inspection Techniques

IM regulations allow operators to use other assessment techniques provided that they notify PHMSA (or states exercising regulatory jurisdiction) in advance. Report here the mileage inspected and actions taken as a result of inspections conducted using any technique other than those covered in Sections 1-4 of Part F.

As for the other techniques, include all actions taken during the calendar year that resulted from information obtained during an inspection using another technique. This should include actions taken as a result of information developed as part of inspections conducted during the calendar year PLUS actions taken as a result of inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on inspection results but which did not actually occur during the reporting year.

Report only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 6 - Total Mileage Inspected (all Methods) and Actions Taken.

These entries will be calculated automatically based on data entered in Sections 1-5. For operators completing a paper form as a result of PHMSA approval to use alternate reporting measures (see above), report here the total mileage inspected and actions taken as the sum of the indicated elements from other sections.

PART G – MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (segment miles that could affect HCAs ONLY)

Report the number of miles of pipeline that could affect an HCA (as reported in Part B) that were assessed during the calendar year pursuant to §195.452. Report separately the number of miles inspected for baseline assessments (e.g., initial baseline assessments and new baseline assessments, including those which occur due to new pipelines or facilities, new or newly identified HCAs, new spill flow paths, new spill volume calculations, low-stress pipe for which the baseline assessment deadline has not yet passed, etc.) and miles for which a reassessment was conducted. Do not include pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.).

Report only assessments that were completed during the calendar year. These “completed assessments” are defined consistently with FAQ 4.13 http://primis.phmsa.dot.gov/iim/faqs.htm. ***The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed***, not including repair activities. That is, when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with external corrosion direct assessment is made, or the date on which "other technology" for which an operator has provided timely notification is conducted.

Operators should report in Part G the total number of miles actually assessed. This differs from Part F where operators report the number of miles inspected by individual inspection methods where some mileage may be reported multiple times. Operators should note that the mileages reported as completed assessments in Part G should be a subset of the total miles of onshore/offshore pipe that could affect High Consequence Areas reported in Parts B and L. Operators should validate the total completed and scheduled assessment mileage in their Assessment Plans with the mileage reported here. The comparison of these two numbers will highlight any discrepancies resulting from new HCA segments being added or deleted, acquired or sold, or idled[1] or converted, and which need to be properly reflected in this Report.

[1] While the regulations do not recognize an intermediate state between operational and abandoned (see instructions for Part A, Question 8 above), PHMSA has acknowledged that operators sometimes maintain some of their pipe in an idle status in which conducting IM assessments is impractical. This consideration of “idle” pipe is discussed in FAQ 2.3 on the PHMSA IM website (http://primis.phmsa.dot.gov/iim/faqs.htm).

For the designated Commodity Group, complete Parts H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities separately for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities separately for each State in which INTRAstate systems exist within this OPID.

For example: Consider a set of crude oil pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts H, I, J, K, L, and M should be completed ten times for this set of crude oil pipeline systems – seven times for INTERstate assets (once for each of the seven states in which INTERstate assets are located) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located.

Each time the remaining Parts are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities, and enter in the space provided the two-letter postal abbreviation for the state.

PART H – MILES OF PIPE BY NOMINAL PIPE SIZE (NPS)

Report the miles of pipe by Nominal Pipe Size (NPS) and location for both onshore and offshore locations. Enter the appropriate mileage in the corresponding nominal size blocks.

Pipe sizes which do not correspond to NPS measurements should be included in the "Other Pipe Sizes Not Listed" columns. Include both the pipe size and the corresponding mileage.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

PART I – MILES OF PIPE BY DECADE INSTALLED

Report the miles of pipe by decade installed. Make an entry in each block including zero (0) when appropriate. Some companies may have pipe for which installation records may not exist. When the decade of construction is unknown, enter estimates of the totals of such mileage in the "Pre-20 or Unknown" section of Part I.

The sum total of pipeline mileage reported in Part I should match the totals reported in Parts H and J.

PART J – MILES OF PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

Report the total miles of steel pipe by hoop stress (as percent of SMYS) and pipe material type (steel or non-steel) for pipe onshore (in non-rural and rural areas where indicated) and offshore.

Report the total miles of non-steel pipe operating above 125 psig and at or below 125 psig, differentiated for location as for steel pipe.

Report data only for pipelines regulated by PHMSA (and their certified State agencies) and not those which are regulated by other federal or state authorities, including those rural, low stress pipeline segments subject only to Subpart B of 49 CFR 195.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

PART K – MILES OF REGULATED GATHERING LINES

This Part only applies to the Commodity Group "crude oil" and to those portions of gathering lines that are regulated by PHMSA. Report the total mileage of these lines only.

Gathering lines are defined in §195.2 as "A pipeline 219.1mm (8-5/8 inch) or less nominal outside diameter that transports petroleum from a production facility."

Regulated rural gathering lines are defined in §195.11(a) and should be reported in this Part.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

PART L – TOTAL SEGMENT MILES THAT COULD AFFECT HCAs

By Type of HCA. Report the miles of pipeline that the operator has determined could affect an HCA of each designated type. Operators should note that a single segment of pipeline may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Accordingly, the total of the miles reported in these columns may add to more than the total mileage that could affect an HCA reported in Part B.

Not By Type. Report the total miles of pipeline that the operator has determined could affect an HCA. For this number, Operators should NOT double-count mileage for a single segment of pipeline that may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Accordingly, the total of the miles reported in this column, when added for each State, should equal the total mileage that could affect an HCA reported in Part B.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

PART M – BREAKOUT TANKS

List the number of tanks by capacity and by Commodity Group, including any Commodity Groups which are not the predominantly transported Commodity Group within this Report. The Commodity Groups listed here in Part M should match those listed in Part C. Operators are required to submit all breakout tank information in their Annual Report. The operator can also submit their breakout tank information to NPMS, but breakout tanks must always be reported in their Annual Report.

For the designated Commodity Group, complete Part N one time for all of the pipelines and/or pipeline facilities included within this OPID. Complete Part O one time for all the pipelines and/or pipeline facilities covered under this Commodity Group and OPID if any portion(s) of the pipelines and/or pipeline facilities are included in an IM Program subject to §195.452 as indicated in Part A, Question 6.

PART N – PREPARER SIGNATURE

The Preparer is the person who compiled the information and prepared the responses to the Report. Enter the Preparer's name and title, and e-mail address if the Preparer has one, as well as the phone and fax numbers used by the Preparer.

PART O – CERTIFYING SIGNATURE

CERTIFYING SIGNATURE must be a senior executive officer of the operator. The Pipeline Inspection, Protection, Enforcement and Safety Act (signed in December 2006) requires pipeline operators to have a senior executive officer of the company sign and certify annual pipeline Integrity Management Program (IMP) performance reports (Parts B, F, G, and L of this Report). By this signature, the senior executive officer is certifying that he or she has (1) reviewed the Report and (2) to the best of his or her knowledge, believes the Report is true and complete.

Senior Executive Officer is the person who is certifying the information on Parts B, F, G, and L as required by 49 U.S.C. 60109(f).

The name and title of the senior executive officer certifying the Report should be entered in the appropriate blanks on this section of the Report. The name of the senior executive officer certifying the Report should also be entered in the signature block on the Report. Operators should keep in mind that entering the senior executive officer's name onto the electronic Report is equivalent to a paper submission and has the same legal authenticity and requirements.

GENERAL INSTRUCTIONS

All section references are to Title 49 of the Code of Federal Regulations (49 CFR). The OPID Assignment Request is used by operators to request an Operator Identification Number (OPID) from PHMSA for gas and hazardous liquid pipelines or pipeline facilities, or for liquefied natural gas (LNG) facilities. The information contained within this OPID Assignment Request will also be used for validating information on existing OPIDs.

Each operator of a gas or hazardous liquid pipeline, or pipeline facility, or LNG plant or LNG facility not already assigned an OPID from PHMSA is required to obtain an OPID in accordance with §191.22(a) or §195.64(a). Operators requesting a new OPID from PHMSA are also required to obtain one in accordance with §191.22(a) or §195.64(a). If already assigned an OPID by PHMSA, each operator must validate this OPID in accordance with §191.22(b) or §195.64(b).

Except as specified in this paragraph, the OPID assignment requirements do not apply to an operator of either a petroleum gas system that serves fewer than 100 customers from a single source or master meter systems (11/10/11;76 FR 70217). Operators of petroleum gas systems, serving fewer than 100 customers that are required to file incident reports in accordance with Part 191, are to contact the PHMSA Information Resources Manager at (202) 366-8075 to obtain an OPID.

Operators must use their PHMSA-assigned OPID for all Part 191 and 195 reporting requirements in accordance with §191.22(d) or §195.64(d). If an Operator has a single OPID, then all of its reporting to PHMSA for regulated pipelines, pipeline facilities, and/or LNG facilities will use the one OPID Number assigned to the Operator for those assets. If an Operator has multiple OPIDs, then the Operator must use only the OPID assigned to the specific and unique pipeline segments, pipeline facilities, and/or LNG facilities covered by that OPID, and use that OPID consistently for those assets for all of its reporting to PHMSA. The term "operator" is defined in §§191.3, 192.3, 193.2007, and 195.2.

If you need copies of the Form PHMSA F 1000.1 and/or instructions they can be found on the Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking the Library hyperlink and then selecting the Forms link under the "Mini-Menu" on the right side of the page. If you have questions about this form or these instructions, contact the PHMSA Information Resources Manager at (202) 366-8075.

OMB Control No. 2137-0627
Expiration Date: 12/31/2014

REPORTING METHODS

Requests for an OPID must be made online unless an alternate method is approved. (See Alternate Reporting Methods below.) Use the following procedure:

1. Navigate to the PHMSA Portal main page, https://portal.phmsa.dot.gov/pipeline,
2. Click **Request Operator ID** link located below the login box.
3. Enter your email address, last name, and phone number, and then click **Continue.** This information will allow you to access any draft or submitted requests that were made using the new OPID Assignment Request form.
4. Click on **Create New Application** and complete the form, using these instructions as guidance.
5. To save intermediate work without formally submitting the OPID Assignment Request to PHMSA, click **Save**.
6. Click **Submit** when you have completed the form and are ready to initiate formal submission of your request to PHMSA.
7. A confirmation page will appear indicating that your request has been submitted, and a link will appear that will allow you to save a PDF copy of your request.
8. PHMSA will then notify you in a separate communication regarding the granting or denial of your request. In some cases, PHMSA may contact you by phone or email with questions they may have prior to granting your request.

Alternate Reporting Methods

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternate reporting method. Operators must follow the requirements in §191.7(d) or **§**195.58(d) to request an alternate reporting method and must comply with any conditions imposed as part of PHMSA's approval of an alternate reporting method.

SPECIAL INSTRUCTIONS

Make an entry in each block which is applicable. Estimate data only if necessary. Avoid entering any data as **UNKNOWN or 0 (zero)** except where zero is appropriate to indicate that there were no instances or amounts of the attribute being reported.

Do not report pipeline miles in feet. When reporting mileages that are less than 10 miles or when reporting portions of a mile, convert feet into a decimal notation (e.g. 2,640 feet = .5 miles) and report mileage using decimals rounded to the nearest tenth of a mile. Operators may round all mileages that are greater than 10 miles to the nearest mile. Do not use fractions.

STEP 1 – ENTER BASIC REPORT INFORMATION

Enter the date on which this OPID Assignment Request is submitted. For online Requests, the submission date will automatically be entered. Complete all 7 questions of STEP 1 before continuing to STEP 2.

1. Are the pipelines and/or facilities covered by this OPID Assignment Request subject to regulation under all or any part of 49 CFR Parts 191, 192, 193, 194, and/or 195?

The applicant should review the pipeline safety regulations to determine whether or not its pipelines and/or facilities are subject to regulation under the pipeline safety regulations. Refer to §§191.1, 192.1, 193.2001, 194.3, and 195.0 which describe the scope of applicability of each Part of the regulations.

Check the "Yes" box if any of the pipelines and/or facilities covered by this OPID Assignment Request are subject to the pipeline safety regulations. Continue to STEP 1, Question 2.

Check the "No" box if the pipelines and/or facilities covered by this OPID Assignment Request are not subject to the pipeline safety regulations. In this case, an OPID is not required and the OPID Assignment Request need not be submitted.

2. Are the pipelines and/or facilities covered by this OPID Assignment Request:

Indicate whether the pipelines and/or facilities covered by this OPID Assignment Request are newly constructed (i.e., new facilities that have never been operated under an existing OPID) or existing pipelines and/or facilities.

For newly constructed pipelines and/or facilities, provide the approximate start date of construction and the anticipated date of operational startup. PHMSA will use this information to plan inspections during construction and startup.

For existing pipelines and/or facilities, indicate whether they were previously operated under another OPID. Existing pipelines and/or facilities may not have been operated under a prior OPID due to an inadvertent oversight or because they are being converted to service subject to the pipeline safety regulations under §192.14 or §195.5. Operators should respond Yes to Question 2a if the pipelines and/or facilities have previously been operated under an OPID even if that OPID is still being used for other pipelines and/or facilities (e.g., an Operator acquired only part of a pipeline system operating under an existing OPID, and now wishes to obtain a new OPID for those portions acquired). When existing pipelines and/or facilities were previously operated under another OPID and the previous OPID Number is known, provide the OPID Number and name of the previous Operator in Question 2b. For online Requests, the previous Operator's name will automatically be entered based on the OPID entered. If the name that appears is not correct or does not coincide with the OPID Number, contact the PHMSA Information Resources Manager at (202) 366-8075.

3. Operator name for this OPID Assignment Request

Enter the Operator name by which the applicant wants to be identified within PHMSA records for the OPID being requested.

4. Operator Headquarters address

Enter the address of the Operator's corporate headquarters.

5. Name of Operator contact for this OPID Assignment Request

Enter the name of the individual whom PHMSA should contact should they have questions about this OPID Assignment Request.

6. Phone number of Operator contact for this OPID Assignment Request

Enter the phone number by which the Operator contact for this OPID Assignment Request should be reached.

7. Is this Operator a wholly owned subsidiary of another company?

Indicate here whether the Operator submitting this OPID Assignment Request is a subsidiary of another company. If yes, provide the parent company's name.

STEP 2 – ENTER DESCRIPTION OF PIPELINES AND/OR FACILITIES

1. The pipelines and/or facilities covered by this OPID Assignment Request are associated with the following types of facilities and transport the following types of commodities: ***(select all that apply)***

Check the appropriate box or boxes to indicate the type(s) of pipelines and/or facilities for which this OPID Assignment Request applies. Once the type of pipelines and/or facilities is selected, the Operator is also then to select the commodities involved which are associated with the type(s) of pipelines and/or facilities selected. The following definitions are provided to assist operators in making their selections.

Synthetic Gas - examples include landfill gas, biogas, and manufactured gas based on naphtha.

Gas Gathering (Regulated) pipelines are determined in accordance with the requirements of §192.8.

Crude Oil - unrefined oil consisting mainly of hydrocarbons.

Refined and/or Petroleum Product (non-HVL) – flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds. Examples include motor gasoline, diesel fuel, fuel oil, aviation gasoline, jet fuel, kerosene, acetone, benzene, MTBE, naphtha, or other non-HVL petroleum products. In these instructions, "petroleum products" is meant to be synonymous with "refined products".

Highly Volatile Liquids (HVLs) – a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa at 37.8º C (100º F). Examples include ethane, ethylene, propane, propylene, butylene, and anhydrous ammonia (NH_3).

Carbon Dioxide (CO_2) – a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Fuel Grade Ethanol – a clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. This commodity is to be selected only if the pipeline and/or facility is used predominantly to transport ethanol which has NOT been blended with petroleum products. This commodity is sometimes also known as "neat" ethanol.

Regulated Hazardous Liquid Gathering pipelines are as defined in Part 195.

2. Will any single pipeline or pipeline facility included in this OPID Assignment Request be subject to BOTH 49 CFR Part 192 AND 49 CFR Part 195 due to the planned transportation of commodities which are subject to both Parts?

Check the "Yes" box if any single pipeline or pipeline facility will transport both natural or other gas subject to 49 CFR Part 192 and a hazardous liquid or carbon dioxide subject to 49 CFR Part 195; otherwise, check "No".

3. For the top level pipeline and/or facility type selected in STEP 2, Question 1, complete the following:

Miles under 10 should be reported to the nearest tenth mile; miles over 10 may be rounded to the nearest mile.

For LNG Plant(s) or Facility(ies), complete the questions for each set of Interstate and Intrastate assets. Plants/Facilities under a single OPID may be either interstate, intrastate, or both. Check the appropriate box or boxes to indicate whether the plants/facilities are interstate or intrastate or both, and complete the additional questions associated with each. Indicate all states in which LNG Plants/Facilities are located. Also list the counties in each state in which the plants/facilities included in this OPID Assignment Request are located.

For Gas Distribution, select the type(s) of operator involved, indicating the states where the gas distribution pipelines and/or facilities are physically located for each type of operator. Indicate the total amount of regulated miles of Mains included in this OPID Assignment Request.

For Gas Gathering, select whether the pipelines and/or facilities are onshore, offshore, or both, and for each indicate the total miles of regulated gathering pipelines as well as the states - and, where applicable, the OCS area(s) - where the gas gathering pipelines and/or facilities are physically located.

For Gas Transmission or Hazardous Liquid, the series of questions under STEP 2, Question 3 should be completed *separately* for each of these facility types selected. In other words, if the Request covers both Gas Transmission *and* Hazardous Liquid facilities, then STEP 2, Questions 3a - 3j will need to be completed two separate times – once for each of these two facility types. Complete the questions for each set of Interstate and Intrastate assets. Pipelines under a single OPID may be either interstate, intrastate, or both. Check the appropriate box or boxes to indicate whether the pipelines and/or facilities are interstate or intrastate or both, and complete the additional questions associated with each. Indicate whether the pipelines and/or facilities are located onshore, offshore, or both, providing the approximate number of regulated pipeline miles as well as the states and counties - and, where applicable, the OCS area(s) - where the pipelines and/or facilities are physically located, including a separate set of questions for regulated hazardous liquid gathering lines.

For gas transmission pipelines, Interstate and Intrastate are defined by statute as:

> ***Interstate*** *gas pipeline* means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (15 U.S.C. 717 et seq.).
>
> ***Intrastate*** *gas pipeline* means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas within a state and is not subject to the jurisdiction of FERC under the Natural Gas Act (15 U.S.C. 717 et seq.).

For hazardous liquid pipelines, Interstate and Intrastate pipelines are defined in §195.2 as:

> ***Interstate*** *hazardous liquid pipeline* means a hazardous liquid pipeline facility or that part of a hazardous liquid pipeline facility that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.
>
> ***Intrastate*** *hazardous liquid pipeline* means a hazardous liquid pipeline facility or that part of a hazardous liquid pipeline facility to which Part 195 applies that is not an interstate pipeline.
>
> Appendix A to 49 CFR 195 contains PHMSA's Statement of Policy and Interpretation on the delineation between interstate and intrastate hazardous liquid pipelines, and provides additional guidance.

Offshore is defined in §192.3 and **§**195.2 as "beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters." Pipe that is located in areas not meeting the definition of offshore is considered ***Onshore***.

4. Provide a brief and general description of the pipelines and/or facilities covered by this OPID Assignment Request:

Operators are to provide a general description of the nature and location of the pipelines and/or facilities covered by this OPID Assignment Request. Operators are to describe each second level selection from STEP 2, Question 1 separately. For example, if a Gas Distribution Operator checked both Natural Gas and Propane Gas, they should provide a brief and general description of each type of system separately. Similarly, if an Operator checked both Gas Transmission and Gas Gathering, they should provide a brief and general description of each type of system separately.

Operators requesting an OPID on-line will be afforded the opportunity to upload files including general overview maps, schematics, or drawings. Files can be in PDF format. Operators making requests by alternate methods per §191.7(d) or **§**195.64(d) are encouraged to attach copies of general overview maps, schematics, or drawings identifying the facilities.

The following are examples of the minimum descriptions to be provided by operators. For hazardous liquid, gas transmission, offshore, and gathering pipelines and facilities, accompanying maps, schematics, or drawings are preferred in lieu of the additional detail that would be needed in this description were maps, schematics, or drawings not supplied by the operator with this submission.

Example for Gas Distribution Systems

This OPID covers a natural gas distribution system in the Navasota, Texas, area. The system includes 10 miles of transmission lines, 100 miles of mains, and over 20,000 service lines.

Example for LPG Distribution Systems

This OPID covers five (5) LPG distribution systems serving over 100 customers each in Florida. These LPG systems serve customers in Tampa, Tallahassee, and West Palm Beach.

Examples for Gas Transmission Pipeline Systems

The Kanpack Pipeline Company has acquired operation of part of the Flint Hills Pipeline system in Kansas. The pipeline system comprises 642 miles of transmission lines of various sizes, three (3) compressor stations, and a storage field. The system consists of three (3) 24”-30” pipelines in a common ROW between Wamego and Wichita, Kansas, with numerous laterals of various sizes to cities and towns along the main lines, and a storage field near Wilsey, KS. Maps of the system are provided rather than a detailed description due to the numerous laterals and the storage field.

The PT pipeline is a 660-mile long, 26” natural gas pipeline that transports approx. 800,000 SCFPD. It originates in Baton Rouge, Louisiana, and terminates near Atlanta, Georgia, after passing near Tallahassee, Florida. It connects to pipelines operated by others at our Garby Station in Walton County, Florida, and our Linkwood Station in Colquitt County, Georgia. There are 12 intermediate compressor stations. Maps depicting the location and general routing of this pipeline and its associated facilities are included.

Example for Hazardous Liquid Pipeline Systems (also an example when multiple systems are involved)

This OPID covers two (2) hazardous liquid pipeline systems. Maps depicting the location and general routing of each of these pipelines and their associated facilities are included.

The Big Sky pipeline is a 453-mile long, 26" crude oil pipeline that transports approximately 250,000 BPD. It originates in Johnson County, Wyoming, and terminates in Cushing, Oklahoma, where it connects with several pipelines operated by others at our Cushing Tank Farm (10 tanks with a total capacity of 1.2 million bbls). There are 10 intermediate pump stations with one (1) intermediate breakout tank farm at our Fischer Station in Fort Collins, Colorado (two (2) tanks with a total capacity 300,000 bbls).

The Catherine Falls pipeline is a 250-mile long, 16" refined products pipeline that transports approx. 150,000 BPD. It originates at the Mud Island Refinery in Wood River, Illinois, and terminates in Columbus, Ohio, at our Pender Terminal (20 tanks with a total capacity of 1.0 million bbls). There are six (6) intermediate pump stations and three (3) delivery laterals along this pipeline route: a 10-mile 10" lateral connecting in Effingham County, Illinois; a 2-mile 8" lateral connecting in Marion County, Indiana; and a 4-mile 8" lateral connecting in Montgomery County, Ohio. There are no connecting pipelines at Pender Terminal as all products are delivered via truck racks.

<u>Example for an Offshore Pipeline System</u>

This OPID covers an offshore pipeline system in the Gulf of Mexico. A map depicting the location and general routing of this pipeline system and its connecting platforms and associated facilities are included. Total throughput is approx. 140,000 BPD. The pipeline system consists of 120 total miles of 16", 20", and 26" pipelines connecting 3 offshore production platforms and terminating at our Rogers Tank Farm in Littleton, Louisiana (four (4) tanks with a total capacity of 600,000 bbls). This pipeline system also includes four DOT-regulated platforms.

<u>Example for a Gathering Pipeline System (Gas or Hazardous Liquid)</u>

This OPID covers three (3) sour crude oil gathering systems located in central and south-central Kentucky which transport a total of 40,000 BPD. Maps depicting the location and general routing of each of these gathering systems and their associated facilities are included. The gathering systems total 88 miles of various sized pipe ranging from 4" in diameter to 10".

STEP 3 – PROVIDE PHMSA-REQUIRED PIPELINE SAFETY PROGRAM OR LNG SAFETY PROGRAM INFORMATION

This STEP 3 is to be completed once for each top level facility type selected in STEP 2, Question 1. In other words, if the Request covers both Gas Transmission *and* Hazardous Liquid facilities, then this STEP 3 will need to be completed two separate times – once for each of these two facility types.

Pipeline safety regulations require operators to prepare and implement a number of safety programs, depending on the type of pipelines and/or facilities they operate. These include:

- Anti-Drug Plan and Alcohol Misuse Plan (§§199.101, 199.202)
- Procedure Manual for Operations, Maintenance, and Emergencies (§§192.605,

192.615, 195.402)

- Damage Prevention Program (§§192.614, 195.442)
- Public Awareness/Education Program (§§192.616, 195.440)
- Control Room Management Procedures (§§192.631, 195.446)
- Operator Qualification Program (§§192.805, 195.505)
- Integrity Management Program (§§192.907, 192.1005, 195.452)
- Response Plan for Onshore Oil Pipelines (or Alternative State Plan) (§§194.101)
- LNG Plans and Procedures (§§193.2017)

Most often, operators prepare separate and independent safety programs for the pipelines and/or facilities covered by their assigned OPID. In some instances, though (e.g., usually involving larger operators with multi-state and multi-system operations), one or more of these PHMSA-required safety programs cover – or are common to - multiple OPIDs. (These common safety programs are sometimes referred to as “umbrella” safety programs.) When a common (or “umbrella”) PHMSA-required pipeline safety program(s) or LNG safety program(s) exists which covers more than a single OPID, the Operator assigned those OPIDs is required to report in this section which one of the various OPIDs is “primary” for each PHMSA-required pipeline safety program or LNG safety program for the purposes of PHMSA inspections and Operator Registry Reporting. Generally this is the OPID associated with the parent company or OPID associated with the operating entity responsible for managing implementation of the safety program, and usually represents the office which should be contacted and referred to when PHMSA or a state exercising jurisdiction intends to inspect that safety program. (For example, if the pipelines covered by an OPID Assignment Request for OPID 67890 are part of an IM Program that is administered by the operator under its existing OPID 12345, then the primary OPID would be 12345.) The designation of which of multiple OPIDs is “Primary” is at the discretion of the operator, but it is important that – once a particular OPID is selected as “Primary” – the operator continue to list this same OPID as “Primary” in future notifications concerning the safety program in question.

1. Are the pipelines and/or facilities covered by this OPID Assignment Request included with other OPIDs for the purposes of compliance with one or more PHMSA-required pipeline safety program(s) or LNG safety program(s)? *(select only one)*

Check the “Not known at this time” box if the Operator has yet to decide whether their PHMSA-required safety programs for the pipelines and/or facilities covered by this OPID Assignment Request will be separate and independent or whether one or more will be included in a common safety program that includes other OPIDs. If this box is checked, the Operator is required to submit an Operator Registry Notification within 60 days after this information is known. It should be noted that many of these programs are required to be in place before initial operations of the pipelines and/or facilities commence.

Check the “No” box if the pipelines and/or facilities covered by this OPID Assignment Request are covered by their own independent programs for all of the applicable PHMSA-required safety programs listed above.

Check the “Yes” box if the pipelines and/or facilities covered by this OPID Assignment Request are included in one or more common PHMSA-required safety programs. Check the box(es) for the program(s) that are common to other OPIDs and indicate, for each, the OPID the Operator considers to have "primary" responsibility for that safety program.

Correctly establishing the primary OPID associated with each PHMSA-required safety program is very important as it will allow PHMSA to accurately assign compliance performance and incident history to the proper entity. This information, along with Operator Registry Notifications, ensures that PHMSA assigns this performance correctly over the appropriate time periods as well.

STEP 4 – PROVIDE CONTACT INFORMATION

Provide the requested information for the various Operator personnel or locations PHMSA may need to contact in various situations.

For Question 1, this is the individual who oversees overall pipeline safety compliance for the operator and typically is the principal contact for PHMSA to discuss regulatory issues. This would include individuals with such titles as Manager of Compliance, Regulatory Compliance Officer, DOT Compliance Supervisor, Pipeline Safety Manager, Community Safety Manager, etc.

Where the Operator's contact for inspection scheduling is the same as the person responsible for overseeing compliance with pipeline safety regulations as reported in Question 1, leave Question 2 blank.

Where pipelines and/or facilities covered by this OPID Assignment Request are located in multiple PHMSA Regions, and where the Operator's contact for inspection scheduling is NOT the same as the person listed in Question 1, provide an inspection scheduling contact for each PHMSA Region in Question 2. (See the Pipeline Safety Community web site, http://www.phmsa.dot.gov/pipeline/about/org, for a depiction of the states in each PHMSA Region).

Where no control center exists, leave Question 5 blank.

Complete the contact information for Questions 7, 8, and 9 when those contacts are applicable for the pipelines and/or facilities covered under this OPID Assignment Request.

[End of Instructions]

PIPELINE MAINTENANCE AND SURVEILLANCE FORM 3.01B

NOTE: FILL OUT THIS REPORT FOR EACH EXPOSURE OF PIPELINE REGARDLESS OF THE CAUSE

COMPANY:	OPERATING LOCATION:	NAME OF LINE:	LINE NO:	DATE OF REPORT MO DAY YR

DRAWING NO:	LOCATION OR STATION PLUS LIMITS	PIPELINE SYSTEM ☐ GAS ☐ LIQ	CLASS LOCATION (GAS):	DATE OF INSPECTION MO ____ DAY ____ YR ____

PIPE:	SIZE O.D.	WALL THICKNESS	GRADE/SPECIFICATIONS/SEAM:	DEPTH OF COVER:

PURPOSE OF MAINTENANCE OR SURVEILLANCE:

☐ PIPELINE LEAK ☐ PIPELINE CHANGE OUT ☐ FOREIGN PIPELINE CROSSING
☐ PIPELINE FAILURE ☐ CATHODIC PROTECTION ☐ ABANDONMENT
☐ TAP ☐ CASING ☐ OTHER:

PIPELINE MAINTENANCE: PROCEDURES 8.02 AND 9.01

☐ NO REPAIR OR REPLACEMENT NEEDED, AS OF DATE ____________ ☐ ACTION REQUIRED

1 REPLACED SECTION: SIZE WALL
FROM: ______ TO: ______ O.D. ________ THICKNESS ________ GRADE ________ SPEC. ______ SEAM ______
a) Replacement Section Test Pressure ________ for ______ hrs. Date ________ ☐ Test Chart Attached
b) Field Girth Welds Nondestructively Tested? ☐ No ☐ Yes What method used? ________ %.
c) For Pipelines Parallel to Overhead Electric Transmission Lines, was electric conductor Bonded to Pipeline? ☐ No ☐ Yes

2 REPAIRED SECTION: ☐ TEMPORARY ☐ PERMANENT
a) Method of Repair ____________
b) Pressure Reduced During Repair? ☐ No ☐ Yes Pressure During Repair ________
c) Was Gas Leaking During Repair? ☐ No ☐ Yes Describe ________
d) Welding Nondestructively Tested? ☐ No ☐ Yes What Method Used? ________

INTERNAL CONDITION OF PIPELINE: PROCEDURES: Procedures 6.02 & 6.04

A. INTERNAL CORROSION DISCOVERED? ☐ No ☐ Yes Describe ________
B. METHOD OF INTERNAL CORROSION CONTROL IN EFFECT: ☐ None ☐ Chemical Treatment ☐ Coupons ☐ Other ______

EXTERNAL CONDITION OF PIPELINE: PROCEDURES 6.01, 6.03 & 6.04

A. CATHODIC PROTECTION POTENTIAL OF EXCAVATED EXPOSED PIPE VOLTS ______
B. CONDITION OF COATING: ☐ Satisfactory ☐ Disbonded ☐ Deteriorated ☐ Scraped ☐ SCC ______
C. INDICATED CATHODIC PROTECTION POTENTIAL FROM PREVIOUS SURVEY ______ VOLTS DATE ______

HOT TAP REPORT: PROCEDURES 9.05

A. FOR: ______ SIZE: ________ LOCATION: ☐ TOP ☐ SIDE
B. MATERIAL ☐ FULL ENCIRCLEMENT SADDLE ☐ WELD TEE SIZE: ______ GRADE: ______ VALVE: ______ MAKE ______ TYPE
NIPPLE: LENGTH ______ W.T. ______ GRADE ______ INSULATION ______ ☐ No ☐ Yes
C. ASSEMBLY TEST: ☐ HYDRO TEST ______ (Test Chart Attached) ☐ PNEUMATIC TEST ______
OTHER NONDESTRUCTIVE TEST: METHOD ________ HEADER THICKNESS ________

FOREIGN PIPELINE CROSSING: PROCEDURE 3.05

A. COMPANY: ________ LINE SIZE ________ CLEARANCE IN INCHES ______ ☐ ABOVE ☐ BELOW
B. PIPE: ☐ STEEL ☐ OTHER
C. COATING: ☐ COATED ☐ BARE
D. APPROX. ANGLE OF CROSSING ________ PRODUCT TRANSPORTED ________

REMARKS:

____
____
____

Draw Foreign Line Crossing Company line or hot tap and arrow indicating North.

Company Line

SIGNATURES:
COMPLETED BY: ________________
SUPERVISOR: ________________

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BREAKOUT TANK INSPECTION AND TESTING FORM

FORM 4.02A

LOCATION: ____________________

SYSTEM: ____________________

DATE: ____________________
MO/DAY/YR

SIGNATURES:

COMPLETED BY: ____________________

SUPERVISOR: ____________________

☐ ATMOSPHERIC TANK
☐ PRESSURE TANK, MAOP=___________ PSIG

1) ROOF

☐ LIGHT SURFACE RUST, NOT MEASURABLE

☐ MEDIUM SURFACE RUST, MEASURABLE, BUT NOT DETRIMENTAL ULTRASONIC TEST READING:_______________

☐ HEAVY OBVIOUS PITTING ULTRASONIC TEST READING:
COMMENTS/ACTION(S) TAKEN: ____________________
____

☐ FLOATING ROOF SEALS SERVICABLE ☐ YES ☐ NO
COMMENTS: ____________________

2) BOTTOM

☐ LIGHT SURFACE RUST, NOT MEASURABLE

☐ MEDIUM SURFACE RUST, MEASURABLE, BUT NOT DETRIMENTAL ULTRASONIC TEST READING:__________

☐ HEAVY OBVIOUS PITTING ULTRASONIC TEST READING:_____________
COMMENTS/ACTION(S) TAKEN: ____________________
____

☐ BOTTOM/FOUNDATION INTERFACE SIGNS OF LEAKAGE
☐ " " " LIGHT RUST
☐ " " " MEDIUM RUST
☐ " " " HEAVY RUST

3) SIDES

☐ LIGHT SURFACE RUST, NOT MEASURABLE

☐ MEDIUM SURFACE RUST, MEASURABLE, BUT NOT DETRIMENTAL ULTRASONIC TEST READING: _____________

☐ HEAVY OBVIOUS PITTING ULTRASONIC TEST READING:_____________
COMMENTS/ACTION(S) TAKEN: ____________________
____

TOC

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 195.401	Date Revised: August 2013

CONTINUING SURVEILLANCE REPORT FOR YEAR 2013

Initial Report ☐ **Supplemental Report** ☐

Pipeline System Reviewed: Action #1 – Record Review:

☐ ____________________________
☐ ____________________________
☐ ____________________________

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			**Description of Record or Report & Regs [195, Subpart B]:**
#	**Sat**	**Unsat**	**NA**	***Incidents, Annual Reports, Safety Related Conditions***
1	☐	☐	☐	Have there been any events that would require telephone notice of certain incidents? If yes, is the record of the telephone notice complete?
2	☐	☐	☐	Have there been any events that would require written incident report? If yes, is the written record complete?
3	☐	☐	☐	Have there been any events that would require written supplemental incident report? If yes, is the written record complete?
4	☐	☐	☐	Was PHMSA annual report (PHMSA form 7100.2-1) filed electronically by March 15th? Has PHMSA made any requests for additional information or amendments to the annual report?)
5	☐	☐	☐	Have there been any events that would require a safety related condition report? If yes, is the SRC report complete?
6	☐	☐	☐	Have there been any acquisitions of new jurisdictional pipelines? If yes, was PHMSA notified?
7	☐	☐	☐	Has there been any new construction of jurisdictional pipelines? If yes, was PHMSA notified?

CONTINUING SURVEILLANCE REPORT (cont.)

	Condition:			**Description of Record or Report & Regs:**
#	**Sat**	**Unsat**	**NA**	***Corrosion Control: Subpart H [195.551-589]***
8	☐	☐	☐	Have there been any external exposed pipe events? If yes, was an exposed pipe report completed. Is the exposed pipe report complete?
9	☐	☐	☐	What is the condition of the external coating? Are any repairs or remediation required?
10	☐	☐	☐	Was the annual CP survey conducted once per calendar year, not to exceed 15 months? Are there any repairs or remediation required?
11	☐	☐	☐	Were all bi-monthly rectifier inspections completed every two months, not to exceed 2 1/2 months? Are the there any repairs or remediation required?
12	☐	☐	☐	Were all bi-monthly critical bond inspections completed every two months, not to exceed 2 1/2 months? Are the there any repairs or remediation required?
13	☐	☐	☐	Are there any outstanding remedial actions?
14	☐	☐	☐	Has a close internal survey been conducted, if applicable? Are there any remedial actions?
15	☐	☐	☐	Is electrical isolation, insulating devices, and ground fault protection adequate? Are there any remedial actions?
16	☐	☐	☐	Are CP test stations in good condition? Are any repairs or labeling needed?
17	☐	☐	☐	Are CP test stations leads in good condition? Are any repairs or labeling needed?
18	☐	☐	☐	Have tests for interference currents been conducted? Are there any remedial actions?
19	☐	☐	☐	Has a gas sample been taken and analyzed by a lab for corrosive properties?
20	☐	☐	☐	Were the lab results of the gas sample reviewed by a corrosion engineer?
21	☐	☐	☐	Have there been any internal exposed pipe events? If yes, was an exposed pipe report completed. Is the exposed pipe report complete?
22	☐	☐	☐	For new or replaced segments of the pipeline, was the new construction and/or replacement designed to minimize internal corrosion? There should engineering design spec or engineering review document.
23	☐	☐	☐	If corrosive gas is transported, have internal corrosion control monitoring been conducted 6x/year, not to exceed 2 1/2 months? Note, monitoring could be coupons, corrosion inhibitor, other.
24	☐	☐	☐	Have atmospheric corrosion inspections been conducted on required frequency? Frequency for offhore is once per calendar year, not to exceed 15 months. Frequency for onshore is once every 3 years, not to exceed 39 months.
25	☐	☐	☐	Have all CP remedial measures been addressed or part of an ongoing action plan?
26	☐	☐	☐	Has a direct assessment been conducted? If yes, were the requirements of 192.490 followed?
27	☐	☐	☐	Are CP inspections records maintained for 5 years minimum? (5 years)
28	☐	☐	☐	Are the following CP records maintained for the life of the pipeline? (CP Survey, CIS, Internal Inspection, CP remedial actions)

CONTINUING SURVEILLANCE REPORT (cont.)

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			Description of Record or Report & Regulation:
#	**Sat**	**Unsat**	**NA**	***Operations and Maintenance: Subpart F [195.400-446]***
29	☐	☐	☐	Has there been an annual review of O&M procedures that was conducted once per calendar year, not to exceed 15 months?
30	☐	☐	☐	Has there been an annual review of the PSOM procedures that was conducted once per calendar year, not to exceed 15 months?
31	☐	☐	☐	Has there been an annual review of the pipeline emergency plan that was conducted once per calendar year, not to exceed 15 months?
32	☐	☐	☐	Has there been an annual review of work performed by operator. The intent of this requirement is to audit the procedure while watching someone conduct the task selected.
33	☐	☐	☐	Has there been an abnormal operations event? If yes, was an abnormal operations investigation conducted and report completed?
34	☐	☐	☐	Has a annual class location survey been conducted. Has there been a change in class location?
35	☐	☐	☐	If there was a change in population around the pipeline? If yes, is a new HCA survey required?
36	☐	☐	☐	Has a continuing surveillance review been conducted annually? Are action items documented?
37	☐	☐	☐	Have damage prevention one call records been maintained
38	☐	☐	☐	Is a list of excavators documented and maintained?
39	☐	☐	☐	Has emergency plan training been conducted annually? Note, this can be accomplished with agency drill, table top drill, class room training, or documentation of actual emergency response event.
40	☐	☐	☐	For actual emergencies or emergency drills, was the response of personnel evaluated?
41	☐	☐	☐	Have government liaison meeting been conducted annually?
42	☐	☐	☐	Have public awareness mailers been sent to excavators annually? (1x/yr)
43	☐	☐	☐	Have public awareness mailers been sent to emergency officials annually? (1x/yr)
44	☐	☐	☐	Have public awareness mailers been sent to public officials annually? (1x/3yr)
45	☐	☐	☐	Have public awareness mailers been sent to the affected public 1x/2years? (1x/2yr)
46	☐	☐	☐	Have public awareness mailers been sent to the affected public 1x/year for pipeline with sour gas? (1x/yr)
47	☐	☐	☐	Has an effectiveness survey been conducted 1x/4years for excavators? (1x/4yr)
48	☐	☐	☐	Has an effectiveness survey been conducted 1x/4years for emergency officials? (1x/4yr)
49	☐	☐	☐	Has an effectiveness survey been conducted 1x/4years for public officials? (1x/4yr)
50	☐	☐	☐	Has an effectiveness survey been conducted 1x/4years for affected public? (1x4/yr)
51	☐	☐	☐	Has an annual public awareness program self-assessment and evaluation been conducted including PA team charter, PA measures, and PA enhancements?
52	☐	☐	☐	Has there been a pipeline or pipeline facility failure? If yes, was a complete failure investigation conducted including root cause determination and preventive measures?
53	☐	☐	☐	Has MOP been determined using one of the most limiting factors in 195.406? (pressure test, pipe material, flange/valve rating, operating history)

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 195.401	Date Revised: August 2013

54	☐	☐	☐	Is the pipeline operating at alternate MOP levels (>72% SMYS)? If yes, were all additional requirements followed?
55	☐	☐	☐	Are periodic odorization test conducted with an instrument?
56	☐	☐	☐	If hot tap was conducted, were the requirements of 192.627 followed?
57	☐	☐	☐	If purging was conducted, were purging procedure requirements followed?

CONTINUING SURVEILLANCE REPORT (cont.)

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			Description of Record or Report & Regulation:
#	**Sat**	**Unsat**	**NA**	***Operations and Maintenance: Subpart F [195.400-446]***
58	☐	☐	☐	If unsafe segments were discovered, were they replaced, repaired, or removed from service?
59	☐	☐	☐	Were patrols conducted in timely manner at a frequency determined by class location?
60	☐	☐	☐	Were critical crossings conducted in timely manner at a frequency determined by class location?
61	☐	☐	☐	Were gas leak surveys conducted in timely manner at a frequency determined by class location?
62	☐	☐	☐	Are line markers properly maintained, located at all appropriate locations, and contain the required message on the sign?
63	☐	☐	☐	Are repairs records maintained for the life of the pipeline?
64	☐	☐	☐	Are all O&M records maintained for a minimum of five years?
65	☐	☐	☐	For repairs for >40% SYMS, were all requirements followed?
66	☐	☐	☐	For permanent field repair of imperfections or damage, were all requirements followed?
67	☐	☐	☐	For permanent field repair of welds, were all requirements followed?
68	☐	☐	☐	For permanent field repair of leaks, were all requirements followed?
69	☐	☐	☐	For test of repairs, were all requirements followed?
70	☐	☐	☐	Was any pipeline segment abandoned? If yes, were all requirements followed?
71	☐	☐	☐	Were compressor station reliefs inspected and tested once per calendar year, not to exceed 15 months?
72	☐	☐	☐	Were compressor stations combustibles properly stored?
73	☐	☐	☐	Were compressor station gas detection systems inspected and tested once per calendar year, not to exceed 15 months?
74	☐	☐	☐	Were pressure limiting and regulating systems inspected and tested once per calendar year, not to exceed 15 months? (relief valves, regulators, shut down valves)
75	☐	☐	☐	Pressure Limiting & Regulating Station: Indications of Hi/Low Pressure
76	☐	☐	☐	Has a capacity review been conducted on the pressure limiting devices?
77	☐	☐	☐	Were inspections of emergency valves conducted once per calendar year, not to exceed 15 months?
78	☐	☐	☐	Were inspections of vaults conducted once per calendar year, not to exceed 15 months?
79	☐	☐	☐	When working around gas pipeline segments, were prevention of accidental ignition procedures followed?

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 195.401 **Date Revised: August 2013**

Miscellaneous:

#	Condition:			Description of Record or Report & Regulation:
	Sat	Unsat	NA	***Miscellaneous***
80	☐	☐	☐	Have there been any agency audits, letters, or citations? If yes, are concerns being addressed or completed?
81	☐	☐	☐	If a pressure test was conducted, were all requirements followed
82	☐	☐	☐	If a system uprating was conducted, were all requirements followed?
83	☐	☐	☐	Other (Explain)
84	☐	☐	☐	Other (Explain)
85	☐	☐	☐	Other (Explain)

Comments, action taken, and any changes from last review. Number each answer to correspond to survey question number.

Signature & Date:

Print Name / Title

Pipeline Mgr/Supervisor Signature

Date

PIPELINE INSPECTION REPORT

FORM 5.03A

DATE OF SURVEY: ____________________
MO/DAY/YEAR

AREA COVERED: ____________________

____

MAP REFERENCES: ____________________

____

LEAKAGE INDICATIONS DISCOVERED (DESCRIBE LOCATIONS AND INDICATION, SUCH AS CONDITION OF VEGETATION/SHEEN ON WATER ____________________

____

____

LEAKAGE INDICATIONS REPORTED TO: ____________________

CONSTRUCTION ACTIVITY ALONG ROUTE: ____________________

DESCRIBE ANY UNUSUAL CONDITIONS AT HIGHWAY, BRIDGE, AND R.R. CROSSING FOR UNUSUAL CONDITIONS. OFFSHORE INDICATE LORAN COORDINATES ____________________

____

____

EROSION/SLIPPAGE OR EXPOSURE OF PIPE: ____________________

____

____

____

OTHER FACTORS NOTED WHICH COULD AFFECT SAFETY OF PIPELINE: ____________________

____

____

ACTION TAKEN (REPAIRS, MAINTENANCE OR TESTS RESULTING FROM THIS INSPECTION ETC.):

____

____

PIPELINE MARKERS MISSING/DAMAGED AT: ____________________

COMMENTS: ____________________

____

NO. OF PERSON(S) IN PATROL PARTY: ____________________

METHOD (BOAT, HELICOPTER ETC.): ____________________

SIGNATURE OF PERSON(S) IN PATROL PARTY: ____________________

SIGNATURE OF FOREMAN: ____________________ DATE: ____________
MO/DAY/YR

NAVIGABLE WATERWAY CROSSING INSPECTION FORM

FORM 5.03C

DATE OF SURVEY: ____________________
MO/DAY/YEAR

NAVIGABLE WATERWAY CROSSED UNDER: ____________________

MAP REFERENCES: ____________________

LEAKAGE INDICATIONS DISCOVERED (DESCRIBE LOCATIONS AND INDICATIONS.): ____________________

LEAKAGE INDICATIONS REPORTED TO: ____________________

DESCRIBE ANY UNUSUAL CONDITIONS AT WATERWAY CROSSING. ____________________

EROSION/SLIPPAGE OR EXPOSURE OF PIPE OBSERVED: ____________________

OTHER FACTORS NOTED WHICH COULD AFFECT SAFETY OF PIPELINE: ____________________

ACTION TAKEN (REPAIRS, MAINTENANCE OR TESTS RESULTING FROM THIS INSPECTION ETC.):

____

COMMENTS: ____________________

NO. OF PERSON(S) IN PATROL PARTY: ____________________

SIGNATURE OF PERSON(S) IN PATROL PARTY: ____________________

SIGNATURE OF SUPERVISOR: ____________________ DATE: __________
MO/DAY/YR

TOC

EXTERNAL CORROSION TEST FOR ABOVE GROUND FACILITIES

FORM 6.01A [195.583]

DATE: MO DAY YR

SYSTEM: ______________________

SIGNATURE: ______________________

SIGNATURE OF SUPERVISOR: ______________________

PIPELINE INSPECTION		AREA OF POSSIBLE ACTIVE CORROSION				
FROM	TO	FROM	TO	CONDITION *	ULTRA SONIC READING	COMMENTS
STATION	STATION	STATION	STATION	(0,1,2,OR 3)	READING OR PIT DEPTH GA	

* 0 - NO CORROSION
  1 - LIGHT SURFACE RUST - NOT MEASURABLE
  2 - MEDIUM SURFACE RUST - MEASURABLE, BUT NOT DETRIMENTAL (LESS THAN 10% OF NEW PIPE NOMINAL WALL THICKNESS)
  3 - HEAVY. OBVIOUS PITTING (IN EXCESS OF 10% OF NEW PIPE NOMINAL WALL THICKNESS)

TOC

EVALUATION OF LIQUID ANALYSIS
FORM 6.02B-2

Date of Review: ______________________

Name of person conducting review: (print) ______________________

Name of person conducting review: (signature) ______________________

System/Segment: ______________________

Sample Location: ______________________

#	Component:	Limit:	Lab Analysis Unit of Measure:	Lab Analysis Actual Result:	Acceptable (yes/no)	Comments on any Questionable or Unacceptable Results:
1	Free Liquid Water	NA				
2	Basic Sediment & Water (BS&W)	Normally 3%, or contract limits				
3	Hydrogen Sulfide or Sulfur					
4	Oxygen					
5	CO2					
6	pH					
7	Liquids with Sulfate Reducing Bacteria (SRBs)	ten (10) colonies per milliliter				

SAMPLING METHODS:

BS&W: Use ASTM D 4007 (Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method - Laboratory Procedure) for lab testing.

Oxygen, CO2 and H2S: Test the water removed from the oil utilizing ASTM D888 "Standard Test Methods for Dissolved Oxygen in Water", ASTM D513 "Standard Test Method for Total and Dissolved Carbon Dioxide in Water" and ASTM D4810 "Standard Test Method for Sulfide Ion in Water". If no water is present then no test is conducted.

CONVERSION EQUATIONS

Partial Pressure (psia) = PPM x Line Pressure (psia)/1,000,000
Partial Pressure (psia) = Mole % x Line Pressure (psia)/100
ppm = parts per million 1/1,000,000
ppb = parts per billion 1/1,000,000,000

Cathodic Protection System Record
Form # 6.05A

Reference: 49 CFR 195.573 **Date Revised: Jan 2011**

CATHODIC PROTECTION SYSTEM RECORD

Pipeline System:					Date:
Location:					Dwg. No.
Item #	**Test Station #**	**Test Location Description**	**Test Station GPS (lat. & long.)**	**P/S Readings**	**Comments**
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					

Cathodic Protection System Record
Form # 6.05A

Reference: 49 CFR 195.573	Date Revised: Jan 2011

Signature & Date of CP Tester:

CP Tester Signature

Date

Signature & Date of Pipeline Supervisor:

Pipeline Mgr/Supervisor Signature

Date

Rectifier Readings
Form # 6.07A

Reference: 49 CFR 195.573(c)	**Date Revised: May 2011**

RECTIFER READINGS
Required Frequency: 6x/year not to exceed 2 ½ months

Line Location		Unit Location	Unit Number
Make	Size	Serial Number	Year Installed
Year:			

Date:	**Volts:**	**Amps:**	**Inspect the rectifier and its components for proper operation.**	**Name of Person Performing the Inspection:**
Jan				
Feb				
March				
April				
May				
June				
July				
Aug				
Sept				
Oct				
Nov				
Dec				

Corrosion Control Annual Review
O&M Form #6.10A

Reference: 49 CFR 195.573(c)	Date Revised: August 2013

System or Segment:	
System or Segment Length: (in miles)	
Review Conducted By: (print)	
Review Conducted By: (signature)	
Date or Review:	
Review Period Covered:	

Required Frequency: 1x/year

The corrosion engineer or designee shall complete this yearly report which highlights some pertinent corrosion control activities of the company. See procedure #6.10, District Office Review, for additional information.

Corrosion Control Annual Review
O&M Form #6.10A

Reference: 49 CFR 195.573(c)	Date Revised: August 2013

Annual CP Survey Review:

Line #	Description of Corrosion Activity:	Results and Additional Remedial Corrective Action, if Any:
1.	**Number of CP readings below criteria?**	
2.	**Qualification records in the file for person conducting the annual CP survey?**	
3.	**Number of test stations adequate? And number of test stations installed or repaired?**	
4.	**Test stations entered on CP maps**	
5.	**Number of ground beds installed, improved or abandoned, with the locations and reasons for such activities**	
6.	**Number of foreign line interference tests conducted and their results**	
7.	**CP survey recommendations, if any**	

Corrosion Control Annual Review
O&M Form #6.10A

Reference: 49 CFR 195.573(c)	Date Revised: August 2013

Miscellaneous Corrosion Activities for Review:

Line #	Description of Corrosion Activity:	Results and Additional Remedial Corrective Action, if Any:
1.	Miles of "close interval survey" (CIS) conducted	
2.	Miles of "direct current voltage gradient" (DCVG)	
3.	Number of rectifiers repaired and new rectifiers installed. The location and the reason for such activities.	
4.	Miles of pipelines recoated, and the location and the reason for recoating	
5.	Maintenance painting done on above ground piping and structures, including breakout tanks	
6.	If there have been any external exposed pipe reports? If yes, what are the results?	

Corrosion Control Annual Review
O&M Form #6.10A

Reference: 49 CFR 195.573(c)	**Date Revised: August 2013**

Internal Corrosion Activities for Review:

Line #	Description of Corrosion Activity:	Results and Additional Remedial Corrective Action, if Any:
1.	Has an analysis for corrosive properties been conducted initially, or upon changes in product?	
2.	Does review of the lab analysis indicate corrosive properties?	
3.	If corrosive properties, have the corrosive properties been mitigated? If yes, how are the corrosive properties mitigated? (removal of impurities, chemical injection, coupon monitoring)	
4.	What are the results of chemical injection? Is the person conducting chemical injection qualified under the company OQ plan?	
5.	What are the results of coupon monitoring? Is the person conducting coupon monitoring qualified under the company OQ plan?	
6.	If there have been any internal exposed pipe reports? If yes, what are the results?	

EMERGENCY VALVE INSPECTION REPORT
FORM 7.01A

COMPANY:	OPERATING LOCATION:	DATE: ____ MO-DAY-YR
SYSTEM:	STATION: ☐ Haz. Liq. ☐ Nat. Gas	VALVE I.D.:

VALVE LOCATION

☐ Above Ground	☐ Valve in vault	☐ Under Ground (Buried)
☐ Mainline Block Valve	☐ Branch Block Valve	☐ Bypass
☐ Block Under Relief Valve	☐ Plant Block Valve	☐ Other ____
☐ Blowdown Valve	☐ Upstream	☐ Downstream

VALVE SPECIFICATIONS

Manufacturer:			Type:	Model:	
Size:	Rating:	End Connection:	Screwed:	Flanged:	Welded:
Operator:	☐ Wrench	☐ Hand Wheel	☐ Gear	☐ Operator	

MAINTENANCE PERFORMED

Valve Inspected	☐ YES	☐ NO
Valve Partially Operated	☐ YES	☐ NO
Stem & Gearing Parts Inspected	☐ YES	☐ NO
Stem & Gearing Lubricated	☐ YES	☐ NO
Power Operator Tested	☐ YES	☐ NO
Valve Body Drained	☐ YES	☐ NO
Inspected For Atmospheric Corrosion	☐ YES	☐ NO
Repairs Required	☐ YES	☐ NO
Proper Identification For Blow-Off Locations (GAS)	☐ YES	☐ NO
(Sign Should Indicate "Controlled Blowdown Required Due To Overhead Or Adjacent Facilities")		

VALVE SECURITY

Lock And Chain Required:	☐ YES	☐ NO
Lock And Chain In Place:	☐ YES	☐ NO

REMARKS

DISTRIBUTION:

____

____

____

SUPERVISOR:

____
SIGNATURE

INSPECTED BY:

____
SIGNATURE

TOC

RELIEF VALVE REPORT

FORM 7.02A

COMPANY:	OPERATING LOCATION:	DATE: ______ MO-DAY-YR
SYSTEM:	☐ HAZARDOUS LIQUID ☐ NATURAL GAS	VALVE I.D.:

Reason For Report:	☐ Inspection	☐ Repair	☐ New Installation	☐ Removal
System MAOP or MOP:			Set Pressure:	

Manufacturer:	Type/Model:	Serial #:	Orifice Size:
Inlet: ______	☐ Screwed	☐ Flanged	Rating:
Outlet: ______	☐ Screwed	☐ Flanged	Rating:
Block Valve	Size:	Type:	Locked: ☐ Yes ☐ No
Test Connection:	☐ Yes	☐ No	Vent Line Size:
Rain Cap:	☐ Yes	☐ No	Weep Hole: ☐ Yes ☐ No
Lift Lever:	☐ Yes	☐ No	Relief Valve Installation Braced: ☐ Yes ☐ No

Relief Valve Location:		
☐ Side of Header	☐ Top of Header	☐ Remote

Rated Capacity: ______ gpm or scfm Required Capacity: ______ gpm or scfm Date:

☐ Checked, No Changes

Remarks: ______

Distribution:

______

______

______

______

______

Serviced By: ______

Witnessed By: ______

Supervisor: ______

TOC

REGULATOR REPORT

FORM 7.02B

COMPANY:	OPERATING LOCATION:	DATE: ________ MO-DAY-YR
SYSTEM:	☐ HAZARDOUS LIQUID ☐ NATURAL GAS	VALVE I.D.:

Reason For Report: ☐ Inspection ☐ Repair ☐ New Installation ☐ Removal

REGULATOR

Manufacturer:	Model:	Size:	Serial No.:	Make:	Actuator:	Model:	Pressure On Diaphragm: ☐ Open ☐ Close
TYPE INNER VALVE	ORIFICE SIZE		LINER SIZE %	BODY ☐ Screwed ☐ Flanged		ANSI SERIES	MAX. WORKING PRESSURE
TYPE SERVICE	☐ Reducing ☐ Standby	☐ Back Pressure ☐ Monitor		Upstream:	Operating Pressure:		Downstream:

CONTROLLER

Manufacturer:	Model:	SPRING RANGE:	VARIABLE ORIFICE SETTING INLET: JACKET:

VALVE POSTIONER

Manufacturer:	Model:	Model: ☐ Direct ☐ Reverse

PILOT REGULATORS OR RELAYS

MANUFACTURER	TYPE	PRESS. UPSTREAM	PRESS. DOWNSTREAM

BY-PASS SIZE:	STATION VALVES CHECKED ☐ Yes ☐ No	MAX. INLET PRESS. EXPECTED AT THIS LOCATION:

VALVE SECURITY

Lock And Chain Required:	☐ YES	☐ NO
Lock And Chain In Place:	☐ YES	☐ NO

REMARKS

DISTRIBUTION:

____

____

____

____

Serviced By: ____________________

Witnessed By: ____________________

Supervisor: ____________________

TOC

Liquid Pipeline Relief Valve Capacity Review
Form #7.02C
Updated: Sept 2014

Line #:	Relief Valve Description	Flow Rate From Prover Report: BBLs/hour	Flow Capacity From Data Sheet: Gallons/minute	Conversion to BBL/Hr	Capacity Adequate? Yes/No If no, notice supervisor for relief valve replacement or pump down sizing	Additional Comments:
1	Hillcrest outlet shipping pump #1	47	68	97	Yes	
2	Hillcrest outlet shipping pump #2	47	68	97	Yes	
3	Hillcrest outlet shipping pump #3	47	68	97	Yes	
4	Rancho outlet shipping pump #1	39	68	97	Yes	
5	Rancho outlet shipping pump #2	39	68	97	Yes	

Date Review Completed: ______________

Name of Person Conducting the Review: ____________________________

Signature of Person Conducting the Review: ____________________________

TOC

PIPELINE QUALIFICATION RECORD
FOR HAZARDOUS LIQUID PIPELINES

OPERATING SYSTEM	

1. System Information	
a. Main Line System	
b. Segment	
c. AFE No.	
d. Date	
e. Drawing References	

2. Pipe Summary	
a. Size O.D. ( )	
b. Wall Thickness *(if unknown, see 195.106(c),(d))*	
c. Specification (API-5L, ASTM A53, etc.)	
d. Grade (B, X42, etc.)	
e. Pipe Class (SMLS, ERW, etc.)	
f. Length ( )	
g. DOT Class Location	
h. Maximum Operating Temperature (°)	
i. Pipe Manufacturer	
j. Year Manufactured	
k. Manufacturing Location	
l. Year Purchased	
m. Method of Transportation	

3. <u>Design Data</u>			
a. Yield Strength, “S” *(see 195.106(b))*			
b. Design Factor, “F” *(see 195.106(a))*			
c. Seam Joint Factor, “E” *(see 195.106(e))*			
d. ASME/ANSI Flange Rating (#)			

4. <u>Corrosion Data</u>			
a. Pipe Coated (Yes/No)			
b. Coating Material			
c. Method of Application			
d. Cathodic Protection (Yes/No) (If yes, date started)			
e. Type			
f. Corrosion Tests (1) Soil Resistivity (2) P/S Potential	Sta to Sta	Sta to Sta	Sta to Sta
g. Pipe Coated By			
h. Field Joint Coating			
i. Other CP Facilities			

5. <u>Construction Data</u>	
a. General	
(1) Contractor	
(2) Date Started	
(3) Date Completed	
(4) Depth of Cover ( )	

Construction Data (Continued)	
b. Welding Data	
(1) Company Inspector	
(2) Inspection Company	
(3) Type of Inspection	
c. Pressure Test Data	
(1) Tested By	
(2) Witnessed By	
(3) Type	
(4) Test Pressure ( )	
(5) Test Medium	
(6) Test Date	
(7) Test Duration (hr.)	
(8) Pressure Chart Make	
(9) Temperature Chart Make	
* (10) Accepted Test Pressure, "TP" ( )	

* Note: If there are significant elevation changes along the pipeline and a liquid is used as the test medium, the accepted test pressure will vary due to changes in hydrostatic head, and this variance must be taken into account when determining the MOP.

6. MOP Determination	
a. Pipe Design Pressure = (2St/D)xFxE *(see 195.106)*	
b. For converted pipe where one or more of the factors the equation from Item (a) above is unknown, Pipe Design Pressure is:	
(1) 80% of the first test pressure that produces yield (per N5.0 in appendix N of ASME B31.8), reduced by design factors of 195.106(a) and (e), or N/A	

MOP Determination (Continued)	
(2) If pipe is 12.75" (324 mm) O.D. or less, and is not tested to yield, Pipe Design Pressure = 200 PSIG (1379 kPa), or N/A *(See 195.406(a)(1))*	
c. Lowest Flange Pressure Rating	
d. Design pressure of any component, if less than flange pressure rating (PSIG), or N/A	
e. Maximum pressure substantiated by pipeline pressure test = 80% of test pressure *(see 195.406(a)(3))*	
f. If component not pressure tested with the rest of the pipeline, maximum pressure substantiated by component pressure test = 80% of factory test pressure or prototype test pressure, or N/A *(see 195.406(a)(4))*	
g. For pipelines under 195.302(b)(1) and (b)(2)(i) that have not been pressure tested per Item (e) above, 80% of the test pressure or highest operating pressure to which the pipeline was subjected for four (4) or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted, or N/A *(see 195.406(a)(5))*	
h. The maximum safe pressure as determined by the operator considering operating history, or N/A	
i. System Maximum Operating Pressure, “MOP” = Lowest of Items (a) through (h) above	
j. System Operating Pressure, "OP"	
k. MOP Certified By	
l. Date	

7. Miscellaneous Calculations	
a. Operating Pressure Hoop Stress (%S) = (OPxD/2t)x(100/S)	
b. Test Pressure Hoop Stress (%S) = (TPxD/2t)x(100/S)	
c. MOP Hoop Stress (%S) = (MOPxD/2t)x(100/S)	

DOT Pipeline MAOP / MOP Calculation

VENOCO, INC. REGULATED NATURAL GAS PIPELINES

Item No.	Pipeline Segment Name/ Line Number	California County	Location/ Destination/ Description	Onshore/ Offshore	Year Constructed	Commerce Type	Current Operating Status	Commodity Shipped	Gas Population-Class	Type	Yield Strength	thickness 192.109	Nominal Diameter	Outside Diameter	F 192.111 (Design Factor)	E 192.113 (joint Factor)	T 192.115 (Temp Factor)	192.105 (1)Design Pressure p-steel=(2*S*t/D)*F*E*T p-poly = (2*S/SDR-1)*0.32	HYDRO TEST PSI	(2) Hydro Test/1.5 192.619	ANSI Flange Rating (600-300-150)	(3) Max Pressure Flange Rating	PSV	192.619 MAOP (min 1, 2, 3)	Pressure for 20% of SMYS or 120 psi non-metallic	MAOP as % of SMYS	Total Length (ft)	Total Miles	Operating Pressure (psig)	Potential Impact radius	Predominate Coating Type	REPORTED PHMSA/DOT Mileage	Class 1 Mileage	Class 2 Mileage	Class 3 Mileage	Class 4 Mileage	Mileage within HCA	Mileage Installed 1950-1959	Mileage Installed 1960-1969	Mileage Installed 1970-1979	Mileage Installed 1980-1989	Mileage Installed 1990-1999	Mileage Installed 2000-2009	Mileage Installed 2010-2019	Mileage Cathodically Protected Bare	Mileage Cathodically Protected Coated	Mileage Cathodically Unprotected Bare	Mileage Cathodically Unprotected Coated
	Montalvo Sales Gas	Ventura	McGrath Lease #4 Pool Tank Setting to Tie-in to So Cal Gas S/O Olivas Park Dr	Onshore	1972	Intrastate	Active	Dry Gas	3	Transmission	24,000	0.375	5	5.563	0.6	1	1.000	1,941	500	333	600	1,480		333	647	10.3%	4,858	0.92	300	63	Somastic Coal Tar	0.92			0.92		0.92			0.92						0.92		
	Ellwood Sales Gas	Santa Barbara	Ellwood Onshore Facility to So Cal Gas Tie-in at west end of Holister Ave	Onshore	1966	Intrastate	Active	Dry Gas	3	Transmission	35,000	0.322	8	8.625	0.72	1	1.000	1,882	1,500	1,000	600	1,480		1,000	523	38.3%	10	0.00	950	275		0			0		0		0							0		
	Ellwood Sales Gas	Santa Barbara	Ellwood Onshore Facility to So Cal Gas Tie-in at west end of Holister Ave	Onshore	1966	Intrastate	Active	Dry Gas	3	Transmission	46,000	0.188	6	6.625	0.5	1	1.000	1,305	1,500	1,000	600	1,480		1,000	522	50.3%	3,480	0.66	950	131		0.17			0.17		0.17		0.17							0.17		
	Ellwood Sales Gas	Santa Barbara	Ellwood Onshore Facility to So Cal Gas Tie-in at west end of Holister Ave	Onshore	1995	Intrastate	Active	Dry Gas	3	Transmission	42,000	0.280	6	6.625	0.5	1	1.000	1,775	1,500	1,000	600	1,480		1,000	710	28.2%	2,400	0.45	950	131	X-tru-Coat	0.45			0.45		0.45					0.45				0.45		
	Ellwood Sales Gas	Santa Barbara	Ellwood Onshore Facility to So Cal Gas Tie-in at west end of Holister Ave	Onshore	1997	Intrastate	Active	Dry Gas	3	Transmission	35,000	0.280	6	6.625	0.5	1	1.000	1,479	1,500	1,000	600	1,480		1,000	592	33.8%	80	0.02	950	131	X-tru-Coat	0.02			0.02		0.02					0.02				0.02		
	Platform Grace Sales Gas M-1	N/A	Platform Grace on Federal Outer Continental Shelf to California State Waters Boundary	Offshore	1980	Interstate	Active	Dry Gas	1	Gathering	46,000	0.365	10	10.75	0.6	1	1.000	1,874	1,000	667	300	740		667	625	21.3%	62,300	11.80	150	178		11.8	11.8				11.8				11.8					11.8		
	Platform Grace Sales Gas M-1	Santa Barbara	California State Waters Boundary to Carpinteria Terminal	Offshore	1965	Interstate	Active	Dry Gas	1	Gathering	35,000	0.365	10	10.75	0.6	1	1.000	1,426	1,000	667	300	740		667	475	28.0%	19,010	3.60	150	178		3.6	3.6				3.6		3.6							3.6		
	Platform Holly Sour Gas	Santa Barbara	Platform Holly in California State Waters to Venoco Ellwood Onshore Facility	Offshore	1966	Intrastate	Active	Sour Gas	1	Gathering	35,000	0.280	6	6.625	0.6	1	1.000	1,775	982	655	600	1,480		650	592	22.0%	16,030	3.04	300	106		3.04	3.04				3.04									3.04		
	Platform Gail Sales Gas M-29	N/A	Platform Gail to Platform Grace on the Federal Outer Continental Shelf	Offshore	1988	N/A	Active	Dry Gas	1	Gathering	52,000	0.500	8	8.625	0.6	1	1.000	3,617		0	300	740		740	1,206	12.3%	33,200	6.29	150	150		6.29	6.29				6.29				6.29					6.29		

VENOCO, INC. REGULATED HAZARDOUS LIQUID PIPELINES

Item No.	Pipeline Segment Name/ Line Number	California County	Location/ Destination/ Description	Onshore/ Offshore	Year Constructed	Commerce Type	Current Operating Status	Commodity Shipped		Type	Yield Strength	thickness 195.106	Nominal Diameter	Outside Diameter	F 195.106 (Design Factor)	E 195.106 (joint Factor)		195.106 (1)Design Pressure P=(2*S*t/D)*F*E	HYDRO TEST PSI	(2) Hydro Test/1.25 195.304	ANSI Flange Rating (600-300-150)	(3) Max Pressure Flange Rating	PSV	192.619 MOP (min 1, 2, 3)	Pressure for 20% of SMYS	MOP as % of SMYS	length (ft)	Total Miles	Operational Pressure (psig)		Predominate Coating Type	REPORTED PHMSA/DOT Mileage					Mileage within HCA	Mileage Installed 1950-1959	Mileage Installed 1960-1969	Mileage Installed 1970-1979	Mileage Installed 1980-1989	Mileage Installed 1990-1999	Mileage Installed 2000-2009	Mileage Installed 2010-2019	Mileage Cathodically Protected Bare	Mileage Cathodically Protected Coated	Mileage Cathodically Unprotected Bare	Mileage Cathodically Unprotected Coated
	Beverly Hills Oil	Los Angeles	Beverly Hills Drill Site N/E corner Olympic Blvd & Heath Ave to Crimson Tie-in at W Pico Blvd, W/O Heath Ave	Onshore	1981	Intrastate	Active	Crude Oil		Trunk	46,000	0.25	6	6.625	0.72	1		2,500	915	732	300	712 130°F	612	690	694	19.9%	3,120	0.59	450		20 mils X-tru Coat	0.59					0.59				0.59					0.59		
	Beverly Hills Oil	Los Angeles	Beverly Hills Drill Site N/E corner Olympic Blvd & Heath Ave to Crimson Tie-in at W Pico Blvd, W/O Heath Ave	Onshore	1981	Intrastate	Active	Crude Oil		Trunk	46,000	0.237	4	4.5	0.72	1		3,489	915	732	300	712 130°F	612	690	969	14.2%	<10		450																			
	Beverly Hills Oil	Los Angeles	Beverly Hills Drill Site N/E corner Olympic Blvd & Heath Ave to Crimson Tie-in at W Pico Blvd, W/O Heath Ave	Onshore	1981	Intrastate	Active	Crude Oil		Trunk	35,000	0.281	6	6.625	0.72	1		2,138	915	732	300	712 130°F	612	690	594	23.2%	±100		450																			
	Carpinteria-Rincon	Santa Barbara / Ventura	Carpinteria Terminal to Rincon Station	Onshore	1980	Intrastate	Active	Crude Oil		Trunk	52,000	0.250	10	10.75	0.72	1		1,741		0	600	1,480		1,480	484	61.2%	31,680	6.00	300			6.00					6.00				6.00					6.00		
	Ventura Pipeline System Lateral M-144	Ventura	Front St. through Ventura Ave to Mohawk St Facility Tie-in at Ottowa St & Mohawk St	Onshore	1970	Intrastate	Active	Crude Oil		Trunk	42,000	0.250	12	12.75	0.72	1		1,186		0	300	720		720	329	43.7%	14,815	2.81	200		T-1 Wrap	2.81					2.81			2.81						2.81		
	Ventura Pipeline System M-143	Ventura	Rincon Station to Crimson Station Tie-in at Ventura Harbor	Onshore	1970	Intrastate	Active	Crude Oil		Trunk	52,000	0.312	22	22	0.72	1		1,062		0	150	275		275	295	18.6%	74,067	14.03	200		T-1 Wrap	14.03					14.03			14.03						14.03		
	Platform Holly Oil	Santa Barbara	Platform Holly in California State Waters to Venoco Ellwood Onshore Facility	Offshore	1966	Intrastate	Active	Oil Emulsion		Gathering	35,000	0.280	6	6.625	0.6	1		1,775	978	652	600	1,480		652	592	22.0%	16,030	3.04			Polyethylene 11 Xtru Coat	3.04					3.04		3.04							3.04		
	Platform Grace Oil M-2	N/A	Platform Grace on Federal Outer Continental Shelf to California State Waters Boundary	Offshore	1980	Interstate	Active	Crude Oil		Trunk	46,000	0.375	12	12.75	0.6	1		1,624	1,000	800	300	740		740	541	27.3%	62,810	11.90	280		1/2" Somastic and 1" Concrete	11.9					11.9				11.9					11.9		
	Platform Grace Oil M-2	Santa Barbara	California State Waters Boundary to Carpinteria Terminal	Offshore	1965	Interstate	Active	Crude Oil		Trunk	35,000	0.365	10	10.75	0.72	1		1,711	1,000	800	300	740		740	475	31.1%	19,380	3.67	200		3/4" Somastic	3.67					3.67		3.67							3.67		
	Ellwood Oil Transfer New Line 96	Santa Barbara	Ellwood Onshore Facility to Plains All American Tie-in w/o Las Flores Canyon	Onshore	2011	Intrastate	Active	Crude Oil		Trunk	52,000	0.28	6	6.625	0.72	1		3,165	2,160	1,728	600	1,440 130°F		1,440	879	32.8%	47,150	8.93	800		14 mil FBE	8.93					8.93							8.93		8.93		
	Platform Gail Oil M-28	N/A	Platform Gail to Platform Grace on the Federal Outer Continental Shelf	Offshore	1988	N/A	Active	Crude Oil		Trunk	52,000	0.500	8	8.625	0.6	1		3,617	1,670	1,336	600	1480		1,350	1,206	22.4%	33,400	6.33	1100			6.33					6.33				6.33					6.33		
	Platform Gail Oil M-30	N/A	Platform Gail to Platform Grace on the Federal Outer Continental Shelf	Offshore	1988	N/A	Active	Oil Emulsion		Trunk	52,000	0.500	8	8.625	0.6	1		3,617	1,690	1,352	600	1480		1,350	1,206	22.4%	33,100	6.27	150			6.27					6.27				6.27					6.27		
	State Lease 421-1 Oil	Santa Barbara	State Lease 421 to Venoco Ellwood Onshore Facility	Onshore	1966	Intrastate	Out-of-Service	N/A		N/A			6	6.623	0.72	1		0		0				0	0	#DIV/0!	1,950	0.37																				
	Ellwood Terminal Loading	Santa Barbara	Venoco Ellwood Terminal to Sea Floor (California State Waters)	Offshore	1967	Intrastate	Out-of-Service	N/A		N/A			12	12.75	0.72	1		0		0				0	0	#DIV/0!	775	0.15																				
	Ellwood Terminal Loading	Santa Barbara	Venoco Ellwood Terminal to Sea Floor (California State Waters)	Offshore	1967	Intrastate	Out-of-Service	N/A		N/A	35,000	0.344	10	10.75	0.72	1		1,613		0				0	448	0.0%	2,825	0.54			.060" X-Tru-Coat Plastic																	
	Ellwood Terminal Loading	Santa Barbara	Venoco Ellwood Terminal to Sea Floor (California State Waters)	Offshore	1993	Intrastate	Out-of-Service	N/A		N/A			8	8.625	0.72	1		0		0				0	0	#DIV/0!	240	0.05																				
	Ellwood Oil Transfer Old Line 96	Santa Barbara	Ellwood Onshore Facility valve #1291 to Ellwood Marine Terminal	Onshore	1982	Intrastate	Out-of-Service	N/A		N/A	42,000	0.250	10	10.75	0.72	1		1,407		0				0	391	0.0%		0.00																				
	Ventura Pipeline System Lateral M-144	Ventura	Mohawk St Facility to Willet Lease Tank Farm	Onshore	1970	Intrastate	Out-of-Service	N/A		N/A	42,000	0.219	8	8.625	0.72	1		1,536		0				0	427	0.0%	1,687	0.32	150																			

Conversion of Service (step by step)
O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
1.	Conduct historical records study by reviewing design, construction, operation, and maintenance history of the pipeline. Use form #12.02A and form #12.02B (pipeline fact sheet template) or equivalent to document this review. Target Date for Completion:				
2.	Make determination if sufficient historical records are not available, and then appropriate tests must be conducted to determine if the pipeline is safe to operate. (Select all that apply) ○ Corrosion surveys including one or more of the processes used in the integrity management program: ○ External Corrosion Direct Assessment (ECDA) evaluations. These normally include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM) ○ In line inspection (ILI) tools ○ Guided wave ○ Ultrasonic inspections for corrosion and wall thickness determinations ○ Positive material identification inspection				

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
	using portable XRF analyzers ○ Acoustic emissions inspection ○ Tensile tests ○ Internals inspections in accordance with O&M procedure #6.02 ○ Radiographic inspections Target Date for Completion:				
3.	Review tests results from item selected in step #2. Document review and any new action items. Target Date for Completion:				

Conversion of Service (step by step)
O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
4.	Visually inspect the pipeline right-of-way, all aboveground segments, and appropriate underground segments of the pipeline for physical defects or other conditions which could impair the strength or tightness of the line. Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites: ○ Corrosion surveys ○ Segments with coating damage or deterioration due to soil stresses and/or internal or external temperature extremes ○ Pipeline component locations ○ Locations subject to mechanical damage ○ Foreign pipeline crossings ○ Locations subject to damage due to chemicals such as acid ○ Population density Document inspection and any new action items. Target Date for Completion:				

Conversion of Service (step by step)
O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
5.	Correct any defects or conditions discovered during reviews and/or inspections prior to line commissioning. Document all remedial action and any new action items. This includes but is not limited to; coating damage, pipeline repairs of internal/external corrosion, etc. Target Date for Completion:				
6.	Determine new MOP for the line in accordance with 192.619 and Procedure 8.01. Document new MOP and any new action items Target Date for Completion:				

Conversion of Service (step by step)
O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
7.	Conduct a pressure test the line to substantiate the new line MOP in accordance with 192 subpart J and procedure #15.01. Schedule CSFM certified pressure testing company to conduct pressure test. See attached list of CSFM certified pressure testing companies obtained from CSFM website. Make repairs discovered during the hydro test using O&M procedure #9.01. Document pressure test and any new action items. Target Date for Completion:				
8.	Conduct high consequence area (HCA) survey in accordance with 192.5 and compare the proposed MOP and operating stress levels with those allowed for the location class. Replace pipe and/or facilities to make sure the operating stress levels is commensurate the location class. Target Date for Completion:				

Conversion of Service (step by step)

O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
9.	Within one year of the date that the converted line is placed in gas service, provide cathodic protection as required by 192.455. Document design and installation of CP system and any new action items. Target Date for Completion:				
10.	Include the pipeline in the next PHMSA annual report. Target Date for Completion:				
11.	If the converted pipeline is transmission, submit to the National Pipeline Mapping System (NPMS). Target Date for Completion:				
12	Develop pipeline specific O&M (PSOM) for this new pipeline. Document PSOM date and any new action items. Target Date for Completion:				

Conversion of Service (step by step)
O&M Procedure Form 12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:

Compliance Mgr Signature and Date: ______________________ ________
Signature Date

Operations Mgr Signature and Date: ______________________ ________
Signature Date

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FACILITY ABANDONMENT RECORD

FORM 13.01A

COMPANY:	DISTRICT / LOCATION:	DATE: MO-DAY-YR
SYSTEM:		
DESCRIPTION OF FACILITY:		
TYPE OF SERVICE:	☐ Natural Gas	☐ Liquid
LOCATION:		
CITY:	COUNTY:	STATE:
SECTION:	TOWNSHIP:	RANGE:
DATE PLACED IN SERVICE:	DATE ABANDONED:	
Type of Abandonment	☐ In Place	☐ Removed
If abandoned in place, describe final position of ownership.		
Purged with:		
Filled with:		
Describe procedure used to insure that no volatile flammable hydrocarbons remained in the facilities:		
PREPARED BY:		LOCATION MANAGER APPROVAL:

Distribution:

Signatures:

Completed By: ______________________

Supervisor: ______________________

____

____

____

____

Monthly Firefighting Equipment Inspection
O&M Form 14.05A

Reference: 49 CFR 195.430, OSHA 29 CFR 1910.157(e)(2), NFPA 10

Date Revised: Sept 2014

Pipeline System: ❑

Frequency: Monthly visual inspections [OSHA 29 CFR 1910.157(e)(2) and NFPA 10]

Action: Perform monthly visual inspection and use form #14.05A or equivalent. Verify that all firefighting equipment is: [OSHA 29 CFR 1910.157 and NFPA 10]

☐ sat	☐ unsat	❑ In proper operating condition at all times
☐ sat	☐ unsat	❑ Plainly marked as firefighting equipment
☐ sat	☐ unsat	❑ Located so that it is easily accessible during a fire
☐ sat	☐ unsat	❑ Any factor affecting safety & operation
☐ sat	☐ unsat	

Comments: Any condition found during monthly visual inspection listed above shall be remedied as soon as is practicable. Make comments on all unsat conditions above.

Signature & Date:

____
Work Completed By (signature)

____
Date

____
Reviewed By (signature)

____
Date

CALIFORNIA STATE FIRE MARSHAL

PIPELINE SAFETY DIVISION

HYDROSTATIC TEST RESULTS

PIPELINE DATA-Form 15.01

Test Date	CSFM Test ID #
Pipeline Operator	Independent Testing Firm

Kind of Test [ ] Annual [ ] 2 Year [ ] 3 Year [ ] 5 Year [ ] 10 Year

Pipeline Identification (description, line number, name, pre-tested pipe, etc.)

[ ] Pre-tested pipe [ ] New [ ] Replacement or relocation [ ] Station piping

Pipeline Location (mile post, street, station, GPS points, etc.)

CSFM #: 00000-0000	From: To:

Normal Product Transported

Test Medium [ ] Water [ ] Diesel [ ] Fuel Oil [ ] JP-5 [ ] Other

Location of Deadweight Tester	Elevation

Elevation of Pipeline – High Point Low Point

Maximum Operating pressure (Based on 80% of Minimum Test Pressure)

PIPE DATA

Pipe O.D.	Wall Thickness	Specification & Grade (SYMS)	Length of Pipe Being Tested (ft.)	Volume (Barrels)

TEST EQUIPMENT

Make of Deadweight Tester	Serial #	Date Last Calibrated
Make of Pressure Chart Recorder	Serial #	Date Last Calibrated
Make of Temperature Recorder	Serial #	Date Last Calibrated

COMMENTS (additional information)

GPS LOCATIONS:

Beginning Location:	**Ending Location:**
Latitude:	Latitude:
Longitude:	Longitude:

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TEST DATA					CSFM TEST ID #			
Date	Time	Deadweight Pressure (psig)	Chart Pressure (psig)	Pipe Wall Temp	Ambient Temp	Medium Temp	Test Medium Change (+)Added (-) Drained	Comments
Net Change								

LIST ALL LEAKS ON LINE PIPE RESULTING FROM UNSUCCESSFUL TEST ATTEMPTS	
LOCATION	CAUSE

CERTIFICATION	
Name of Company Conducting Test	
Name of Independent Testing Firm Witnessing Test	
Name of Certified Independent Witness on Site	Date
Pipeline Operator’s Representative on Site	Date
Name of Person Certifying Test Data for Witnessing Firm	Date

California State Fire Marshal							
Hydrostatic Test Calculation Worksheet						**Form 15.01B**	
Test Medium: Water							
CSFM Test ID#		03-005		Test date:		01/09/02	
Enter initial temperature:		40.0		Enter initial pressure:		2.0	PSIG
Enter final temperature:		145.0		Enter final pressure:		7900.0	PSIG
Water added (Subtracted):		0.0	Gallons				
Test Duration		4.0	Hours				

Stationing:	Pipe O.D. (in)	Wall Thickness (in)	Length (ft)	Line Fill (gals)		Kp Calculation initial	CPSA Loss
	1.050	0.500	0.0	0.00		0	0.00
	3.500	0.500	0.0	0.00		0	0.00
	4.500	0.500	0.0	0.00		0	0.00
	6.625	0.375	0.0	0.00		0	0.00
	6.625	0.365	0.0	0.00		0	0.00
	8.625	0.322	0.0	0.00		0	0.00
	8.625	0.188	0.0	0.00		0	0.00
	10.750	0.188	0.0	0.00		0	0.00
	12.750	0.375	160.5	942.97		1907	0.04
	12.750	1.000	0.0	0.00		0	0.00
	26.000	0.188	0.0	0.00		0	0.00
	36.000	0.154	0.0	0.00		0	0.00
TOTALS			160.5	943		11.88	-1.04
CPSA Allowable Hourly Loss	-1.036	gals					

Press Change	dP =	7898.00	psi
Temp Change	dT =	105.00	deg. F
Add/Sub Gals.		0.00	gals
Calculated average for use in table:		92.50	deg. F
Bulk Modulus (From table)		92	psix10^3
Liquid Volumetric Expansion Coefficient (Table)		92.00	x10^-5
	Kt =	-90.05	x10^-5
	Kp =	11.88	x10^-6

dV/V =KpdP + KtdT

Net Vol Change (dV):	-0.661	gals
Net Vol Change (gph):	**-0.165**	gals/hr
CPSA Allowable Loss:	-1.036	gals/hr
	Pass	

Company Name:

Segment Under Test

Stationing and GPS points

FN: Form #16.01A Pipeline Training Plan Template, v2013-1
Date Revised: August 1, 2013
Printing Note: Use 11" x 17" landscape format

Line #:	Description of Pipeline Training	Regulation:	Training Category	Training Frequency	Method for Compliance		Pipeline Advisor:	Pipeline Engineer:	Pipeline Supervisor:	Pipeline Operator Control Room:	Pipeline Operator Field O&M:	Pipeline Contractor:
1	General O&M Requirements	195.402(a)	O&M	AR	Online O&M at www.compliancerivesinc.net		Yes	Yes	Yes	Yes	Yes	NA
2	Corrosion Control: Verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under § 195.402(c)(3) for which they are responsible for insuring compliance	195.555	Corrosion	1x/3yr	Online OQ at www.compliancerivesinc.net		Yes	NA	NA	NA	NA	NA
3	Continuing Pipeline Emergency Response Trng (including verification of supervisor knowledge) including the <u>following minimum topics</u>: (1) Carry out the emergency procedures established under 195.402 that relate to their assignments; (2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions; (3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action; (4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and (5) Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.	195.403	ERP	Initial & 1x/yr, not to exceed 15 months	Classroom training, or emergency dril, or emergency drill with agencies.		Yes	Yes	Yes	Yes	Yes	NA
4a	Response Plans for Onshore Oil Pipelines: (a) Each operator shall conduct training to ensure that: (1) All personnel know— (i) Their responsibilities under the response plan, (ii) The name and address of, and the procedure for contacting, the operator on a 24-hour basis, and (iii) The name of, and procedures for contacting, the qualified individual on a 24-hour basis;	194.117(a)(1)	ERP	Initial & 1x/yr	Classroom training, or emergency dril, or emergency drill with agencies.		Yes	Yes	Yes	Yes	Yes	Yes

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4b	Response Plans for Onshore Oil Pipelines: (a) Each operator shall conduct training to ensure that: (2) Reporting personnel know— (i) The content of the information summary of the response plan, (ii) The toll-free telephone number of the National Response Center, and (iii) The notification process;	194.117(a)(2)	ERP	Initial & 1x/yr	Classroom training, or emergency dril, or emergency drill with agencies.		Yes	Yes	Yes	Yes	Yes	Yes
4c	Response Plans for Onshore Oil Pipelines: (a) Each operator shall conduct training to ensure that: Personnel engaged in response activities know— (i) The characteristics and hazards of the oil discharged, (ii) The conditions that are likely to worsen emergencies, including the consequences of facility malfunctions or failures, and the appropriate corrective actions, (iii) The steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity, or environmental damage, and (iv) The proper firefighting procedures and use of equipment, fire suits, and breathing apparatus.	194.117(a)(3)	ERP	Initial & 1x/yr	Classroom training, or emergency dril, or emergency drill with agencies.		Yes	Yes	Yes	Yes	Yes	Yes
5	Hazwoper and Hazwoper Refresher	OSHA 29 CFR 1910.120, & 194.117(c)	ERP	Initial & 1x/yr	Online O&M at www.complianceserivesinc.net		Yes	Yes	Yes	Yes	Yes	Yes
6	Operator Qualification (see OQ plan)	195.501	OQ	Initial & 1x/3yrs	Online OQ at www.complianceserivesinc.net		Yes	Yes	Yes	Yes	Yes	Yes

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7	Construction Inpector Training	195.204	Construction Inspetor	Initially and 1x/3yr for critical skills			NA	NA	NA	NA	NA	Yes
8	NDT Training and Qualificaton under ASNT Recommended Practice SNT-TC-1A. When operator inspects welds using NDT, interpretation personnel are Level II or Level III	195.234(b)	NDT	AR and 1x/3yrs			NA	NA	NA	NA	NA	Yes
9	Computational Pipeline Monitoring (CPM) dispatcher training of the system	195.444	CPM	Initial & 1x/3yrs			NA	NA	NA	Yes	NA	NA
10	Control Room Management (CRM)	195.446	CRM	Initial & 1x/3yrs			NA	NA	NA	Yes	NA	NA

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Annual Review for Meeting Objectives of Pipeline Emergency Training
O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
1.	Conduct historical records study by reviewing design, construction, operation, and maintenance history of the pipeline. Use form #12.02A and form #12.02B (pipeline fact sheet template) or equivalent to document this review. Target Date for Completion:				
2.	Make determination if sufficient historical records are not available, and then appropriate tests must be conducted to determine if the pipeline is safe to operate. (Select all that apply) ○ Corrosion surveys including one or more of the processes used in the integrity management program: ○ External Corrosion Direct Assessment (ECDA) evaluations. These normally include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM) ○ In line inspection (ILI) tools ○ Guided wave ○ Ultrasonic inspections for corrosion and wall thickness determinations ○ Positive material identification inspection				

Annual Review for Meeting Objectives of Pipeline Emergency Training
O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
	using portable XRF analyzers ○ Acoustic emissions inspection ○ Tensile tests ○ Internals inspections in accordance with O&M procedure #6.02 ○ Radiographic inspections Target Date for Completion:				
3.	<u>Review tests results</u> from item selected in step #2. Document review and any new action items. Target Date for Completion:				

Annual Review for Meeting Objectives of Pipeline Emergency Training

O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
4.	<u>Visually inspect</u> the pipeline right-of-way, all aboveground segments, and appropriate underground segments of the pipeline for physical defects or other conditions which could impair the strength or tightness of the line. Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following <u>criteria should be used for the selection of inspection sites</u>: ○ Corrosion surveys ○ Segments with coating damage or deterioration due to soil stresses and/or internal or external temperature extremes ○ Pipeline component locations ○ Locations subject to mechanical damage ○ Foreign pipeline crossings ○ Locations subject to damage due to chemicals such as acid ○ Population density Document inspection and any new action items. Target Date for Completion:				

Annual Review for Meeting Objectives of Pipeline Emergency Training
O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
5.	Correct any defects or conditions discovered during reviews and/or inspections prior to line commissioning. Document all remedial action and any new action items. This includes but is not limited to; coating damage, pipeline repairs of internal/external corrosion, etc. Target Date for Completion:				
6.	Determine new MOP for the line in accordance with 192.619 and Procedure 8.01. Document new MOP and any new action items Target Date for Completion:				

Annual Review for Meeting Objectives of Pipeline Emergency Training
O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
7.	Conduct a pressure test the line to substantiate the new line MOP in accordance with 192 subpart J and procedure #15.01. Schedule CSFM certified pressure testing company to conduct pressure test. See attached list of CSFM certified pressure testing companies obtained from CSFM website. Make repairs discovered during the hydro test using O&M procedure #9.01. Document pressure test and any new action items. Target Date for Completion:				
8.	Conduct high consequence area (HCA) survey in accordance with 192.5 and compare the proposed MOP and operating stress levels with those allowed for the location class. Replace pipe and/or facilities to make sure the operating stress levels is commensurate the location class. Target Date for Completion:				

Annual Review for Meeting Objectives of Pipeline Emergency Training

O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
9.	Within one year of the date that the converted line is placed in gas service, provide cathodic protection as required by 192.455. Document design and installation of CP system and any new action items. Target Date for Completion:				
10.	Include the pipeline in the next PHMSA annual report. Target Date for Completion:				
11.	If the converted pipeline is transmission, submit to the National Pipeline Mapping System (NPMS). Target Date for Completion:				
12	Develop pipeline specific O&M (PSOM) for this new pipeline. Document PSOM date and any new action items. Target Date for Completion:				

Annual Review for Meeting Objectives of Pipeline Emergency Training

O&M Form #16.01-B

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:

Compliance Mgr Signature and Date: ______________________________ ____________

Signature Date

Operations Mgr Signature and Date: ______________________________ ____________

Signature Date

REPORTING AND CONTROL OF INCIDENTS
Hazardous Liquid Pipeline O&M Procedure #1.01

Primary Ref: 49 CFR 195.50 - 195.62	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.50, 195.52, 195.54, 195.58, 195.60, 195.62, CSPA 51018, 195.402(c)(2), and PHMSA Advisory ADB 10-04, April 29, 2010, and PHMSA accident report form #7000-1.

2. PURPOSE

The purpose of this procedure is to establish responsibilities for activities associated with regulated pipeline facility accidents (refer to Procedure 1.04 for the definitions of regulated lines). These activities include, but are not limited to, accident control, repair, reporting, investigation and documentation.

3. RESPONSIBILITY FOR IMPLEMENTATION - ALL PROCEDURES

The (1) ______________ is responsible for the documentation and reporting of pipeline facility accidents.

4. PHMSA ACCIDENT REPORT CRITERIA [195.50]

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator.

(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

(1) Not otherwise reportable under this section;

(2) Not one described in §195.52(a)(4);

(3) Confined to company property or pipeline right-of-way; and

(4) Cleaned up promptly;

(c) Death of any person;

(d) Personal injury necessitating hospitalization;

(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

Use PHMSA Form 7000-1-1 for submitting the report.

5. PHMSA IMMEDIATE NOTICE OF CERTAIN ACCIDENTS [195.52]

At the earliest practicable moment (within one to two hours) following the discovery of a hazardous liquid release meeting at least one of the criteria below, the DOT must be contacted by telephone at (800) 424-8802 (National Response Center – NRC) and notified of any release resulting in any of the following:

(1) Caused a death or a personal injury requiring hospitalization;

(2) Resulted in either a fire or explosion not intentionally set by the operator;

(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

Information required. Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202–267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Name, address and identification number of the operator.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) Initial estimate of amount of product released in accordance with paragraph (c) of this section.

(7) All other significant facts known by the operator that is relevant to the cause of the failure or extent of the damages.

Calculation. The company must have a written procedure to calculate and provide a reasonable initial estimate of the amount of released product. See section #8.7 below for release calculation.

New information. The company must provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response phase of a reported event at the earliest practicable moment after such additional information becomes known.

6. REPORT SUBMISSION REQUIREMENTS [195.58]

6.1 Except safety-related condition report (§191.25) or an offshore pipeline condition report, the company must submit each report required by this procedure electronically to the Pipeline and Hazardous Materials Safety Administration. Use the following web site unless an alternative reporting method is authorized in accordance with requirements below.

PHMSA accident reporting website:

Please use the PHMSA portal to submit reports for 2010 and later. http://portal.phmsa.dot.gov/pipeline

6.2 ***Exceptions****.* The company is not required to submit a safety-related condition report (§191.25) or an offshore pipeline condition report (§191.27) electronically.

6.3 ***Alternative Reporting Method****.* If electronic reporting imposes an undue burden and hardship, the company shall submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA shall review the request and may authorize, in writing, an alternative reporting method. An authorization shall state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

7. WRITTEN REPORT SUBMISSION DEADLINE [195.54]

When the company experiences an accident that is required to be reported under §195.50 must, as soon as practicable, but not later than 30 days after discovery of the accident, file an accident report on DOT Form 7000–1.

Whenever the company receives any changes in the information reported or additions to the original report on DOT Form 7000–1, it shall file a supplemental report within 30 days. Note, this report may be submitted electronically (see section #6 of this procedure).

8. CALIFORNIA STAT*E* OFFICE OF EMERGENCY SERVICES AND LOCAL AGENCY ACCIDENT REPORT CRITERIA

Every rupture, explosion, or fire involving a hazardous liquid pipeline must be immediately reported to the local fire department or other agency having jurisdiction.

A "rupture" includes every unintentional hazardous liquid leak, including any leak that occurs during hydrostatic testing, with the exceptions of:

- A crude oil leak of less than 5 barrels from a pipeline or flow line in a rural area.
- A crude oil or petroleum product leak in any in-plant piping system of less than 5 barrels, when no fire, explosion, or bodily injury results, or no waterway is contaminated.

9. GENERAL

The Incident and Service Interruption Report form (Form 1.01B) is a checklist intended to assure accurate conveying and recording of information transmitted by telephone. This form or an equivalent may be used to facilitate this information.

For all incidents where liability is in question, the (3) _______________ shall:

- Review planned responses to outside parties, such as government agencies, outside investigators, and attorneys for information.

- Provide advice regarding press releases.
- Review all reports and the final report to management.

Chart 1.01A (California state notification) and 1.01B (federal notification) should be used to assist in the sequence of incident and notification process.

10. FIRST RESPONDER RESPONSIBILITIES

8.1 Company First Responder responsibilities include the following:

8.1.1 Establish control of each accident.

8.1.2 Immediately after initial control is established and a preliminary assessment of conditions can be made, call the (4) ______________, if not present at the location, and report those incidents meeting one of the Reporting Criteria listed above in Sections 4 and 5 of this procedure.

8.2 The responsibilities of the (5) ______________ include the following:

8.2.1 Receive telephone reports of those incidents meeting one of the above-listed accident Reporting Criteria. Communicate the situation to designated people within the District Office.

8.3 The responsibilities of the (6) ______________ include the following:

8.3.1 Coordinate all on-site activities including such things as repair, responding to reporters, preservation of evidence and materials, internal reporting and documentation of events and actions.

8.3.2 Secure the site and maintain it undisturbed if possible, until the appropriate Company representative is on site. If the site cannot be left undisturbed, document the site and incident details and preserve the site and details as indicated in the appropriate emergency plan or in Investigation of Failures and Accidents (Procedure 1.03).

8.4 The responsibilities of the (7) ______________ include the following:

8.4.1 Documentation and/or investigation of incidents as necessary to meet operational requirements. Use the Incident and Service Interruption Report form or equivalent as a reference for the information to be reported (Form 1.01B) and submit it to the (8) ______________ as soon as possible (see 8.7.6).

8.4.2 Arrange for interviews of employees as required.

8.5 The responsibilities of the (9) ______________ may include the following:

8.5.1 The (10) ______________ shall arrange for the shipment of materials or evidence to specified locations.

8.5.2 Arrange for outside professional services to assist in an investigation (e.g., corrosion specialist, land surveyor, metallurgist, or welding engineer) if deemed necessary.

8.5.3 Analyze field data collected, operating history of facility and results of lab testing to establish cause of failure or condition and write reports as necessary.

8.5.4 Provide recommendations for operational changes or facility modifications as appropriate.

8.6 The Company Legal Department shall review written recommendations for operational procedure changes prior to issuing field use.

8.7 The responsibilities of the (11) __________________ may include the following:

8.7.1 Evaluate if reportable in conjunction with legal staff, if appropriate.

Use the following formula to determine the volume of the release, if any.

Thickness (feet) x length (feet) x width (feet) = Total volume in cubic feet.
To convert to gallons: total cubic feet x 7.48 = total gallons

The person responsible for making the report to PHMSA under this section #8.7 (#11 in the assignment table) of this procedure shall visit the release area to make the estimate of the released volume, or get input from field personnel to make this estimate of release volume.

8.7.2 Report accidents/incidents meeting the PHMSA TELEPHONE REPORT CRITERIA, see section 5 of this procedure, by telephone to (800) 424-8802 (National Response Center – NRC). Use Form 1.01B to convey the required information. Telephonic notice must occur within one to two hours. Report shall include the following information:

<u>CAUTION:</u> Anything that is said or written to the NRC becomes evidence in an "incident".

8.7.2.1 Name(s) of person(s) making report and their telephone numbers.

8.7.2.2 The location of accident.

8.7.2.3 The time of the accident.

8.7.2.4 The number of fatalities and personal injuries, if any.

8.7.2.5 All other significant facts that are known to be relevant to the cause of the incident or extent of the damages.

8.7.3 Obtain an incident identification number from the NRC, and complete all required forms.

8.7.4 Receive requests for data, information or on-site investigation and respond to those requests after collaboration with other persons (Operations, Safety, Security, and Legal staff) as determined necessary or appropriate.

8.7.5 Provide on-site investigation of incidents meeting one of the Reporting Criteria, on a case by case basis.

8.7.6 Report incidents meeting one of the California State Office of Emergency Services and Local Agency Report Criteria by phone immediately to the Office of Emergency Services (OES) at 800-852-7550.

8.7.7 Where additional related information is obtained after a report is submitted, the (15) ______________ shall make a supplemental report as soon as practical, but no later than 30 days after acquiring the additional information, with a clear reference by date and subject to the original report. Write "Supplemental Report" at top of Form 7000-1 report. Also phone the Office of Emergency Services to advise them of the changed situation. Supplemental reports shall be submitted a minimum of once every six (6) months until the investigation is complete.

8.7.8 Each report submitted shall indicate whether it is the initial report, supplemental report, or final report.

8.7.9 Submit copies of all accident reports to other agencies, if applicable, and to the District Office.

9. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
1.03 Investigation of Failures and Accidents
3.04 Preparation of a System Specific Emergency Plan

10. RECORDS

10.1 The (16) ______________ shall maintain the official files on incidents meeting one of the Reporting Criteria that are reported to outside agencies. Keep a copy of PHMSA form # 7000-1 to document the accident report.

10.2 Each file shall be kept for the life of the pipeline. Legal Department shall be contacted prior to destroying a file.

REPORTING OF SAFETY RELATED CONDITIONS
Hazardous Liquid Pipeline O&M Procedure #1.02

Primary Ref: 49 CFR 195.55 - 195.402	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.55, 195.56, 195.58, 195.402(f), and Ca. Gov. Code 51010.

2. PURPOSE

The purpose of this procedure is to define safety-related conditions and establish responsibilities for reporting safety related conditions on Company pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (22) _______________ is responsible for the determination, evaluation, and correction of safety related conditions and reporting of these items to the governing agencies. The (23) _______________ is responsible to train operating personnel to insure that they are capable of properly identifying and interpreting safety related conditions.

4. GENERAL

4.1 Designated operating personnel shall look for possible safety related conditions while conducting routine operating functions and when following applicable procedures for inspections and surveillance.

4.2 The (24) _______________ or designated operating personnel shall complete the Safety Related Conditions Report (Form 1.02B). If completed by operating personnel, Form 1.02B must be provided to the (25) _______________ as soon as possible, but not more than five (5) working days after discovery.

4.3 The (26) _______________ is responsible for evaluating safety related conditions and reporting to governing agencies. Reports must be received by the governing agencies no later than five (5) working days after the day of determination or ten (10) working days after the day of discovery.

4.4 If a possible safety related condition is discovered which results in taking the facility out of service due to an incident before determination, and not more than five (5) working days from discovery, the reporting requirements of this procedure are eliminated.

4.5 "Safety Related Condition," as defined in Item 5.1 below, is a condition which lies within 220 yards (200 meters) of any building intended for human occupancy or outdoor place of assembly, within the right-of-way of an active railroad, asphalt or concrete paved road, street or highway, and offshore locations or onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, or other body of water.

4.6 "Discovery Date" is the date that a condition is identified that may be classified as a safety related condition under this procedure, but requires additional evaluation or analysis.

4.7 "Determination Date" is the date when a condition evaluation results in the conclusion that it is a safety related condition.

4.8 "Working Days" are Monday through Friday, except Federal holidays. (See List of Federal Holidays at the end of this procedure.)

4.9 The company shall provide instruction and/or training to pipeline supervisors and pipeline operators who perform operation and maintenance activities to enable them to recognize conditions that potentially may be safety related conditions that are subject to the reporting requirements of 195.55.

5. <u>PROCEDURE</u>

5.1 Safety Related Conditions

The following conditions are defined as safety related conditions and must be reported per 5.2 below:

5.1.1 General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure (MOP), and localized corrosion pitting to a degree where leakage might result.

5.1.2 Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, that impairs its serviceability.

5.1.3 Any material defect or physical damage that impairs the serviceability of the pipeline.

5.1.4 Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure (MOP).

5.1.5 A leak in a pipeline that constitutes an emergency.

5.1.6 Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for

purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

5.1.7 Pipeline shutdowns caused by non-pipeline-related facilities are <u>not reportable</u>.

5.1.8 Reduction in pressure as a precaution to avoid an unsafe condition for the following activities is <u>not reportable</u>.

5.1.8.1 Abandonment of pipeline facilities.

5.1.8.2 Routine maintenance or construction.

5.1.8.3 Facilitate inspection for potential problems.

5.1.8.4 Avoid problems related to external loading from blasting or subsidence.

5.1.8.5 Provide for safe line movement.

5.2 Reporting Safety Related Conditions

5.2.1 <u>Report</u> safety related conditions to regulatory agencies for:

5.2.1.1 All safety related conditions resulting from defects outlined in 5.1.1, regardless of when the condition is repaired.

5.2.1.2 All safety related conditions resulting from defects outlined in 5.1.2 through 5.1.6, that are not corrected or repaired within five (5) working days after determination that a condition exists, but not later than ten (10) working days after discovery of the condition.

5.2.2. A <u>report is not required</u> for any safety-related condition that-

5.2.2.1. Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water.

5.2.2.2. Is an accident that is required to be reported under Procedure 1.01 (195.50) or results in such an accident before the deadline for filing the safety-related condition report, or

5.2.2.3. Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for all conditions under 5.1.1 of this Procedure other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

5.2.3 Operating personnel shall contact the District Engineer promptly if a possible safety related condition is discovered.

5.2.4 Operating personnel shall provide relevant information on an expedited schedule to support the timely submission of reports to DOT. The Safety Related Condition Report (Form 1.02B) form is to be used as a communication tool by operating personnel to provide proper information to the (27) ______________. If the (28) ______________ determines that a reportable safety related condition exists, then the (29) ______________ shall complete Form 1.02B. In either case, the form must be completed and a report submitted by the (30) ______________ within one (1) working day after the determination, but not later than five (5) working days after discovery of the condition.

5.2.5 Use Chart 1.02A, as a guide for determination of safety related conditions.

5.2.6 The (31) _______________ shall evaluate and confirm the reportability of a condition. If a condition is determined to be reportable, the (32) _______________ shall submit the necessary written report to the appropriate agencies.

The (33) _______________ shall prepare a written report on reportable safety related conditions and send it to the (34) _______________ for review. The report must be forwarded to the (35) _______________ to allow ample time for review prior to the DOT deadline. The (36) _______________ must submit a final report that shall be received by the DOT within five (5) working days (not including Saturdays, Sundays, or Federal holidays) of determination, but not later than ten (10) working days after discovery of the condition, at the following address:

Information Resources Manager
Office of Pipeline Safety
Pipeline and Hazardous Material Safety Administration (PHMSA)
PHP-20
1200 New Jersey Ave, SE
Washington, DC 20590

5.2.7 Form 1.02B may be used to report a safety related condition to DOT and must contain the following information. To file a report by facsimile (fax), dial (202) 366–7128.

The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow up or future corrective action, including the anticipated schedule for starting and concluding such action.

5.3 For regulated pipelines in California, a report is also required to the CSFM. [Ca. Gov. Code 51010]

6. RELATED PROCEDURES

1.01 Reporting of Control of Accidents
1.03 Investigation of Failures and Accidents
5.01 Continuing Surveillance
9.01 Repair Procedures

7. RECORDS

7.1 For intrastate pipelines, and in states where the state is an Agent for DOT, a report copy shall be sent concurrently to the applicable state agency.

7.2 Copies of Form 1.02B and reports to DOT or other agencies shall be sent to the applicable company offices.

7.3 A copy of all correspondence related to reported conditions shall be kept by the District Office for five (5) years.

7.4 Reports on all corrective actions taken shall be kept by the District Office for the life of the system.

LIST OF FEDERAL HOLIDAYS

New Years Day	January 1
Martin Luther King Day	Third Monday in January
Washington's Birthday	February 22
Memorial Day	Last Monday in May
Independence Day	July 4
Labor Day	First Monday in September
Columbus Day	Second Monday in October
Veterans Day	November 11
Thanksgiving	Fourth Thursday in November
Christmas	December 25

INVESTIGATION OF FAILURES AND ACCIDENTS
Hazardous Liquid Pipeline O&M Procedure #1.03

Primary Ref: 49 CFR 195.60, 195.402, 195.402, 199.11	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.60, 195.402(c)(5), 195.402(c)(6), 199.11(b) and company Root Cause Analysis procedures.

2. PURPOSE

The purpose of this procedure is to establish responsibilities for activities associated with investigation, analysis, and documentation of pipeline facility failures and incidents.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (42) ______________ is responsible for investigation, analysis, and documentation of pipeline facility failures and incidents.

4. GENERAL

4.1 The (43) ______________ is responsible for investigating the cause of incidents reported to State and Federal Agencies.

4.2 The (44) ______________ shall be responsible for documenting and/or investigating those incidents not investigated by the (45) ______________.

4.3 The investigation shall address at least the following:

4.3.1 Description and service history of the failed facility or equipment.

4.3.2 Sequence of events leading up to the accident or failure.

4.3.3 General data on any systems involved.

4.3.3.1 Facility specifications.
4.3.3.2 Operating conditions at the time of failure or accident.
4.3.3.3 Physical damage to any facilities or equipment.
4.3.3.4 Physical evidence should be maintained in its original state as much as possible.

4.3.4 Injury to Company and/or third party individuals.

4.3.5 Cause of accident or failure. Conduct laboratory analysis if appropriate. Laboratory metallurgical analysis of the failed specimens may be performed by independent testing/consulting laboratory services.

Ensure the lab selected for analysis follows PHMSA guideline, "Metallurgical Laboratory Failure Examination Protocol." These protocols are attached at the end of this procedure.

4.3.6 Measures to be taken to prevent recurrence, based on final findings.

4.3.7 A review of employee activities to determine whether appropriate procedures were followed.

4.3.8 Procedural changes desirable.

4.4 Any accident investigation by the DOT shall receive full cooperation by the (46) ______________.

5. PROCEDURE

5.1 Responsibilities of the (47) ______________:

5.1.1 In the event of a failure or incident, take appropriate action to protect people first and then property per the applicable emergency plan. (See system specific Emergency Plan if required.)

5.1.2 Secure the site and maintain it undisturbed if possible. If possible, leave failed equipment or portions of failed systems undisturbed, until the appropriate Company representative is on site. If the site or equipment cannot be left undisturbed, thoroughly document the situation prior to disturbing it. Documentation may include such things as taking photographs, making dimensioned sketches and corrosion surveys, collecting soil and liquid samples, as applicable so that the location and orientation of equipment or failed portion can be identified later and other necessary data is not lost by repair work.

5.1.3 Provide for the selecting, collecting, preserving, labeling and handling of metallurgical specimens. Precautions must be exercised to prevent the changing of any sample(s) from its natural state. See 5.2.2 below. Use form 1.03C (chain of custody) or equivalent to ensure samples are properly handled and delivered without tampering.

5.1.4 Arrange for interviews of employees and witnesses as requested.

5.1.5 As soon as possible, but no later than 32 hours after a DOT reportable accident, drug test each employee or contractor's employee whose performance contributed to or may have contributed to the incident. All reasonable steps must be taken to test such persons even though injured, unconscious, or otherwise unable to evidence consent. Reference Part 199.11.

5.1.6 As soon as practicable following a DOT reportable accident, alcohol test each employee or contractor's performance of a covered function contributed to the accident or cannot be completely discounted as a contributing factor to the accident. Reference Part 199.225.

5.2 Responsibilities of the (48) ______________:

5.2.1 On a case by case basis provide on-site investigation of incidents meeting one of the Accident Criteria in Procedure 1.01.

5.2.2 Arrange for outside professional services to assist in an investigation (e.g., corrosion specialist, land surveyor, metallurgist, welding engineer, etc.) if deemed necessary, or if so directed by Legal staff or (49) ______________.

5.2.3 Analyze field data collected, operating history of facility and results of lab testing to establish cause of failure or condition and write reports as necessary.

5.2.4 Provide recommendations for operational changes or facility modifications as appropriate to minimize the possibilities of recurrence.

5.2.5 Written recommendations shall be reviewed by Legal staff and the (50) ______________ prior to issuance.

5.2.6 Submit copies of reports to other agencies and to the applicable Company Offices.

5.3 A critique of the response may be conducted by completing the Company's "Accident and Near Miss Investigation Report – Form 1.03A" or equivalent.

5.4 Follow the company root cause analysis procedures and the guideline above to investigate the failure.

6. RELATED PROCEDURES

6.1 1.01 Reporting and Control of Accidents
1.02 Reporting of Safety Related Conditions
3.04 Preparation of an Emergency Plan
5.01 Continuing Surveillance
Company Root Cause Analysis Procedures

7. RECORDS

7.1 Complete PHMSA Form 7001-1 (Hazardous Liquid Pipeline Systems Accident Report Form) and if appropriate Form 1.01B (located in the forms section), as required. Complete the Company's "Accident and Near Miss Investigation Report"; Form 1.03A or equivalent and root cause analysis forms, if any. Also, use chain of custody form #1.03C if any material is transported from the site.

7.2 The (51) ______________ shall maintain the official files on incidents that are reported to outside agencies.

7.3 Each file shall be kept for the life of the system.

7.4 All records shall be accessible to a representative of the DOT.

Primary Ref: 49 CFR 195.1, 195.2, 195.9, 195.11, 195.12	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.1, 195.2, 195.9, 195.11, 195.12, PHMSA Jurisdictional Review Flowchart, Ca. Gov. Code 51010 and 51011.

2. PURPOSE

The purpose of this procedure is to establish responsibilities for the determination of regulated hazardous liquid pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (57) _______________ is responsible to provide information required by the DOT/OPS and the California State Fire Marshal (CSFM), and to determine which systems are jurisdictional, when appropriate.

4. REGULATED LINES

All pipeline facilities involved in the intrastate, interstate, or international transportation of hazardous liquids, including facilities on the Outer Continental Shelf, are regulated, with the exception of those listed below in paragraph 5 of this procedure.

5. NON-REGULATED LINES

Current Federal definitions are more stringent than current State of California definitions. Therefore, until the next revision of the CSPA (California State Pipeline Act), the Federal non-regulated pipelines are defined as:

5.1 A pipeline for the transportation of a hazardous liquid in a gaseous state.

5.2 A pipeline for the transportation of a hazardous liquid that operates by gravity.

5.3 A non-HVL (highly volatile liquid) low-stress pipeline, except:

5.3.1 In an onshore area other than a rural area;

5.3.2 Offshore; or

5.3.3 In a waterway that is navigable in fact and currently used for commercial navigation.

5.4 A low-stress pipeline that:

5.4.1 Is subject to safety regulations of the U.S. Coast Guard

5.4.2 Serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than 1 mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation.

5.5 Transportation of petroleum in onshore gathering lines in rural areas except gathering lines in the inlets of the Gulf of Mexico.

5.6 Offshore pipeline transporting a hazardous liquid located upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.

5.7 Transportation of hazardous liquid in OCS (Outer Continental Shelf) pipelines which are located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

The specific point(s) where operating responsibility transfers, must be identified on all respective pipelines. The point of transfer must be marked either physically or in the case of a subsea transfer, on a pipeline schematic.

5.8 Pipelines transporting hazardous liquids through onshore production (including flow lines), refining, or manufacturing facilities, and associated storage facilities.

5.9 Transportation of a hazardous liquid by vessel, aircraft, tank, truck, tank car, or other non-pipeline mode of transportation, or through terminal facilities used exclusively to transfer hazardous liquids between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. This does not include any device and associated piping necessary to control pressure so that the MOP is not exceeded.

6. GENERAL

6.1 The CSFM currently acts as an agent of the DOT in enforcing federal and state regulations for all regulated intrastate hazardous liquid pipelines in the State of California. These are pipelines completely within the State of California along their entire length. The state regulations are in Chapter 5.5, "California State Pipeline Safety Act (CPSA) of 1981," of the State of California Government Code. State regulations include all 49 CFR requirements as well as additional state requirements.

6.2 All operators of hazardous liquid pipelines must supply documentation to the CSFM of all their hazardous liquid pipeline systems, including those which seem to be non-regulated. The CSFM shall make the final determination if a system is regulated.

7. PROCEDURE

7.1 The (58) _______________ is to supply the (59) _______________ with system data required to complete the CSFM Pipeline Safety Division Pipeline Operator Questionnaire (see the end of this Procedure) and to update this information as changes occur. This includes all pipeline facilities operated within California.

7.2 The (60) _______________ shall make an initial review of all pipeline facilities to determine what facilities are regulated based on the criteria in Paragraphs 4 and 5 of this procedure.

7.3 The (61) _______________ shall prepare a written report documenting the review process.

7.4 The (62) _______________ is responsible for submitting the Pipeline Operator Questionnaire to the CSFM Pipeline Safety Division, as required. This form must be submitted for existing lines not previously reported to the CSFM, existing lines where changes have occurred since the last submittal, and all new hazardous liquid pipelines. Once a line has been reported to the CSFM, the Pipeline Operator Questionnaire is re-submitted only as changes occur. The Pipeline Operator Questionnaire is used by the CSFM to determine regulated lines and to assess fees as provided by Federal and State Statues. The questionnaire is to be mailed to:

CA Department of Forestry & Fire Protection
Office of the State Fire Marshal
Pipeline Safety Division
PO Box 944246
Sacramento, CA 94244-2460

7.5 Once per calendar year, the (63A) ______________ shall review all hazardous liquid pipeline systems for changes in the information contained in the Pipeline Operator Questionnaire. If no changes are forthcoming, no further action is required. If changes have occurred, or if a new line has been put into service, update the questionnaire and send to the CSFM.

7.6 Once per calendar year, the (63B) ______________ shall review all hazardous liquid pipeline systems for changes in operations including the following;

- New PHMSA "usually sensitive areas (USAs)
- Newly construction pipelines
- Relocated pipelines
- Purchased pipelines
- Other events affecting jurisdiction

If no changes are forthcoming, no further action is required. If changes have occurred, use form #1.04A or equivalent and the following documents to verify the new jurisdictional determination.

- Liquid O&M procedure, #1.04, including form #1.04A
- 49 CFR 19.0, 195.1, 195.2, 195.3, 195.6, 195.11, 195.12
- PHMSA Part 195 Jurisdictional Flow Chart (revised Sept 14, 2011)
- Company basic process flow diagram of the pipeline facility involved
- Company maximum operating pressure (MOP) worksheet
- Aerial photo of pipeline with proximity to USA (USA drinking water resource and/or USA ecological resource)

8. <u>REGULATED TRANSMISSION PIPELINES</u>

PHMSA/CSFM jurisdictional regulated hazardous liquid pipeline must follow all the procedures in this O&M plan unless noted otherwise.

9. REGULATED RURAL GATHERING PIPELINES [195.11]

9.1 If the company has regulated rural gathering pipelines as defined by 195.11(a) and listed below, the company must comply with the safety requirements described in 195.11(b) and listed below.

9.2 Definition of rural gathering [195.11(a)]. As used in this section, a regulated rural gathering line means an onshore gathering line in a rural area that meets all of the following criteria—

(1) Has a nominal diameter from 6-5⁄8 inches (168 mm) to 8-5⁄8 inches (219.1 mm);
(2) Is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in § 195.6; and

(3) Operates at a maximum pressure established under § 195.406 corresponding to—

(i) A stress level greater than 20-percent of the specified minimum yield strength of the line pipe; or

(ii) If the stress level is unknown or the pipeline is not constructed with steel pipe, pressures of more than 125 psi (861 kPa) gage.

9.3 Safety requirements for rural gathering [195.11(b)]. The company must prepare, follow, and maintain written procedures to carry out the requirements of this section. Except for the requirements in paragraphs (b)(2), (b)(3), (b)(9) and (b)(10) of this section, the safety requirements apply to all materials of construction.

(1) Identify all segments of pipeline meeting the criteria in paragraph (a) of this section before April 3, 2009. Liquid O&M procedure #1.04 satisfies this requirement.

(2) For steel pipelines constructed, replaced, relocated, or otherwise changed after July 3, 2009, design, install, construct, initially inspect, and initially test the pipeline in compliance with this part, unless the pipeline is converted under § 195.5.

(3) For non-steel pipelines constructed after July 3, 2009, notify the Administrator according to § 195.8.

(4) Beginning no later than January 3, 2009, comply with the reporting requirements in subpart B of this part. See liquid O&M procedure #1.01, 1.02, and 1.03.

(5) Establish the maximum operating pressure of the pipeline according to § 195.406 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. See liquid O&M procedure #8.01.

(6) Install line markers according to § 195.410 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to maintain line markers in compliance with § 195.410. See liquid O&M procedure #5.04.

(7) Establish a continuing public education program in compliance with § 195.440 before transportation begins, or if the pipeline exists on July 3, 2008, before January 3, 2010. Continue to carry out such program in compliance with § 195.440. See liquid O&M procedure #18.01.

(8) Establish a damage prevention program in compliance with § 195.442 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to carry out such program in compliance with § 195.442. See liquid O&M procedure #3.01.

(9) For steel pipelines, comply with subpart H (corrosion control) of this part, except corrosion control is not required for pipelines existing on July 3, 2008 before July 3, 2011. See liquid O&M procedure #6.05.

(10) For steel pipelines, establish and follow a comprehensive and effective program to continuously identify operating conditions that could contribute to internal corrosion. The program must include measures to prevent and mitigate internal corrosion, such as cleaning the pipeline and using inhibitors. This program must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009. See liquid O&M #6.02.

(11) To comply with the Operator Qualification program requirements in subpart G of this part, have a written description of the processes used to carry out the requirements in § 195.505 to determine the qualification of persons performing

operations and maintenance tasks. These processes must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009. See company OQ plan.

9.4 New unusually sensitive areas [195.11(c)].. If, after July 3, 2008, a new unusually sensitive area is identified and a segment of pipeline becomes regulated as a result, except for the requirements of paragraphs (b)(9) and (b)(10) of this section, the company shall implement the requirements in paragraphs (b)(2) through (b)(11) of this section for the affected segment within 6 months of identification. For steel pipelines, comply with the deadlines in paragraph (b)(9) and (b)(10).

9.5 Record Retention [195.11(d)]. The company must maintain records demonstrating compliance with each requirement according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (b)(1) of this section and the records required to comply with (b)(10) of this section, for the life of the pipe.

(2) An operator must maintain the records necessary to demonstrate compliance with each requirement in paragraphs (b)(2) through (b)(9), and (b)(11) of this section according to the record retention requirements of the referenced section or subpart.

10. REQUIREMENTS For RURAL LOW STRESS PIPELINES [195.12]

10.1 General. This section sets forth the requirements for each category of low-stress pipeline in a rural area. This section does not apply to a rural low-stress pipeline regulated under this Part as a low-stress pipeline that crosses a waterway currently used for commercial navigation; these pipelines are regulated pursuant to § 195.1(a)(2).

10.2 Categories. When the company has a rural low-stress pipeline, the company must meet the applicable requirements and compliance deadlines for the category of pipeline set forth in 195.12(c) which is listed below. For purposes of this procedure, a rural low-stress pipeline is a Category 1, 2, or 3 pipeline based on the following criteria:

(1) A Category 1 rural low-stress pipeline:

(i) Has a nominal diameter of 8-5⁄8 inches (219.1 mm) or more;

(ii) Is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in § 195.6; and

(iii) Operates at a maximum pressure established under § 195.406 corresponding to:

(A) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(B) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gauge.
(2) A Category 2 rural pipeline:

(i) Has a nominal diameter of less than 8-5⁄8 inches (219.1mm);

(ii) Is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in § 195.6; and

(iii) Operates at a maximum pressure established under § 195.406 corresponding to:

(A) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(B) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

(3) A Category 3 rural low-stress pipeline:

(i) Has a nominal diameter of any size and is not located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in § 195.6; and

(ii) Operates at a maximum pressure established under § 195.406 corresponding to a stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(iii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

10.3 Applicable requirements and deadlines for compliance. The company must comply with the following compliance dates depending on the category of pipeline determined above:

(1) An operator of a Category 1 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(1) of this Section before April 3, 2009.

(ii) Beginning no later than January 3, 2009, comply with the reporting requirements of Subpart B for the identified segments.

(iii) IM requirements—

(A) Establish a written program that complies with § 195.452 before July 3, 2009, to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with § 195.452.

(B) An operator may conduct a determination per § 195.452(a) in lieu of the one-half mile buffer.

(C) Complete the baseline assessment of all segments in accordance with § 195.452(c) before July 3, 2015, and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before January 3, 2012.

(iv) Comply with all other safety requirements of this Part, except Subpart H, before July 3, 2009. Comply with the requirements of Subpart H before July 3, 2011.

(2) An operator of a Category 2 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(2) of this Section before July 1, 2012.

(ii) Beginning no later than January 3, 2009, comply with the reporting requirements of Subpart B for the identified segments.

(iii) IM—

(A) Establish a written IM program that complies with § 195.452 before October 1, 2012 to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with § 195.452.

(B) An operator may conduct a determination per § 195.452(a) in lieu of the one-half mile buffer.

(C) Complete the baseline assessment of all segments in accordance with § 195.452(c) before October 1, 2016 and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before April 1, 2014.

(iv) Comply with all other safety requirements of this Part, except Subpart H, before October 1, 2012. Comply with Subpart H of this Part before October 1, 2014.

(3) An operator of a Category 3 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(3) of this Section before July 1, 2012.

(ii) Beginning no later than January 3, 2009, comply with the reporting requirements of Subpart B for the identified segments.

(A)(iii) Comply with all safety requirements of this Part, except the requirements in § 195.452, Subpart B, and the requirements in Subpart H, before October 1, 2012. Comply with Subpart H of this Part before October 1, 2014.

10.4 Economic compliance burden.

(1) An operator may notify PHMSA in accordance with § 195.452(m) of a situation meeting the following criteria:

(i) The pipeline is a Category 1 rural low-stress pipeline;

(ii) The pipeline carries crude oil from a production facility;

(iii) The pipeline, when in operation, operates at a flow rate less than or equal to 14,000 barrels per day; and

(iv) The operator determines it would abandon or shut-down the pipeline as a result of the economic burden to comply with the assessment requirements in § 195.452(d) or 195.452(j).

(2) A notification submitted under this provision must include, at minimum, the following information about the pipeline: its operating, maintenance and leak history; the estimated cost to comply with the integrity assessment requirements (with a brief description of the basis for the estimate); the estimated amount of production from affected wells per year, whether wells shall be shut in or alternate transportation used, and if alternate transportation shall be used, the estimated cost to do so.

(3) When an operator notifies PHMSA in accordance with paragraph (d)(1) of this Section, PHMSA shall stay compliance with §§ 195.452(d) and 195.452(j)(3) until it has completed an analysis of the notification. PHMSA shall consult the Department of Energy, as appropriate, to help analyze the potential energy impact of loss of the pipeline. Based on the analysis, PHMSA may grant the operator a special permit to allow continued operation of the pipeline subject to alternative safety requirements.

10.5 Changes in unusually sensitive areas.

(1) If, after June 3, 2008, for Category 1 rural low-stress pipelines or October 1, 2011 for Category 2 rural low-stress pipelines, an operator identifies a new USA that causes a segment of pipeline to meet the criteria in paragraph (b) of this Section as a Category 1 or Category 2 rural low-stress pipeline, the operator must:

(i) Comply with the IM program requirement in paragraph (c)(1)(iii)(A) or (c)(2)(iii)(A) of this Section, as appropriate, within 12 months following the date the area is identified regardless of the prior categorization of the pipeline; and

(ii) Complete the baseline assessment required by paragraph (c)(1)(iii)(C) or (c)(2)(iii)(C) of this Section, as appropriate, according to the schedule in § 195.452(d)(3).

(2) If a change to the boundaries of a USA causes a Category 1 or Category 2 pipeline segment to no longer be within one-half mile of a USA, an operator must continue to comply with paragraph (c)(1)(iii) or paragraph (c)(2)(iii) of this section, as applicable, with respect to that segment unless the operator determines that a release from the pipeline could not affect the USA.

10.6 Record Retention. The company must maintain records demonstrating compliance with each requirement applicable to the category of pipeline according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (c)(1)(i), (c)(2)(i) or (c)(3)(i) of this Section for the life of the pipe.

(2) Except for the segment identification records, an operator must maintain the records necessary to demonstrate compliance with each applicable requirement set forth in paragraph (c) of this section according to the record retention requirements of the referenced section or subpart.

11. RELATED PROCEDURES

1.01 Annual Reporting
1.02 Reporting of Safety Related Conditions
1.03 Investigation of Failures and Accidents
1.07 HCA Survey
1.08 PHMSA OPID

12. RECORDS

Retain CSFM Pipeline Operators Questionnaire and any jurisdictional determinations for the life of the pipeline facilities.

PIPELINE ANNUAL REPORTS
Hazardous Liquid Pipeline O&M Procedure #1.05

Primary Ref: 49 CFR 195.49	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.49, Ca. Code of Regulations 19, section #2041,and CSFM Annual Questionnaire.

2. PURPOSE and SCOPE

   The purpose of this procedure is to establish responsibilities for preparing and submitting of pipeline annual reports.

   This scope of this procedure applies to all pipelines subject to this part and, beginning January 5, 2009, applies to all rural low-stress hazardous liquid pipelines. An operator of a rural low-stress pipeline not otherwise subject to this part is not required to complete Parts J and K of the hazardous liquid annual report form (PHMSA F 7000–1.1) required by §195.49 or to provide the estimate of total miles that could affect high consequence areas in Part B of that form.

   Beginning no later than June 15, 2005, the company must annually complete and submit DOT form PHMSA F 7000–1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Operators are encouraged, but not required, to file an annual report by June 15, 2004, for calendar year 2003.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (64) ____________________ is responsible to provide information required to fill out the pipeline annual report. The (65) _______________________ is responsible for reporting and documentation of pipeline annual reports for pipeline facilities.

   The (66) _________________________ is responsible for communicating information and data to State and Federal Agencies when additional request are made regarding pipeline annual reports of transmission and gathering pipeline facilities.

4. PHMSA REPORT SUBMISSION REQUIREMENTS [195.58]

4.1 Except safety-related condition report (§191.25) or an offshore pipeline condition report, the company must submit each report required by this procedure electronically to the Pipeline and Hazardous Materials Safety Administration at *http://opsweb.phmsa.dot.gov* unless an alternative reporting method is authorized in accordance with requirements below.

4.2 ***Exceptions***. The company is not required to submit a safety-related condition report (§195.56) or an offshore pipeline condition report (§195.67) electronically.

4.3 ***Alternative Reporting Method***. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA shall review the request and may authorize, in writing, an alternative reporting method. An authorization shall state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

5. PHMSA REPORT SUBMISSION DEADLINE [195.49]

5.1 For each transmission or gathering pipeline system the company must submit an annual report for that system on DOT Form PHMSA 7100-1.1. This report must be submitted each year, not later than June 15, for the preceding calendar year.

A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state.

6. CSFM REPORT SUBMISSION DEADLINE [Ca. Code of Regulations 19, section #2041]

6.1 For each jurisdictional transmission or gathering pipeline system the company must submit an annual report for that system on CSFM "Pipeline Operator Questionnaire." This report must be submitted each year, not later than June 15, for the preceding calendar year.

Information of the CSFM pipeline operator questionnaire is used for statistical purposes and in developing the CSFM invoice for the coming fiscal year. In June of each year, the CSFM shall mail the invoices to the name and address supplied in question #2 of the CSFM questionnaire.

6.2 For questions on the questions, contact CSFM at (916) 445-8477.

6.3 Mail CSFM questionnaire to the following:

Office of the State Fire Marshall
Pipeline Safety Division
PO Box 944246
Sacramento, California 94244-2460

7. PROCEDURE

7.1 District Engineering responsibilities include the following:

Collect data information, such as number and type of leaks, cause of the leaks and their disposition, etc., for preparation and submitting of the Pipeline Annual Reports.

In order to improve the accuracy of reported data, operators are to review successive years' reports in order to validate that their reported numbers are accurate, or to identify and correct inconsistencies or errors that are either found or that may exist in any previously reported data, filing supplemental reports as necessary.

For intrastate Pipelines, and in states where the state is an Agent for DOT, a report shall be submitted by the (67) ___________ in duplicate to the State agency, if the regulations of that agency require submission of these reports, and provide for further transmittal of one copy no later than June 15, to the Information Resources Manager.

8. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
1.03 Investigation of Failures and Accidents
4.01 Class Location Survey and Determination

9. RECORDS

8.1 The District Office shall maintain the official files on Pipeline Annual Reports.
8.2 Each file shall be kept for the life of the pipeline facilities.

NATIONAL PIPELINE MAPPING SUBMITTAL
Hazardous Liquid Pipeline O&M Procedure #1.06

Primary Ref: Pipeline Safety	**Updated: Jan 2016**

1. REFERENCE

Pipeline Safety Improvement Act of 2002, PHSMSA Advisory ADB-08-07, and NPMS Operators Standards Manual.

2. PURPOSE

The purpose of this procedure is to establish responsibilities and requirements for the submittal and updates to the National Pipeline Mapping System (NPMS).

3. RESPONSIBILITY FOR IMPLEMENTATION

The (67) _______________ is responsible to provide information required by the Pipeline Hazardous Materials Safety Administration (PHMSA) and the California State Fire Marshal (CSFM), and to determine which systems are jurisdictional, when appropriate.

4. LINES REQUIRING SUBMITTAL:

4.1 Only PHMSA jurisdictional liquid transmission pipelines are required to submit information to NPMS. This includes jurisdictional hazardous liquids transmission and gathering pipelines as described in the NPMS Operators Standards Manual, pages 14-16.

5. GENERAL REQUIREMENTS AND ANNUAL UPDATES

5.1 Initial information shall be submitted for each jurisdiction liquid transmission pipeline upon startup of a new pipeline, acquisition of a new pipeline, relocation of an existing pipeline, or change in jurisdictional determination from non-jurisdictional/jurisdictional gathering to jurisdictional transmission.

5.2 Annually, between January 1st and June 15th of each year, the company shall submit updates to the NPMS for conditions along the pipeline at the end of the previous calendar year.

5.3 If there are no changes, the company must still notify the NPMS National Repository if there have been no changes from the previous submission. This can be accomplished by emailing to: npms-nr@mbakercorp.com

6. PHMSA NPMS SUBMITTAL PROCEDURE

6.1 Obtain user name and password through the NPMS website listed below.

http://www.npms.phmsa.dot.gov/

6.2 Gather data and meta data and submit in the format required by the NPMS Operator Standards (January 2011) available on the NPMS website.

6.3 For problems or questions, contact the National Repository by emailing npms-nr@mbakercorp.com or calling 703-317-6294.

7. CSFM MAPPING SUBMITTAL PROCEDURE

6.1 Obtain "CSFM State Pipeline Mapping System Operator Submission Standards" (2007) at the website listed below.

http://osfm.fire.ca.gov/pipeline/pipeline_mapping.php

6.2 Gather data and complete Meta data information. Develop shapes files as required by the standard and then submit in the format required by the CSFM standards.

The standards for the State Pipeline Mapping System reflect those of the National Repository standards. There are three small deviations between the systems as shown below.

1) The state system requires age of the pipeline
2) The state system requires the diameter of the pipeline
3) The state system has a positional accuracy standard goal of + 100 feet rather than the national + 500 feet.

Finally, the state system is NOT requiring natural gas lines or liquefied natural gas facilities, only jurisdictional gathering and transmission liquid pipelines.

6.3 For problems or questions, contact the CSFM contact as shown below.

Lisa Dowdy
Office of the State Fire Marshal
Pipeline Safety Division
PO Box 944246
Sacramento, CA 94244-2460
lisa.dowdy@fire.ca.gov

8. RELATED PROCEDURES

1.05 Pipeline Annual Reports

9. RECORDS

9.1 The District Office shall maintain the official files on the company intranet.

9.2 Each file shall be kept for the life of the pipeline facilities.

HIGH CONSEQUENCE AREA SURVEY
Hazardous Liquid Pipeline O&M Procedure #1.07

Primary Ref: 49 CFR 195.452	**Updated: Jan 2016**

1. REFERENCE

   49 CFR 195.452(d)(3), PHMSA IMP Protocols, PHMSA IMP FAQ #1.4 and #3.9.

2. PURPOSE

   The purpose of this procedure is to establish responsibilities for annual review of the company pipeline systems to determine if there any new high consequence areas (HCAs).

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (68) _____________________ is responsible for implementing this procedure.

4. LINES REQUIRING REVIEW:

   4.1 PHMSA jurisdictional hazardous liquid gathering and transmission pipelines are required to review their pipeline systems for potential HCAs.

5. GENERAL REQUIREMENTS AND ANNUAL REVIEWS

   5.1 Annually the company shall reviews its pipeline systems, any acquisitions of new pipeline systems, and any newly constructed pipeline systems for potential HCAs.

   5.2 Even if there are no HCAs or no changes to the pipeline systems, the company must still document this HCA review annually.

   5.3 A newly-identified HCA shall be incorporated into the integrity management program within one calendar year, not to exceed 18 months of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within five years of its identification.

6. PROCEDURE FOR ID of HCAs [195.452(d)(3)]

   6.1 The company shall conduct and HCA survey once per calendar year, not to exceed 18 months, using method described below.

   6.2 Specifically, the company shall use GIS analysis and NPMS review as described below.

GIS Analysis & NPMS Review

The rule defines a High Consequence Area as a high population area, any other populated area, an unusually sensitive area, or a commercially navigable waterway. The Office of Pipeline Safety (OPS) shall map these areas on the National Pipeline Mapping System (NPMS). The company shall use one or more of the following to determine if a pipeline segment affects an HCA.

1) Field survey of the pipeline

2) View and download the data from the NPMS home page *http://www.npms.phmsa.dot.gov.*

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

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

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

The company shall use ESRI mapping, or equivalent software, with PHMSA HCA overlays to determine which segments or pipelines shall affect HCAs.

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

Using GIS information the Company submitted maps of its jurisdictional pipelines under the requirements of the National Piping Mapping System (NPMS) and December 17, 2002 Pipeline Safety Act. The Company shall update the NPMS once per calendar year on or before June 15th of each year.

Using GIS information the Company may also use Google Earth to supplement the HCA survey. Date of Google Earth map shall be included when in the IMP records when used.

Factors in Determining If a Segment Could Affect an HCA

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

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

Technical Justification for Exceptions When Pipeline is in a HCA

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

1. Guidance for performing an analysis to substantiate the conclusion that a pipeline segment located within an HCA could not affect the HCA.

An adequate level of rigor specified for any analysis that is used to justify the conclusion that a segment located in an HCA could not affect the HCA.

A valid analysis to justify the conclusion that a pipeline segment located within an HCA could not affect the HCA. The company's analysis shall consider the following factors:

- HVL properties
- Topographical considerations
- HCA properties

Release Locations

When analyzing the potential affects a pipeline failures that could affect HCAs the company shall define the potential locations on the pipeline where release could occur. The following factors shall be considered and defined and documented with reasons for defining release locations:

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

Spill Volumes

When analyzing the potential affects a pipeline failures that could affect HCAs the company shall define the volume of commodity that could be release in the event of a failure. The following factors shall be considered, defined, and documented with reasons for defining release volumes:

- Failure hole size
- Operating conditions (flow rate, operating pressure)
- Leak detection and response time
- Calculations of drain down following leak or rupture
- Release rate estimates, if air dispersion of vapor clouds is a transport mechanism that is applicable
- Pipeline system design factors (pipe diameter, distance between isolation valves, location of tanks and other facilities)

If the company uses a buffer zone, then the basis for buffer zone distance shall be defined and documented. This documentation shall include the identification of the endpoints of segments that could affect an HCA.

Consideration of Company Work Areas [FAQ #3.23]

The Company shall review it's own work areas according to FAQ #3.23 shown below.

The integrity management rule states that "other populated areas" are included in the definition of high consequence areas. "Other populated areas" are defined in 195.450 as "a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial areas." If the Census Bureau delineates work camps or other areas containing concentrations of an operator's personnel as a Census Designated Place (treated as "other populated areas" in the HCA definition), they are clearly covered under the rule.

Section 192.452(d)(3)(i) also requires that "When information is available from the information analysis…or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a … other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area…." Thus, operators who are aware that work camps or other concentrations of their employees would meet the definition of other populated areas must also treat them as high consequence areas, regardless of whether they are listed on Census Bureau or NPMS maps.

8. RELATED PROCEDURES

1.04 Pipeline Annual Reports

9. RECORDS

9.1 Each file shall be kept for five years.

PHMSA OPERATOR OPID
Hazardous Liquid Pipeline O&M Procedure #1.08

Primary Ref: 49 CFR 195.64	**Updated: Jan 2016**

1. REFERENCE

49 CFR 195.64, PHMSA Advisory ADB-12-04

2. PURPOSE

The purpose of this procedure is to establish responsibilities for obtaining Pipeline Hazardous Materials Safety Administration (PHMSA) operator identification numbers.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (69) _____________________ is responsible for implementing this procedure.

4. LINES REQUIRING PHMSA OPID:

4.1 Effective January 1, 2012 all PHMSA jurisdictional hazardous liquid transmission and gathering pipelines and are required to obtain PHMSA operator identification number (OPID).

5. GENERAL REQUIREMENTS AND ANNUAL REVIEWS

5.1 An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility

6. PROCEDURE FOR OBTAINING PHMSA OPID

6.1 ***To obtain on OPID***, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline Operators in accordance with §195.64.

6.2 ***OPID validation***. An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline Operators at *http://opsweb.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

6.3 ***Changes***. Each operator of a hazardous liquid pipeline or hazardous liquid pipeline facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov* of certain events.

An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

- Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;
- Construction of 10 or more miles of a new pipeline; or

An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

- A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
- A change in the name of the operator
- A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, or pipeline facility;
- The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 195 of this subchapter;

6.4 ***Reporting***. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

7. RELATED PROCEDURES

1.05 Pipeline Annual Reports

8. RECORDS

8.1 Each record shall be kept for five years.

RECORD KEEPING
Hazardous Liquid Pipeline O&M Procedure #2.01

Primary Ref: 49 CFR 195.266, 195.404	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.266, 195.402(c)(1), and 195.404, and CSPA 51015.

2. PURPOSE

The purpose of this procedure is to establish procedures for maintaining records as for time period described by this procedure. In some instances, this shall be for a designated time frame and for other records this shall require maintaining records for as long as the system remains in service.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (68) _______________ is responsible for proper documentation and filing of all records.

4. GENERAL

4.1 The company shall make all construction records, maps, and operating history available as necessary for safe operation and maintenance. [195.402(c)(1)]

4.2 49 CFR 195.404 (a) requires that current maps and records be maintained on regulated pipeline systems that include at least the following information:

Location and identification of the following pipeline facilities:

- Breakout tanks
- Pump stations
- Scraper and sphere facilities
- Pipeline valves
- Cathodically protected facilities
- Facilities not equipped to fail safe that are located in areas that would require immediate response to prevent hazards to the public if the facilities failed or malfunctioned, or that control receipt and delivery of hazardous liquid.
- Rights-of-way
- Overpressure safety devices
- All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines
- The maximum operating pressure (MOP) on each system

- The diameter, grade, type, and nominal wall thickness of all pipe.

4.3 49 CFR 195.404 (b) requires that daily operating records be kept for at least 3 years that include:

4.2.1 Pump station discharge pressure.

4.2.2. Any emergency or abnormal operation.

4.4 49 CFR 195.404 (c) requires that the following records be kept for the periods of time specified:

4.3.1 The date, location, and description of each repair made to pipe. Maintain for the useful life of the pipe.

4.3.2 The date, location, and description of each repair made to parts of the pipeline system other than pipe. Maintain for at least one 1 year.

4.3.3 A record of each inspection and test required by the Operating and Maintenance Procedures of this manual. Maintain for at least 2 years, or until the next inspection or test is performed, whichever is longer.

4.5 CSPA 51015. Requires that the fire department having local fire suppression responsibilities be submitted a map or suitable diagram showing:

4.4.1 The location of the pipeline.

4.4.2 A description of all products transported within the pipeline.

4.4.3 A contingency plan for pipeline emergencies and any reasonable information which the State Fire Marshal may require.

4.6 Specific documentation requirements shall be defined in each related procedure,
and not within this procedure.

5. PROCEDURE

5.1 The (69) _______________ is responsible to see that the records outlined above in Part 4 of this procedure are maintained and that all necessary forms, as required by specific procedures of this manual, are completed and maintained in a permanent record file.

5.2 The (70) _______________ is responsible for:

5.2.1 Initiating any changes to reference maps and specific records, required to keep them up-to-date. Operating and maintenance personnel must be included.

5.2.2 Internal distribution of updated maps and specific records, within the Company, as required. Operating and maintenance personnel must be included.

5.2.3 Providing the local agency having fire suppression responsibilities with updated maps and records containing pipeline location, a description of all products transported within the pipeline, and the system Emergency Response Plan.

5.3 Retain all studies, reports, checks of monitoring devices, and other data for the life of the facility, or as long as the pipeline remains in service, at the District Office.

6. RELATED PROCEDURES

6.1 All procedures in this Manual.

7. RECORDS

Maintain maps containing the information in Part 4.1 and 4.2 of this procedure. Specific documentation requirements shall be defined in each related procedures and is also noted in table #2.01A below.

Record Keeping Tables

Index Description:

Each relevant subpart in 49 CFR 195.266 & 192.404 is divided into colored sections as shown in detail in the index on the following pages. A summary table is shown below:

Description:	Regulation:	Color:
Miscellaneous Reports and Documents	191, 199	Blue
Pressure Testing	195.300-308	Green
Operations and Maintenance	195.400-446	Red
Record Keeping	195.507	Yellow
Corrosion	195.551-589	Orange

Process:

The appropriate person, as defined in the pipeline O&M manual, shall generate the record for work performed. All records for reports, corrosion, operations, maintenance, construction, repairs, and operator qualification shall be routed through the Pipeline Supervisor or DOT Pipeline Advisor for review and signature. These records shall then be placed into the DOT filing system as directed by the Pipeline Supervisor or DOT Pipeline Supervisor. Only files directed by the Pipeline Manager shall be allowed to be shipped to long term storage or destroyed.

Record Retention:

Each record shall be retained for the time noted on the file index. Generally, routine operations, maintenance, and operator qualification records shall be kept for a <u>minimum of five years</u>. Construction, repair, and corrosion records shall be kept for the <u>life of the pipeline</u>. File folders with a red dot indicate the file shall be kept for the life of the pipeline.

Records Location:

Generally, routine operations and maintenance records shall be kept in a pipeline system binder by calendar year. .

Records that require retention for life of the pipeline shall be kept in the appropriate file location as noted in the DOT File Index. New construction, repairs, and other large projects shall be combined into a project binder or file for placement into the DOT filing system.

Primary Ref: 49 CFR 195.266, 195.404 **Updated: Jan 2016**

Misc. Reports & Documents: 49 CFR 191,& 199

	Description	Reg.	Freq.	Record Retention	Record Location
1	Safety Related Condition	191.23	NA	Life of Pipeline	
2	Incident Report (telephone)	191.5	NA	Life of Pipeline	
3	Incident Report (written)	191.15	NA	Life of Pipeline	
4	Annual Report	191.17	Annual	Life of Pipeline	
5	Anti-drug Plan	199.7	NA	5 Years	
6	Random Drug Testing of Employees	199.11	Annual	5 Years	
7	Verification of Drug Testing for Contractors	199.21	Qtrly*	5 Years	
8	Drug Testing Records	199.23	NA	5 Years	
9	DOT Agency Audits & Correspondence	NA	1x/3yr	5 Years	
10	DOT Misc. Correspondence	NA	NA	5 Years	
11	New Regulation Tracking	NA	NA	5 Years	
12	NPMS Mapping submission	Dec 2002 Pipeline Safety Act	Annual	5 Years	

* Recommended frequency

Corrosion Control: Subpart H 195.551 - 589

	Description	Reg. 195	Freq.	Record Retention	Record Location
1	Cathodic Protection System-Monitor External Corrosion Control	.571 and .573(a) (1)	Annual	Life of Pipeline	
2	Corrosion Control	.573(b) (2) before 12/29/ 2003	5 Yrs	**Life of Pipeline	
3	Corrosion Control	.573(b) (2) beginning 12/29/ 2003	5 Yrs	**Life of Pipeline	
4	Rectifier	.573(c)	6x/yr	Life of Pipeline	
5	Corrosion, Mitigate Internal Corrosion (Coupons)	.579(3)	2x/yr	Life of Pipeline	
6	Monitor Atmospheric Corrosion Control	.583(a)	Onshore-3yrs	Life of Pipeline	
7	Monitor Atmospheric Corrosion Control	.583(a)	Offshore-Annual	Life of Pipeline	
8	CP Maps, Dwgs	.589 (a) (1) (2) (3)(b) (c)	NA	Life of Pipeline	
9	CP Maps, Dwgs	.589 (b)	NA	Life of Pipeline	
10	CP Maps, Dwgs	.589 (c)	NA	Life of Pipeline	

* Recommended Frequency

Pressure Testing: Subpart E 195.300-310

	Description	**Reg. 195**	**Freq.**	**Record Retention**	**Record Location**
1	A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.	.310(a)	NA	Life of Pipeline	
2	The record required by paragraph (a) of this section must include	.310(b)	NA	Life of Pipeline	
3	The pressure recording charts;	.310 (b)(1)	NA	Life of Pipeline	
4	Test instrument calibration data;	.310 (b)(2)	NA	Life of Pipeline	
5	The name of the operator, the name of the person responsible for making the test, and the name of the test company used, if any;	.310 (b)(3)	NA	Life of Pipeline	
6	The date and time of the test;	.310 (b)(4)	NA	Life of Pipeline	
7	The minimum test pressure. The test medium;	.310 (b)(5) (6)	NA	Life of Pipeline	
8	A description of the facility tested and the test apparatus;	.310 (b)(7)	NA	Life of Pipeline	
9	An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts	.310 (b)(8)	NA	Life of Pipeline	
10	Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section; and	.310 (b)(9)	NA	Life of Pipeline	
11	Temperature of the test medium or pipe during the test period.	.310(b) (10)	NA	Life of Pipeline	

Primary Ref: 49 CFR 195.266, 195.404	Updated: Jan 2016

Operations and Maintetance195.400-.446
Subpart -F

	Description	Reg. 195	Freq.	Record Retention	Record Location
1	Update O&M Manual	402(a)	Annual	Until Updated	
2	Emergency Response Training	403(5) (b)	Annual	5 Yrs	
3	Maps and Records	404 (a)(4)(b)(1)(2)	Daily	3 Yrs	
4	Maps and Records	404(c) (1)	NA	Life of Pipeline	
5	Maps and Records	404(c) (2)	NA	1 Yr	
6	Maps and Records	404(c) (3)	NA	2 Yrs	
7	Patrolling	412(a)	26x/yr	*5 Yrs	
8	Patrolling	412 (b)	5 Yrs	*5 Yrs	
9	Valve Maintenance	420(b)	2x/ Yr	*5 Yrs	
10	Overpressure Safety Devices and Overfill Protection Systems	428(a)	2x/Yr	*5 Yrs	
11	Overpressure Safety Devices and Overfill Protection Systems	428(b)	Annual*	*5 Yrs	
12	Inspection of In-Service Breakout Tanks	432(a)	Annual	*5 Yrs	
13	Public Awareness	440(5) (i)	NA	*5 Yrs	
14	Damage Prevention Program	442(c) (3)	NA	*5 Yrs	
15	CPM Leak Detection	444	NA	*5 Yrs	
16	Control Room Management	446(b) (1)(2) (3)(4)	NA	*5 Yrs	

Operations and Maintetance195.400-.446 (cont.) Subpart -F

17	Control Room Management	446(c) (3)(4)	Annual	*5 Yrs	
18	Control Room Management	446(d) (1)(2) (3)	NA	*5 Yrs	
19	Control Room Management	446(e) (2)	Monthly	*5 Yrs	
20	Control Room Management	446(e) (3)	Annual	*5 Yrs	
21	Control Room Management	446(e) (4)	Annual	*5 Yrs	
22	Control Room Management	446(e) (5)	Annual	*5 Yrs	
23	Control Room Management	446(h)	Annual	*5 Yrs	
24	Control Room Management	446(i) (1)(2)	Annual	*5 Yrs	
25	Pipeline Integrity Management in (HCA's)	452(d) (3)(i)(ii)	5 Yrs		
26	Annual Report	195.49	Annual		
27	MAOP	619	NA	Life of Pipeline	
28	Conversion to Service	195.5(c)	NA	Life of Pipeline	
29	Requirements that apply to low stress Pipelines in Rural Areas	195.12(f) (1) ,(c) (1)(i),(c)	NA	Life of Pipeline	

*

Primary Ref: 49 CFR 195.266, 195.404	Updated: Jan 2016

Recordkeeping

	Description	Reg. 195	Freq.	Record Retention	Record Location
1	Recordkeeping	507		5 Yrs	
2	Recordkeeping	507(a) (1)		5 Yrs	
3	Recordkeeping	507(a) (1)		5 Yrs	
4	Recordkeeping	507(a) (2)		5 Yrs	
5	Recordkeeping	507(a) (3)		5 Yrs	
6	Recordkeeping	507(a) (4)		5 Yrs	
7	Recordkeeping	507(b)		5 Yrs	

MARKING AND DOCUMENTATION OF MATERIALS
Hazardous Liquid Pipeline O&M Procedure #2.02

Primary Ref: 49 CFR 195.100, 195.134	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Subpart D, Design of Pipeline Components 195.100 – 195.134.

2. PURPOSE

   To establish requirements for marking and documentation of pipe, valves, flanges, fittings, pressure containing components, and major mechanical equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (77) _______________ is responsible for documentation and proper marking of materials outlined in this procedure.

4. GENERAL

   4.1 Pipe, valves, flanges, fittings and pressure containing components used in non-hazardous fluid service, such as instrument air and potable water, are exempted from the requirements of this procedure.

   4.2 These marking and documentation requirements apply to all PHMSA/CSFM jurisdictional pipelines. See O&M procedures #1.04, Jurisdictional Review.

   4.3 Engine and compressor parts are excluded from the requirements of this procedure. This exclusion does not include valves, flanges, pipe fittings, pipe and similar components used on or with an engine or compressor.

   4.4 Each length of new pipe with a nominal outside diameter of 4 ½ in (114.33 mm) or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. Pipe marking must not damage the pipe or pipe coating.

   4.5 Each valve must be marked on the body or the nameplate, with at least the following: (1) Manufacturer's name or trademark; (2) Class designation or the maximum working pressure to which the valve may be subjected; (3) Body material designation (the end connection material, if more than one type is used); (4) Nominal valve size.

4.6 Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75 (49CFR195 currently referenced edition).

5. PROCEDURES

5.1 Verify that material received is marked as shown on the purchase document and that material received is what was ordered. Review the documentation and verify that information agrees with purchase document requirements and the material markings. Only items, which meet or exceed the purchase document requirements, shall be accepted by the receiving location.

5.2 Maintain purchase document number markings on all applicable inventories until they are installed.

5.3 Maintain the purchase document number and any other appropriate identification markings on the material in a manner that does not damage the material so that the marking remains visible until the material is installed. Review marking as necessary.

5.4 Cross reference mill test reports and fitting certification papers with the purchase order number. All steel pipe must have mill test reports when received and all fittings and other components must have certifications.

6. RELATED PROCEDURES

2.01 Record Keeping
1.04 Jurisdictional Review

7. RECORDS

7.1 Maintain a permanent file of applicable purchase documents, material certifications, and as-built drawings, and material for the life of the facilities.

DAMAGE PREVENTION
Hazardous Liquid Pipeline O&M Procedure #3.01

Primary Ref: 49 CFR 195.2, 195.252, 195.442, 198.37	Updated: Jan 2016

1. REFERENCE

49 CFR, Sections 195.2, 195.252, 195.442, and 198.37(e).
PHMSA Advisory Bulletin #ADB-06-03, Accurately Locating and Marking Underground Pipelines Before Excavation Activities Commence Near Pipelines
California Government Code #4216 from SB 1359, Effective January 1, 2007
Common Ground Alliance (CGA) Best Practices, Version 10.0 (www.commongroundalliance.com)

2. PURPOSE

To establish damage prevention program to minimize damage to the Company hazardous liquid pipeline facilities by excavation activities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (83) _____________________ is responsible for implementation of the damage prevention program.

4. GENERAL

4.1 It is Company intent to include, at a minimum, all regulated onshore and offshore pipelines in its prevention program to prevent damage to pipelines owned by the Company. For California pipeline operations additional requirements are noted with reference to Ca. Gov. Code #4216.

4.2 Federal and state pipeline regulations require that each operator of a buried pipeline have a written program to prevent possible damage to a buried pipeline facility by excavation activities. This procedure, O&M 3.01 "Damage Prevention" satisfies this requirement. For the purpose of this Procedure 3.01, "excavation activities" include:

4.2.1 Excavation

4.2.2 Blasting

4.2.3 Directional drilling and other trenchless technology, which includes, but is not limited to, a variety of cutting, jetting, boring, reaming, and jacking techniques.

4.2.4 Tunneling

4.2.5 Backfilling

4.2.6 Removal of above or below ground structures by either explosive or mechanical means.

4.2.7 Plowing (installation of flexible pipe, such as drain tile, or cable without open trenching).

4.2.8 Other earth moving or earth disturbing activities.

4.2.9 Offshore pipe laying.

5. PROCEDURE

5.1 "One Call" Participation

5.1.1 The Company shall support and participate, which is required by law, in a "one call" system.

5.1.2 Whenever pipelines are included in the geographic boundaries of an operational "one call" system, some activities required in this procedure may be performed by the "one call" system. Periodic confirmation of the procedure requirements that are performed by a "one call" system and subsequently are not carried out by the Company, shall occur to assure correct performance.

5.1.3 See Table 3.01C for a listing of local "One Call" phone numbers.

5.2 Identification of Excavators

The company shall develop, on a current basis, a list of contractors and other persons who are normally engaged in excavation activities in the area in which the pipeline is located. The following shall be used to identify excavators on a current basis:

- The Pipeline Association for Public Awareness (PAPA) shall be used to generate the master list of excavators on an annual frequency.

- Once per year the company shall review One Call records and compare the PAPA excavator list to the One Call list. If any new excavators that are discovered during the review, they shall be added to the current list of excavators. PAPA shall also be notified and asked to add the excavator to the mailing list.
- Any excavators discovered on the pipeline without a One Call shall also be added to the excavator list. PAPA shall also be notified and asked to add the excavator to the mailing list.

5.3 Notification of Excavators and the Public

Provide general notification of the public living in the vicinity of the pipeline and actual notification of the individuals identified in 5.2 above, and make them aware of the damage prevention program and its purpose. Since the company is a member of "One Call", this requirement is satisfied by making notifications to "One Call."

5.4 Receiving and Recording Notices of Planned Excavation Activities

5.4.1 Provide for the receipt of routine notices of planned excavation activities. This can be accomplished by direct telephone communication and/or indirectly through one-call notification systems.

5.4.2 Document all notifications requesting line marking or of excavation activity on a form from the one-call service.

5.4.3 Since the company is a member of "One Call", this requirement is satisfied by responding to "One Call" notifications.

5.5 Responding to Notice of Planned Excavation Activities

5.5.1 Log each notice received and determine if excavation activity shall be conducted in the vicinity of the Company's pipeline. If it is determined that the excavation activity is in the vicinity of the Company's pipeline, then that pipeline must be marked in the field.

5.5.2 Advise the requestor that a Company representative shall be present during excavation activity in the vicinity of the pipeline.

5.5.3 Inform the requester if a Company pipeline is located in the area of the planned excavation activity and tell him when the pipeline shall be marked, what type of marking shall be provided and how to identify the marking.

5.5.4 Since the company is a member of "One Call", this requirement is satisfied by responding to "One Call" notifications.

5.6 Pipeline Location and Marking

5.6.1 Locate and provide temporary marking of the pipeline in areas of conflict where excavation activities are observed, anticipated, or shall occur as indicated by One Call/Dig Alert notification. Provide this temporary marking before excavation begins. Follow "Common Ground Alliance" marking guidelines.

5.6.2 Pipelines must be marked within 48 hours of receipt of notification, unless the notifying party agrees to extend this time, and before any excavation activities begin.

5.6.3 Use temporary flags, stakes, or other more permanent marks, if the type and duration of activity so dictates. The minimum length of pipeline to be marked shall be as required by conditions of the site and job. If practical, locate and mark pipelines when a requester's representative is present.

5.6.4 Bends and other changes of direction need to be marked so that the location of the pipe is clearly delineated.

5.6.5 Mark on straight pipeline sections at intervals required by conditions of the site and job, but not to exceed 100 feet (30 meters) onshore and 1000 feet (305 meters) offshore.

5.6.6 If an outside party is seen approaching or working over the Company's pipeline, immediately notify the excavator that a conflict exists and ask him to delay until the line is located and marked.

5.6.7 Remove stakes and/or flags when the work has been completed.

5.6.8 California law requires notification and onsite meeting to verify location of pipeline or utility if excavation within 10 feet of a "high priority subsurface installation." [Ca. Gov. Code #4216]

High priority subsurface installation is defined as: "High priority subsurface installation" is high pressure natural gas pipeline with normal operating pressures greater than 60 psig, or greater than 6 inches nominal pipe diameter petroleum pipelines, pressurized sewage pipelines, high voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60kv, or hazardous material pipelines that are potentially hazardous to workers or the public if damage occurs. [Ca. Gov. Code #4216.1]

5.6.9 Only a "qualified person" is allowed to conduct subsurface installation locating activities. The regulation defines "Qualified person" as a person who completes a safety training program that meets the requirements of 8 CCR 1509 (Injury Prevention Program) & meets the minimum training guidelines and practices of Common Ground Alliance current Best Practices. Common Ground Alliance requires annual locator training. The company defines qualified person as a person who meets the requirements for locating and marking as specified in the company Operator Qualification Plan. [Ca. Gov. Code #4216.1]

5.6.10 The excavator must notify the pipeline operator or call 911 when the excavator discovers or causes damage to the pipeline installation. [Ca. Gov. Code #4216.1]

5.6.11 Ensure up to date pipeline alignment and as-built drawings are available to the locator. The locator shall not rely solely on maps, drawings, or other written materials to locate pipelines. The locator shall notify the appropriate pipeline operator person when the pipeline alignment and as-built drawings need updates. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.12 The locator shall notify the appropriate pipeline operator person when the pipeline alignment and as-built drawings need updates.

5.6.13 Ensure individuals marking & locating are be familiar with state and local marking requirements, and Common Ground Alliance Best Practices marking guidelines which includes recommended color codes and marking guidelines. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.14 Ensure individuals marking & locating have knowledge, skills, and abilities (as required by OQ Program) to read & understand pipeline alignment and as-built drawings.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.15 Locate and mark accurately before excavation begins. This applies regardless if using own company employees or contractors for marking. Honor marking of existing pipelines or utilities. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.16 Mark all pipelines including laterals. Consider environmental conditions such as rain or snow when selecting marking methods. In areas where the pipelines are curved or make sharp bends to avoid other utilities or obstructions, consider the visibility and frequency of markers. Individually mark pipelines within the same trench.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.17 Facilitate communication during the excavation and make sure excavators have sufficient information about underground pipelines at an excavation site to avoid damage to the pipeline.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.18 Calibrate tools and equipment used for line marking and make sure they are in proper working order. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.19 When pipelines are hit or almost hit during excavation, evaluate the practices and procedures before continuing excavation activities.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.20 When there are reports of third party damage on the pipeline, the company shall check the TPD against One-Call tickets and document this review. [PHMSA protocol 195.442]

5.6.21 The company shall review "One-Call" reports and generate a list of third parties who actually conducted excavation activities along the pipelines. These companies who conducted excavation activities shall be included in the public awareness education program either by mailing of materials or onsite visit. This excavation activities list shall be documented once per year including how excavation companies were contacted. [PHMSA protocol 195.442]

5.7 Inspection and Monitoring of Excavation Activities

5.7.1 A Company representative is to be present when excavation occurs that shall expose or may be reasonably expected to expose the pipeline. The (84) ________________ may make other provisions to prevent damage to the pipeline when the excavation activities, such as parallel encroachments, require the representative to be present for long time durations, and there is to be no crossing of the Company's pipeline.

5.7.2 If the pipeline is to be crossed, a Company employee shall determine its depth at the point of intended crossing if practical and necessary. The Company employee shall use a line locator and prodding bar, as appropriate.

5.7.3 Advise the excavator that he may proceed with excavation across the pipeline in a slow and controlled manner, and only if the exact depth and location are known and at least 18" (45.7 cm) of clearance (undisturbed soil) shall exist from the bottom of the excavation to the top of the Company pipeline. Monitor the excavation as it occurs to assure that the depth of excavation is maintained as planned.

5.7.4 If less than 18" (45.7 cm) clearance shall exist from the top of Company pipeline to the bottom of the excavation, or the crossing shall be below the Company's pipeline, prohibit the outside party from approaching the unexposed pipeline closer than 18" (45.7 cm) from the top or 36" (91.4 cm) from the side of the pipeline with mechanical equipment. Require the excavator to expose the pipeline by hand excavation.

5.7.5 Inspection of pipelines must be done as frequently as necessary during and after activities to verify the integrity of the pipeline. Form 3.01B should be utilized for reporting purposes.

5.8 Blasting

If blasting occurs and it is determined that there is possible damage, a leakage survey must be done immediately to verify the integrity of the pipeline.

5.9 Horizontal Directional Drilling (HDD) and other Trenchless Technology

Because of the high potential risk associated with HDD and other trenchless technology, the following procedures are in addition to the above stated requirements for normal excavation methods. These additional procedures are to mitigate the risks of damage to Company and other(s) pipelines.

5.9.1 Maximum separation between substructures, when possible, should be designed into the trenchless operation.

5.9.2 The Company must ensure that contractor personnel are following safe practices and are well qualified and experienced in this type of pipeline installation.

5.9.3 Prior to the commencement of any work, a precise and thorough site survey must be done to locate potential conflicts with known existing underground facilities.

Potholes may be required to determine substructure location(s). A knowledgeable substructure owner or representative must be on site at time of exploration (potholing) and actual trenchless operations.

5.9.4 Whenever HDD is proposed within 10 feet (3 meters) of a known substructure, potholes shall be dug, when possible, at a maximum of 25 foot (7.6 meter) intervals to determine the exact location of the drill head during pilot and back reaming operations.

Characteristics of soil, i.e. rock, sand, etc., can affect the alignment of the pilot hole. Stiffness of the pipe can affect the accuracy.

5.9.5 Personnel must monitor location and alignment of the operation constantly with a "walkover" detector. Read the drill head every 10 feet (3 meters) for direction and depth and mark on the surface. If a problem is encountered, the operation must be either altered or shutdown immediately until the problem(s) is resolved. The "drill head" should not be removed in the event of suspected damage or abnormalities. Further damage could be caused.

5.9.6 If necessary, and to ensure additional safety of the HDD operation, it may be necessary to reduce pipeline operating pressure or shutdown the pipeline completely.

5.10 Exposed Pipe

Whenever any buried pipe is exposed for any reason, the company shall examine the pipe for evidence of external corrosion.

If external corrosion requiring remedial action is found, additional investigation circumferentially and longitudinally may be necessary beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

5.11 Backfilling

When a ditch for a pipeline is backfilled, it must be backfilled in manner that:

- Provides firms support under the pipe, and
- Prevents damage to the pipe and pipe coating from equipment or from backfilled material.

6. <u>PROCEDURE FOR ADDITIONAL PREVENTATIVE MEASURES DUE TO THIRD PARTY DAMAGE IF PIPELINE IS COVERED UNDER THE INTEGRITY MANAGEMENT REGULATIONS</u>

6.1 The Company shall implement the following preventive and mitigative requirements regarding threats due to third party damage. These minimum enhancements to the 195.442 required damage prevention program shall include the following with respect to IMP covered segments to prevent and minimize the consequences of a release:

6.1.1) Using qualified personnel for work the Company is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

6.1.2) Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 195.55.

6.1.3) Participating in one-call systems in locations where covered segments are present.

6.1.4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel.

6.1.5) When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE RP-0502-2002 must be conducted.

6.1.6) If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ANSI/ASME B31.8S Section 7.5.

7. RELATED PROCEDURES

3.02 Telephone Answering Services
18.01 Public Education Program
3.05 Crossing of Company Pipelines
5.01 Continuing Surveillance
5.02 Gas Leak Detection Survey with Instrumentation for Pipelines without Odorant
6.04 Internal and External Examination of Buried Pipeline

8. RECORDS

8.1 Record pertinent information on a one-call service. Retain forms for one year from date of last entry. In the event of litigation or other unresolved situations, do not destroy records until they are no longer needed for such situation.

8.2 Complete the Pipeline Maintenance and Surveillance Form (Form 3.01B) or equivalent each time a buried pipeline is inspected, crossed or an above or below grade pipeline is damaged or hit by an outside party. These records are to be retained for at least five years.

"ONE-CALL" PHONE NUMBERS
TABLE 3.01C

NATIONAL ONE CALL

811

CALIFORNIA

Underground Service Alert (USA) – North
(800) 227-2600
(800) 642-2444

Underground Service Alert (USA) – South
(800) 227-2600

TELEPHONE ANSWERING SERVICES
Hazardous Liquid Pipeline O&M Procedure #3.02

Primary Ref: 49 CFR 195.408, 195.442	Updated: Jan 2016

1. REFERENCE

   49 CFR, Sections 195.408 and 195.442.

2. PURPOSE

   To establish minimum requirements for telephone answering capabilities at locations that are not attended on a continuous basis by a Company employee.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (90) ______________ is responsible for arranging the telephone answering capabilities as needed. Provides a system to receive calls from the public and public agencies.

4. GENERAL

   4.1 A Company employee, contract employee, an answering service or a combination of, shall be available to receive notices 24 hours per day.

   4.2 Locations whose numbers have been given to the public for purposes of reporting emergencies or requesting line locations shall be capable of receiving calls at all times.

   4.3 Locations that are periodically unattended shall have the capability of rerouting calls to another location that is attended or to an answering service.

   4.4 Emergency calls taken by contract employees or answering services, must be returned immediately by Company personnel.

5. PROCEDURE

   5.1 Select a method for receiving, rerouting calls to another location or using an answering service.

   5.2 For rerouting calls, call shall be rerouted to the control center that is attended 24 hours a day. Control operators are to follow instructions per 5.4 of this procedure.

5.3 For answering services, engage only professional quality answering services when outside services are required. Answering services are to follow instructions per 5.4 of this procedure.

5.4 Instruct personnel answering incoming call to:

5.4.1 Obtain the caller's name, telephone number, and location. Ask the caller if there is an emergency.

5.4.2 Advise the caller that a Company employee shall return the call.

5.4.3 Record details if the caller insists on leaving a message but remind the caller that a Company employee shall return the call.

5.4.4 Call the Company's designated employee immediately.

5.4 Company specific phone numbers and emergency procedures are maintained in PSOM and/or pipeline emergency plan respectively.

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents
3.01 Damage Prevention Program
3.04 Preparation of an Emergency Plan
3.06 Preparation of a Pipeline Specific O&M
Pipeline Specific Operations and Maintenance (PSOM) manual
Emergency Response Manual

7. RECORDS

7.1 A log of calls answered must be retained for one year from date of last entry. A One-call service form or equivalent may be used for call documentation.

Not currently used	**Updated: Jan 2016**

#3.03

Not currently used

Previous O&M procedure #3.03, public awareness is now PSOM #18

PREPARATION OF A PIPELINE EMERGENCY RESPONSE PLAN
Hazardous Liquid Pipeline O&M Procedure #3.04

Primary Ref: 49 CFR 195.402(E), 403, 408	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.402(e), 403, and 195.408.
   PHMSA Advisory Bulletin 2013-01 (Accident and Incident Notification Time Limit)

2. PURPOSE

   The purpose of this procedure is to establish the requirement for writing an Emergency Response Plan (ERP) to provide a pre-planned response and method of operation to minimize the hazards to the public and environment in the event of a pipeline facility failure or other emergency.

   This procedure must not be considered a system specific ERP in any sense, but only a guideline for writing an ERP. The guidelines written within this procedure may not be inclusive. The ERP manual should be consulted for definitive guideline and technical information for a given pipeline system or segment. Also, this procedure is not a guide for the "Response Plans for Onshore Oil Pipelines" required by 49 CFR 194.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (106) _____________________ is responsible to train the operating personnel and to assure they are knowledgeable of the emergency procedures and verify that the training is effective.

4. GENERAL

   4.1 An emergency is any situation involving Company pipeline facilities which may endanger human life or significant property, or which may affect normal service to customers (if any).

   4.2 The intent of the planning, preparation and training required by this procedure is to assure:

   4.2.1 Prompt receipt of calls and forwarding of emergency messages to designated personnel for evaluation, investigation, and reporting, at any given time.

   4.2.2 Prompt and effective response to any possible emergency with actions taken to protect people first and then property.

4.2.3 Safe and rapid restoration of service to customers (if any).

4.3 An Emergency Response Plan (ERP) and Pipeline Specific Operations Manual (PSOM) must be prepared and distributed prior to commencement of pipeline operations. Both shall be kept at locations where operations activities are conducted. For preparation of a PSOM, please refer to Procedure 3.06.

5. PROCEDURE

5.2 The Emergency Response Plan (ERP) shall cover at least the following Items:

5.1.1 Receiving, identifying, and classifying emergency calls which require immediate response. [192.402(e)(1)]

5.1.1.1 Emergency calls can come from the public, employees, contractors, and/or other sources. A call may be received by the company phone operator or employee, answering service (see Procedure 3.02 within this manual), or a combination of, and must be available 24 hours a day.

The answering service, or anyone other than a company employee, shall obtain the caller’s name and phone number which shall be relayed to the designated “on-call” person. The “on-call” individual shall then contact the caller obtaining the information listed below.

5.1.1.2 Critical information must be obtained from a caller and should include the following:

1) Caller’s name, address, and phone number.
2) Location of incident, accident or emergency.
3) Type of emergency, i.e. escaping gas from leak or rupture, explosion, fire, other.
4) Known injuries/deaths, if any.
5) Any agencies called or on scene: police, sheriff, fire, etc.
6) Any other pertinent information that the caller volunteers or receiver requires.

Log the time and date of the call and to whom the emergency was reported to within the company.

5.1.1.3 The company's designated "on-call" individual shall evaluate the severity of the emergency and determine the priority of action. If necessary, either personnel shall be dispatched to the scene or the "on-call" individual shall do an on-the-scene investigation. Top priority shall be given to the emergency until the situation has been secured. It may be necessary for other individuals and/or agencies to be involved, if not already, other pipeline and utility operators, emergency response people, etc. The decision(s) shall be made by the company's designated individual(s).

5.1.2 Establishing and maintaining liaison with appropriate fire, police, sheriff, Coast Guard, and other public officials at the city, county, state & federal level, and notifying them of pipeline emergencies.

5.1.2.1 Establish and maintain adequate communication and coordinate with them on planned and actual responses.

5.1.2.2 Maintain a current listing of applicable phone numbers.

5.1.2.3 Learn the responsibilities and resources of each applicable organization.

5.1.2.4 Acquaint them with the Company's ability to respond to an emergency.

5.1.2.5 Identify the types of emergencies of which they shall be notified.

5.1.2.6 Plan how they can assist the Company to minimize hazards to life or property.

5.1.3 Prompt and effective response to a notice of each type of emergency, including the following: [192.402(e)(2)]

5.1.3.1 Fire located near or directly involving a pipeline facility.

5.1.3.2 Explosion occurring near or directly involving a pipeline facility.

5.1.3.3 Natural Disaster.

5.1.3.4 Any operational failure causing a hazardous condition.

5.1.3.5 Accidental release of a hazardous substance from a pipeline facility.

5.1.4 The availability of personnel, equipment, tools and materials, as needed at the scene of an emergency. This should include current list of available equipment and services of pipeline contractors located in the vicinity. [192.402(e)(3)]

5.1.5 <u>Actions directed towards protecting people and employees first and then property</u>.

The first employee or individual that arrives on the scene must evaluate the situation/emergency and take every possible precaution with his limited resources and until assistance arrives, to protect the public and property.

5.1.5.1 The individual shall make an initial survey and evaluation of the situation/emergency, noting location, extent of the hazardous area and if there is secondary damage, involvement of others (if any), resources, whether the situation/emergency is due to company facilities or others, or if not, could company facilities become involved or aggravate the situation.

If a pipeline leak or rupture, is there a potential for an explosion and fire? Has it already occurred?

5.1.5.2 An effort must be made to evacuate all buildings and structures of people which are or could be in the danger zone. If others, or bystanders, are at the scene, try to enlist their services and encourage them to assist with the notification and evacuation.

If a fire department is on the scene, or is represented, they may become the lead agency in directing and securing the emergency. It then becomes the responsibility of the company employee(s) to coordinate and assist the lead agency or incident commander in any way possible and to the best of his/her ability.

If a company facility is involved, assistance could mean the closing of valves and stopping and minimizing the gas or liquid source.

5.1.5.3 Upon arriving at the scene and a gas leak or pipeline rupture is discovered and an explosion and fire have not occurred, every effort shall be made to extinguish all open fires and flames. Absolutely no smoking should be allowed. No arcing – sparking devices should be operated!

If vehicles are within the danger zone, they should be shutdown and abandoned. No vehicle should be started or restarted. The above should be done after people have been secured from the area. If a fire department is on the scene, they can wet down areas that could become problems and also assist in preventing accidental ignition.

5.1.5.4 When people and property have been rendered protected as much as possible, the individual shall report to the designated individual/supervisor “on-call” with regard to the status of the situation. At that time, the individual should request further assistance if the situation warrants such.

Ensure that individuals are aware of how to communicate with the “on-call” supervisor or incident commander, if not on-site.

5.1.5.5 Monitor any change in the extent of the hazardous area. This should be done only when the emergency situation has been secured and reduced to the point where it is safe to enter the defined area.

5.1.6 Taking necessary action such as emergency shutdown and pressure reduction of the pipeline system or segment, <u>to minimize immediate hazards to people first and then property</u>. [192.402(e)(4)]

Instructions and guidelines within the ERP should include but not be limited to the following:

5.1.6.1 List the incidents or situation under which shutdown or pressure reduction would be necessary. These could include manmade or natural disasters. Examples are: explosion, fire, pipeline leak or rupture, earthquake, etc.

5.1.6.2 Specific instructions should be written with regard to the shutdown and pressure reduction procedure for each pipeline system and facility. Include drawings, maps and schematics. Include: provisions for notification and coordination of proper authorities; how to obtain emergency assistance from fire, police, sheriff, and medical; and notifying other utility and pipeline operators.

5.1.6.3 ERP must have maps and drawings showing DOT/OPS designated emergency valves (EV's), which would include manual block valves, automatic or remotely operated valves, and blow down valves. Location of valves is extremely important.

These valves must be given a unique number for identification purposes. Number shall be on the maps and drawings, as well as physically on the valve in the field.

P & ID and schematics of pipeline systems and facilities, should also be included and must indicate what section or segment of pipeline would be affected if a given valve is operated.

5.1.6.4 Once shutdown or pressure reduction has been achieved, confirm by monitoring pressure gauges for positive pressure and blow down stacks for gas or liquid flow. Also check isolation valve position indicators. During shutdown, continue to monitor pressure and flow.

5.1.7 <u>During an emergency, make safe any actual or potential hazard to life or property</u>. [192.402(e)(5)&(6)]

The ERP should include provisions for locating and making safe any actual or potential hazards:

5.1.7.1 Pedestrian and vehicular traffic in the area of the incident, situation, or emergency, must be controlled. This can be done by employees, police, sheriff, or other agencies. If control measures are not effective, serious injury or death could occur.

5.1.7.2 Potential ignition sources must be eliminated or minimized. Please refer to paragraph 5.1.5.3 above.

5.1.7.3 Leaking gas or liquid and their migration must be handled with extreme care regardless of the volume. Once found, whether by instrumentation or other means, immediate action must be taken to alleviate the situation. Action could include a simple wrap around pipeline clamp to a complete pipeline shutdown. In any event, and especially in a populous area, the leak must be located, problem exposed, and pipeline repaired to prevent a potentially disastrous situation from occurring.

5.1.7.4 If the leaking substance has migrated to a building or structure, or filled a valve vault, efforts must be made to ventilate the affected area. Extreme care must be taken in ventilating due to the possibility of the mixture entering the explosive range. If at all possible, shutdown the pipeline until the problem is rectified.

5.1.7.5 Determine the full extent of the hazardous area. Please see paragraph 5.1.5.1 above.

5.1.7.6 Monitor for a change in the defined and delineated hazardous area. Please see paragraph 5.1.5.5 above.

5.1.7.7 If the situation is such that agencies are involved, like fire, police, sheriff, and other public officials, all efforts shall be made to coordinate and centralize control. Please see paragraph 5.1.5.2 above.

5.1.8 In the case of failure of a pipeline system transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas. [195.402(e)(8)]

5.1.9 Safely restoring any service outage to others.

5.1.9 Begin investigation of failures as soon as possible, and record all initial investigative results (see procedure 1.03).

5.1.10 Include the name and telephone number of the following personnel or organizations:

5.1.10.1 Personnel at the operating location.

5.1.10.2 Personnel involved in investigation and reporting of emergencies, such as Code Compliance, Public Relations, Safety, etc.

5.1.10.3 Forestry Department

5.1.10.4 Electrical power companies in the area

5.1.10.5 Police and sheriff departments as well as locally based state police

5.1.10.6 Fire departments

5.1.10.7 Ambulance services

5.1.10.8 Hospitals

5.1.10.9 Civil Defense

5.1.10.10 Telephone Companies

5.1.10.11 All other appropriate companies and organizations which may furnish needed equipment.

5.1.11 Procedures to contact the NRC within one hour of discovery of a pipeline incident and their requirement to also file additional telephonic reports if there are significant changes in the number of fatalities or injuries, product release estimates or the extent of damages. [PHMSA Advisory 2013-01, Accident and Incident Notification Time Limit]

5.2 Training

5.2.1 The Company shall establish and conduct a continuing training program. Elements of this training program shall include the following:

- Training the appropriate personnel to assure that they are knowledgeable of the system specific Emergency Response Plan and related procedures.
- Training on the characteristics and hazards of the hazardous liquids being transported. In the case of flammable HVL, training shall be given on flammability of mixtures with air, odorless vapors, and water reactions.
- Training to recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunction or failures, hazard liquid spills, and how to take appropriate action.
- Training on steps necessary to control any accidental release of any hazardous liquid and to minimize the potential for fire, explosion, toxicity, or environmental damage.
- Training on the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment.

5.2.2 Training shall be accompanied through various means: simulated drills, classroom, hands-on, and others. Where feasible, a simulated pipeline emergency drill shall be conducted as the first choice of training.

5.2.2 To verify that training is effective, the Company shall use written test and/or emergency drills.

6. EMERGENCY PLANS REVIEW AND UPDATE

6.1 Immediately following an emergency, employee activities and the activities of others such as contractors, public officials, police, fire, etc., should be reviewed to determine whether the procedures were effectively followed. By reviewing logs and diaries of events and the action taken, and interviewing employees or others, effectiveness of the procedures can be determined. Consideration should be given especially to whether responses to the situation/incident/emergency were timely or not.

6.2 Review the ERP, Platform Operating Procedures (POP) if appropriate, and related procedures periodically with local operating personnel at least once a year, preferably at safety or other group meetings.

6.3 Revise, modify, and update the Emergency Response Plans (ERP and POP) as necessary, or as may be indicated by the experience of an emergency.

6.4 Provide the latest versions of the Emergency Plans to all facilities and so they are readily accessible to all employees.

7. RELATED PROCEDURES

1.01 Reporting and Control of Incidents
1.03 Investigation of Failures and Accidents
3.02 Telephone Answering Services
18.01 Public Education Program
System Specific Emergency Response Plan (ERP), and Platform Operating Procedures (POP)

8. RECORDS

8.1 Document dates, attendance and subject matter of training sessions and meetings.

8.2 Document contacts with public officials. Include dates, Company and public persons involved, subject matter and details of any agreements.

8.3 Document incoming calls to the Company operator or answering service.

8.4 Maintain the above records at least five years.

CROSSING OF COMPANY PIPELINES
Hazardous Liquid Pipeline O&M Procedure #3.05

Primary Ref: 49 CFR 195.250, 195.442	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.250 and 195.442.

2. PURPOSE

   To establish procedures to follow when new or relocated above grade or buried facilities, such as electric power, gas, oil, water, or communication cables are planned to cross Company pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (111) _______________ is responsible to implement the requirements of this procedure when Company pipelines are crossed by foreign operators.

4. GENERAL

   4.1 Whenever possible and practical, parallel pipeline and utility encroachments and the installation of a physical structure, such as an anchor block, tower footing, or alternating current electrical ground system, associated with an overhead transmission facility, should be at least 25 feet (7.6 meters) from Company pipeline.

   4.2 For underground pipeline crossings, a minimum of 12" (30.5 cm) of separation from outside of pipe must be maintained between a foreign facility and a Company pipeline unless the pipeline is specially protected from damage and corrosion control that might result from the proximity of the other facility.

   4.3 Communication cables installed by others should be protected from potential damage by Company maintenance activities. This protection may include burial of the cable below the pipeline and the encasement in a 6" (15 cm) diameter pipe, 15' (4.6 meters) long, or the installation of a 4" (10 cm) thick x 4' (1.2 meters) wide x 10' (3.0 meters) long concrete pad over the cable. Local building codes may require other requirements.

   4.4 Underground electrical cables installed within 10 feet (3.0 meters) on either side of the pipeline, should be placed, if possible, in an insulating conduit or jacket. Cables, if possible, should cross a minimum of 3 feet (0.91 meters) below the pipeline and be encased in red concrete across the entire right of way width.

4.5 It is preferred that all buried crossings be installed under an existing Company pipeline and cross at right angle. If the review of specific job conditions concludes that this requirement is unreasonable or impractical, allowing the crossing above the Company pipeline could be acceptable.

4.6 The leverage by which the Company can force a foreign operator to accept these requirements is dictated primarily by the ownership and/or right of way document governing the pipeline. These document details may include:

4.6.1 Permit

4.6.2 Private Easement (not exclusive)

4.6.3 Exclusive Private Easement

4.6.4 Company Ownership

5. PROCEDURE

5.1 Request that any foreign operators wanting to encroach upon Company facilities supply a written request to do so and include a drawing detailing the proposed installation.

5.2 Review the proposed encroachment for compliance with this procedure and work with the foreign operator to eliminate any conflicts with requirements outline in this procedure.

5.3 Install, as determined by Company or contract cathodic protection personnel where and when practical, a test lead at the point of crossing on the Company's pipeline and insure that the foreign operator also installs a test lead on his facility if the foreign crossing is a metallic structure such as a pipeline, metal sheathed cable, or bare cable.

5.4 Electrically survey Company's pipeline and foreign operator facility to determine if interference exists. If interference is found to exist install the appropriate protective equipment as agreed to by both parties. This may include as follows:

5.4.1 If more than 15 volts A.C. are present, make arrangements with the foreign operator for the installation of a grounding cell, magnesium or zinc anode, on the Company's pipeline and the foreign operator cable.

5.4.2 If interference current flow between structures exists, install a magnesium anode or anodes on the Company's pipeline or require the foreign operator to install one on his facility, if appropriate, as an auxiliary current drain-off point or make arrangements for the installation of resistance bond.

5.5 Do not allow new electrical transmission line construction over existing blow off risers, and keep them as far as practical from the risers.

6. RELATED PROCEDURES

3.01 Damage Prevention Program
6.05 Cathodic Protection/External Corrosion Control
12.03 Pipeline Movement

7. RECORDS

7.1 Form, "Pipeline Maintenance and Surveillance" (Form 3.01B) or equivalent may be used to document any gathered information.

7.2 Keep copies of any gathered information for the life of the pipeline.

7.3 Submit information detailing the crossing to the (112) _______________ for strip map or plat sheet updating.

PREPARATION OF A PIPELINE SPECIFIC OPERATIONS MANUAL
Hazardous Liquid Pipeline O&M Procedure #3.06

Primary Ref: 49 CFR 195.402, 195.408, 195.444	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.402(a), 195.408 and 195.444.

2. PURPOSE

   The purpose of this procedure is to establish the minimum requirements for writing a Pipeline Specific Operations Manual (PSOM) to provide operating and pre-planned response for normal and abnormal pipeline operating conditions.

   This procedure must not be considered a PSOM in any sense, but only a guideline for writing a PSOM. The guidelines written within this procedure may not be inclusive.

   The PSOM should be consulted for definitive guidelines and technical information for a given pipeline system or segment. The facility standard operating procedures (SOP) manual should also be consulted for additional guidelines and information.

3. RESPONSIBILITY FOR ADMINISTRATION

   The (118) ______________ is responsible for the preparation and updates to the PSOM for normal and abnormal conditions. The (119) ________________ is responsible for training operating personnel and to assure they are knowledgeable of the PSOM.

4. GENERAL

   4.1 A written PSOM is required to describe the normal operating status of a specific pipeline system, and to provide safety during operations and maintenance.

   4.2 A written PSOM is required to describe the abnormal operating status of the pipeline and to provide safety when operating design limits have been exceeded.

   4.3 The intent of these plans is to provide a basis for documenting the physical attributes of a pipeline and to facilitate training of operating personnel for a specific pipeline.

   4.4 General Operating and Maintenance Procedures are contained in the Standard Operating and Maintenance Procedures Manual for Hazardous Liquid Pipelines of which this procedure is a sub-part, and shall be used as a basis for preparing the PSOM. As a minimum, the topics contained in this Procedure, 3.06, shall be individually addressed in each PSOM.

4.5 The Emergency Response Plan (ERP) required by Procedure 3.04 of the Standard Operating and Maintenance Procedures Manual for Hazardous Liquid Pipelines, is a separate document.

4.6 A PSOM must be prepared and distributed prior to commencement of pipeline operations. The PSOM shall be kept at locations where operations activities are conducted.

4.7 A written PSOM is required to describe the requirements for control room management procedures to increase the likelihood that the pipeline controllers have the necessary knowledge, skills, and abilities to help them prevent accidents. The regulation and these procedures shall also help ensure that pipeline operating companies provided controllers with the necessary training, tools, procedures, management support, and environment where a controller's actions can be effective in helping assure a safe operation.

5. PROCEDURE

5.1 A PSOM shall have at least two major divisions. One division shall contain information concerning the normal operation of the pipeline. The second division shall contain information relevant to abnormal conditions.

5.1.1 To provide safety during normal operations, the PSOM or POP manual, shall provide at a minimum, the following information:

5.1.1.1 Current and comprehensive construction records, maps, and operating history shall be available for use by operations, engineering, maintenance personnel, and especially individuals involved with safety and emergency response. These documents can be attached to or stored with the PSOM, but shall be available with facility documentation when appropriate, and upon request from the data library.

5.1.1.2 The normal ranges of operating parameters such as pressure, flow, relief pressure settings, alarm settings, and valve positions.

5.1.1.3 The locations of areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned, shall be included. Provisions for minimizing the potential hazards identified at these locations shall also be provided.

5.1.1.4 Provide procedures for the start-up and shutdown of either an existing or new pipeline system, or segment, to assure that the operating parameters and MOP of the pipeline are not exceeded.

5.1.1.4.1 Procedures should include, but not be limited to, the following for pipeline <u>startup</u>:

1) Insuring that all required manuals: O&M, ERP, PSOM, & POP (if required), are in place prior to startup or restart of a pipeline, especially a new pipeline

2) For a new pipeline, inspecting all relief devices such as relief valves, regulators, and rupture disks, and set pressures of relief devices must be checked and recorded as well as volume.

3) Establishing two way vocal communications between the control center and the scene of abnormal operations and emergencies.

4) Conducting a follow-up leak survey, if applicable. (See Procedures 5.01, and 5.03 within this manual for leak surveys).

5) Ensuring that drawings, maps, schematics, and P & ID's, and other operating parameters and records are updated.

6) Utilize manufacturer's instruction manuals and guidelines when appropriate.

5.1.1.4.2 Procedures should include, but not be limited to, the following for pipeline <u>shutdown</u>:

1) Planning, preparation and written procedures for a shutdown. The plan must provide for full control of the content in the system or segment, and any related facilities, at all times during the operation (including the shutdown, down period, and startup).

2) General preshutdown activities which might include: briefings and work assignments, communication, pressure limits, serviceability of valves and other devices, precautions to minimize fire hazards, and doing as much work prior to shutdown as possible.

3) Pipeline content control activity. The individual responsible for this function must ensure that all personnel involved are fully versed in their assignments. Caution must be used to prevent accidental ignition when blowing down or venting. Content pressures in the pipeline must be monitored continuously.

4) Must establish safe hazardous liquid conditions at work-site(s). A procedure must be written to establish a safe working environment whether work is performed on the surface or in an excavation. Include a means of constant monitoring especially if a pipeline is open and residual liquids could be present or released.

5.1.1.5 The PSOM shall address the physical properties of the hazardous liquids, elevations along the pipeline, and location and type of pressure monitoring and control devices.

5.1.1.6 The PSOM shall require attended pressure monitoring during start-up and shutdown unless the pipeline system is designed to fail-safe.

5.1.1.7 Means of detecting abnormal conditions, and monitoring pressure, temperature, flow or the appropriate operational data and transmitting this data to an attended location unless the pipeline system is designed to fail safe.

5.1.1.8 Procedures for pipeline pigging, where applicable.

5.1.1.9 Procedures for corrosion control plan, where applicable.

5.1.1.10 Procedures for draining of pipeline and components such as vessels of liquid. This applies only to regulated portions of the pipeline system.

5.1.1.11 Periodically a review shall be made of personnel's performance to determine if the written procedures for normal operating and maintenance in the PSOM, POP Manual and O&M Manual are adequate and effective, or have deficiencies. Discussions with operating and maintenance personnel could also reveal weaknesses and strengths of the procedures. Any suggestions for changes should be taken under advisement.

Taking into consideration the review and recommendations, the procedures in the manuals should be either modified or rewritten accordingly.

5.1.1.12 Inadequacies and needed changes discovered during discussions and periodic review of personnel conducted according to 5.1.1.11 above, shall be rectified during the Annual Review of the manuals, or as soon as possible if deemed necessary.

It shall be necessary to retrain and acquaint personnel with any changes to the procedures. All training and procedure modifications must be documented. (See 7. Records below).

5.1.1.13 Procedures to ensure protection of personnel from unsafe accumulations of vapor or fumes in excavated trenches. These procedures shall address making available emergency rescue equipment, including breathing apparatus, and a rescue harness. Procedures must be in accordance with Company Confined Space Entry Standards.

5.1.2 To provide safety during incidents where normal pipeline parameters have been exceeded. The <u>abnormal conditions</u> section of the PSOM or POP Manual shall provide at a minimum, the following information:

5.1.2.1 The abnormal operations section shall include sections addressing identification of, responding to, investigating, and rectifying the following situations:

- Unintended opening or closure of valves.
- Increase or decrease of flow rate outside of normal pipeline parameters.
- Increase or decrease of pressure outside of normal pipeline parameters.
- Loss of communications.
- Operation of any safety device.
- Any malfunction of a component or deviation from normal operating parameters or personnel error which could cause a hazard to persons or property.

In addition to considering the type of abnormal conditions listed above, the location where the condition may or could exist (i.e. the proximity to the public, employees, facilities, buildings, and structures) must be considered.

The nature of the condition (i.e. the extent to which it could lead to an emergency situation if not immediately corrected) is another item that must be addressed.

Finally, what the resulting effect would be on the operation of a pipeline system if one of the above listed conditions were to occur.

5.1.2.2 Once an abnormal operating condition has occurred and it has been investigated to determine the cause, and corrective action taken, the pipeline may be returned to service.

The abnormal condition occurrence shall be reviewed to develop measures, if necessary, to prevent the cause of the condition from recurring. If a corrective measure can be applied to the pipeline system or segment in question, it should be considered for implementation in other systems to avoid similar occurrences.

5.1.2.3 Once restarted, provisions for the inspection and monitoring of the pipeline operating conditions and parameters at critical locations along the pipeline, shall be made to ensure continued integrity and safe operation.

Monitoring of the restarted pipeline system or segment, shall continue and be based on the nature of the abnormal condition, severity of the incident and/or emergency, and the probability that the cause of the condition could recur. The cause of the condition is considered corrected when at the end of the monitoring period, the pipeline system or segment has maintained operations within its design limits and parameters.

5.1.2.4 A list of responsible operating personnel to be notified in the event of an abnormal situation shall be included. The list shall include current telephone, radio, pager, or cellular telephone numbers as appropriate.

5.1.2.5 Abnormal conditions that result in emergencies shall be addressed in the system specific Emergency Plan prepared per Procedure 3.04.

5.1.3 An immediate review of personnel’s response to control the abnormal condition, should be conducted based on the extent of the situation/incident/emergency. The review should consider the actions taken, and whether the procedures in the PSOM and/or POP are adequate and effective or have deficiencies that should be modified or rewritten accordingly. In rewriting the procedures, if necessary, specificity or more flexibility should be considered.

5.1.4 Inadequacies discovered in either personnel response or the written procedures shall be considered and rectified as follows:

1) Personnel response – immediately following startup and stabilization or monitoring period of pipeline

2) Procedures – during the Annual review of the manuals, or as soon as possible, if deemed necessary.

Any changes to the procedures shall necessitate the retraining of personnel. All training and procedure modifications must be documented (see 7. Records below).

5.2 Computational Pipeline Monitoring (CPM) leak detection system installed on pipelines transporting hazardous liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, recordkeeping and dispatcher training.

5.3 A written PSOM is required to describe the requirements for control room management procedures to increase the likelihood that the pipeline controllers have the necessary knowledge, skills, and abilities to help them prevent accidents. The regulation and these procedures shall also help ensure that pipeline operating companies provided controllers with the necessary training, tools, procedures, management support, and environment where a controller's actions can be effective in helping assure a safe operation.

The control room management section of the PSOM shall provide at a minimum, the following information:

5.3.1 Roles and Responsibilities: Items that shall be considered when developing the roles and responsibilities for the Control Room and Controllers include the following:

- Determining and defining clearly for the Controllers to know when responsibility and accountability passes from one Controller to another for any normal shift change or other change of duty from one Controller to another.
- Ensuring that Controllers understand their responsibilities and accountabilities.

- These responsibilities and level of authority should be clear for both the pipeline supervisor and Controller.

5.3.2 Tools and Information: The procedures shall describe the minimum tools and information the Controller should have to conduct their job safely.

5.3.3 Fatigue Management and Education: The procedures shall describe how to address in shift work to prevent fatigue and training on how to recognize signs of fatigue.

5.3.4 Alarm Management: The procedures shall include point to point verification under certain conditions, annual review of alarms, alarm activity review, and documentation of alarm deficiencies.

5.3.5 Mangement of Change: The procedure shall include MOC for significant changes as defined by the MOC process.

5.3.6 Operating Experience: The procedures shall include a review and implementation of lesson learned including review of incidents.

5.3.7 Training Program: The procedures shall include a training program for controllers and also a annual training program review.

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents

1.02 Investigation of Failures and Accidents

3.02 Telephone Answering Services

3.04 Preparation of an Emergency Response Plan

7. RECORDS

7.1 Document dates of personnel reviews of normal and abnormal operating plans and revisions required to the plans. These records are to be retained for at least two years.

7.2 Document dates operating personnel training

7.3 The PSOM shall be reviewed at least once each calendar year at intervals not exceeding 15 months, with appropriate changes made as necessary.

7.3.1 Prepare and distribute a new or revised PSOM and document the issue dates.

7.3.2 A list of PSOM revisions should be maintained for the life of the pipeline system.

SCRAPER AND SPHERE FACILITIES
Hazardous Liquid Pipeline O&M Procedure #4.01

Primary Ref: 49 CFR 195.426, 195.120	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Section 195.426, and 195.120.

2. PURPOSE

The purpose of this procedure is to define proper operation and maintenance of scraper and sphere facilities and includes requirements of when repairs or replacements of pipe should allow for passage of internal device.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (130) _______________ is responsible for the proper operation of scraper and sphere facilities.

The (131) _______________ is responsible for the scheduling, conducting, correction, and record keeping of the requirements of this procedure.

4. GENERAL

4.1 Launchers and receivers must be equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres.

4.2 A suitable pressure indicator must be installed on all launchers and receivers to verify that pressure has been relieved in the barrel or, a means to prevent insertion or removal of scrapers or spheres before pressure has been relieved in the barrel must be provided.

4.3 Unless exempted by 195.120(a) and 195.120(c), each new pipeline or replaced pipeline must be designed and construction to accommodate passage of instrumented internal inspection device. 195.120(a) exemptions include manifolds, station piping, cross overs, piping too small for passage of internal device, offshore 10” or less OD. 195.120(c) exemption is for emergency situations including documentation on why impracticable.

4.4 The company shall provide protection for scraper and sphere facility and other exposed facilities from vandalism and unauthorized entry.

5. PROCEDURE

5.1 During atmospheric corrosion inspections, the pipeline operator shall inspect and verify that all launchers and receivers have the capabilities described in Paragraph 4 above. If not, install the appropriate equipment to give them those capabilities.

5.2 During the annual inspection look for evidence of corrosion that would affect the safety of scraper and sphere facilities. If corrosion is found, the company corrosion engineer or designee should be contacted for development of a corrosion mitigation plan. This inspection is designed to detect corrosion before launcher/receiver strength is impaired.

5.3 Inspect pressure relief devices per Procedure 7.02 (once per calendar year not to exceed 15 months).

5.4 Ensure that insertion or removal of inspection devices shall not occur prior to pressure relief in the barrel.

This can be accomplished one of the following:

1) Closure devices similar to the Yale or Tube Turn closure doors that indicate to the operator that pressure remains on the barrel prior to opening the closure, such as "lock and bleed" or pressure warning devices are adequate devices.
2) A fitting capable of accepting a pressure gauge with an isolation valve is adequate for determining that pressure has been relieved, even if the gauge is attached only during trap operations.
3) Drain lines that can clearly indicate there is no pressure on the scraper facility is adequate for determining that pressure has been relieved.

5.5 Each scraper and sphere facility or other exposed facility must be protected from vandalism and unauthorized entry. The company shall use one or more of the following security techniques at pump stations, breakout tanks, and other exposed facilities.

- Security fencing
- Locks on equipment
- Other options may be used if reviewed and documented and described in the PSOM

Vandalism history shall be evaluated during the continuing surveillance reviews and may dictate which security method is prudent. The protection from vandalism provided at each scraper and sphere facility inspected should be adequate to prevent the level of vandalism experienced at the site.

scraper and sphere facility that may be exposed to outside force damage such as vehicular damage should have some type of protection surrounding them. Typically this would be bollards.

6. RELATED PROCEDURES

6.01 Atmospheric Corrosion
6.02 Internal Corrosion
7.02 Pressure Regulators and Relief Devices
9.01 Repair Procedures

7. RECORDS

7.1 Form 7.02A or equivalent may be used for documentation. Retain all records a minimum of five (5) years.

BREAKOUT TANKS
Hazardous Liquid Pipeline O&M Procedure #4.02

Primary Ref: 49 CFR 195.428	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Section 195.1(c), 195.3, 195.132, 195.205, 195.264, 195.307, 195.405, 195.428, 195.430, 195.432, 195.434, 195.436, and 195.438, NFPA 10 (Standard for Portable Fire Extinguishers).

2. PURPOSE

The purpose of this procedure is to establish requirements for the inspection and maintenance of breakout tanks.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (133) ______________ is responsible for the implementation of Operating and Maintenance Procedures for breakout tanks.

The (134) ______________ is responsible for the scheduling, conducting, correction, and record keeping of the inspections and maintenance procedures required by this procedure.

4. GENERAL

4.1 A breakout tank is a tank used to:

4.1.1 Relieve surges in a hazardous liquid pipeline system, or

4.1.2 Receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

4.2 A means of containing hazardous liquids in the event of spillage or tank failure must be provided.

4.3 After October 2, 2000, compliance with 4.2 above requires the following for above-ground breakout tanks specified:

A) For tanks built to API Spec 12F, API Std 620, and others (such as API Std 650 or its predecessor Std 12c) the installation of impoundment must be in accordance with sections of NFPA 30: Section 2-3.4.3.
Impoundment by drainage to a remote impounding area must be installed in accordance with Section 2-3.4.2

B) For tanks built to API Std 2510, installation of impoundment must be in accordance with Section 3 or 9 of API Std 2510.

4.4 The following must be provided for each breakout tank:

4.4.1 Safety devices that prevent over pressurization.

4.4.2 Each breakout tank or other exposed facility must be protected from vandalism and unauthorized entry. The company shall use one or more of the following security techniques at pump stations, breakout tanks, and other exposed facilities.

- Security fencing
- Locks on equipment
- Other options may be used if reviewed and documented and described in the PSOM

Vandalism history shall be evaluated during the continuing surveillance reviews and may dictate which security method is prudent. The protection from vandalism provided at each breakout tank inspected should be adequate to prevent the level of vandalism experienced at the site.

Breakout tanks that may be exposed to outside force damage such as vehicular damage should have some type of protection surrounding them. Typically this would be bollards.

4.4.3 Adequate firefighting equipment. Use NFPA 10 (Standard for Portable Fire Extinguishers) as a guide.

4.4.4 Signs visible to the public with contact information and information warning the public of the hazards. The signs shall contain the name of the company and a telephone number, including area code, where the company can be reached at all times.

The signage shall include prohibiting smoking or open flames where there is possibility of the presence of hazardous liquids or flammable vapors.

Pipeline markers meeting the requirements of §195.410 (line markers), may be used to satisfy this requirement, provided they are located within/on the facility fence or immediately adjacent to the fence. See O&M procedure #5.04, Pipeline Markers and Signs for more details.

4.5 Normal and emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure and vacuum-relieving must be provided for each low-pressure and high pressure breakout tank.

4.6 For normal and emergency relief venting and pressure/vacuum-relieving devices installed after October 2, 2000, the following for the tanks specified shall be used:

A) Tanks built to API Spec 12F, use Section 4 and Appendices B & C of Spec 12F.

B) Tanks built to API Std 650, or its predecessor Std 12, use API Std 2000.

C) Tanks built to API Std 620, use Section 7 of API 620 and its reference to venting in API Std 2000.

D) Tanks built to API Std 2510 (high pressure tanks), use Sections 5 or 9 of API Std 2510.

4.7 Overfill protection system shall be installed on breakout tanks either built or modified after October 2, 2000. Either API 2350 or API Std 2510 must be referenced for this subject.

4.8 Smoking and open flames are prohibited in each breakout tank, pump station, and other exposed facilities.

4.9 After October 2, 2000, protection against ignition arising out of static electricity, lightning, and stray currents during operation and maintenance activities with breakout tanks, must be in accordance with API RP 2003.

4.10 After October 2, 2000, the hazards associated with access/egress onto floating roofs of in service aboveground breakout tanks must be considered when performing inspection, service, maintenance, or specific repair activities. The potentially hazardous conditions must be reviewed and considered along with safety practices and procedures. Refer to 195.405(b) for specific guidelines and references.

5. PROCEDURE

5.1 Implement a corrosion detection program designed to detect corrosion before the tank strength is impaired.

Note: For the bottoms of aboveground breakout tanks with greater than 500 bbls ($79.3m^3$) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor standard 12C, the installation of a cathodic protection system after October 2, 2000 must be in accordance with API RP 651, unless the company can determine or provide reasons otherwise.

For the internal bottom of the above described breakout tank(s), the installation of a tank bottom lining after October 2, 2000, must be in accordance with API RP 652, unless the company can determine or provide reasons otherwise.

The CP system shall also be inspected according to API RP651.

5.2 Inspect overfill protection systems and normal and emergency tank venting systems, where appropriate.

5.3 Any aboveground breakout tank that has been built, repaired, altered, or reconstructed and ultimately returned to service must be pressure tested. Testing must include external loading.

Testing, whether for external loading or fluid loading, must be done under the specification the tank was built and designed to. This would be for any tank built or modified after October 2, 2000. Refer to 49CFR 195.205(b) and 195.307 for specific specifications.

5.4 Frequency of inspections:

#	Description:	Frequency
1.	Pump station discharge pressure	Daily
2.	Fire fighting equipment inspection	Monthly [OSHA requirement]
3.	Fire fighting equipment service	Annual [OSHA requirement]
4.	Monthly inspection per API 653	Monthly [API 653]
5.	Overpressure protection – HVLs (including thermal reliefs)	2x/calendar year not to exceed 7 ½ months
6.	Overpressure protection – non-HVLs (including thermal reliefs)	1x/calendar year not to exceed 15 months
7.	Breakout tank visual inspection	1x/calendar year not to exceed 15 months
8.	External visual inspection per API #653, using API certified inspector	1x/5 years or at quarter of corrosion rate life of the shell, whichever is less.
9.	External ultrasonic thickness measurement of the shell.	Based on corrosion. If unknown maximum interval is 5 years. Not to exceed 20 years
10.	Breakout tank integrity inspection for tanks built to API #2510	1x/5 years or based on corrosion not to exceed 20 years

Refer to Procedure 7.02 for inspection procedures on breakout tank relief systems.

5.5 Each in-service breakout tank shall be visually inspected, which could include the shell, wind girders, roof, stairs, ladders, piping, valves, nozzles, chimering, foundation or footings, tank gauges, and cathodic protection (if any).

5.6 Each in-service breakout tank shall be inspected for physical integrity of in-service atmospheric and low pressure steel aboveground breakout tank according to section #4 of API Standard #653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a company plan developed under 195.403(c)(3).

5.7 Each in-service breakout tank built to API #2510 standards shall be inspected for physical integrity according to section #6 of API Standard #510.

5.8 Provide adequate fire protection per paragraph 4.4.3 above. At a minimum, adequate fire protection means at least enough fire extinguishers with the ability to fight an incipient fire. The company shall follow NFPA 10 guidelines for minimum requirements for fire extinguishers.

The firefighting equipment shall checked for proper operation as required by the manufacturer and OSHA requirements. For portable fire extinguishers the following inspections would be required.

- Monthly visual inspections
- Annual inspection of all working parts
- Pressure test of the vessel once every 5 years

The firefighting equipment shall be plainly marked so that its identity as firefighting equipment is clear, and located so that it is easily accessible during a fire.

5.9 Correct any condition that could result in unsafe operation of the system prior to the next inspection.

5.10 The manual inspection of over pressure protection shown in the section 5.4 table above shall include the following in the inspection documentation.

- Set point
- Span
- Zero of the control device
- As found and as left

5.10 Electronic testing of pressure control and level control shall include the following:

- Applicable electronic control devices such as transducers and station logic controller
- Communications linkage between components

5.11 Conduct capacity reviews of the over pressure protection devices by following O&M procedure #7.02 and the requirements listed below.

- Review and employ manufacturer data to derive factors affecting the calculation of capacity and/or direct measurement during full flow conditions
- When capacity is inadequate, the company shall develop an action plan and schedule for repair or replacement of the over pressure protection device

Note: All above indicated specifications, recommended practices, or standards, if referenced in 49CFR 195, are to be the currently referenced edition, otherwise it is to be the current edition.

6. RELATED PROCEDURES

6.01 Atmospheric Corrosion
6.02 Internal Corrosion
7.02 Pressure Regulators and Relief Devices
9.01 Repair Procedures

7. RECORDS

7.1 The “Breakout Tank Inspection and Testing”, Form 4.02A or equivalent may be used to document monthly tank inspections.

7.2 The “Relief Valve Report”, Form 7.02A or equivalent may be used for documentation. See Procedure 7.02 for vessel relief valves.

7.3 These records are to be retained for at least five years.

PUMPING EQUIPMENT
Hazardous Liquid Pipeline O&M Procedure #4.03

Primary Ref: 49 CFR 195.434	Updated: Jan 2016

1. REFERENCE

49 CFR, Section 195.262, 195.434, 195.436, 195.438, and NFPA 10 (Standard for Portable Fire Extinguishers).

2. PURPOSE

The purpose of this procedure is to define proper operation and maintenance of pumping equipment and related facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (140) _______________ is responsible for the proper operation and maintenance of pumping equipment.

The (141) _______________ is responsible for the scheduling, conducting, and record keeping of the requirements of this procedure.

4. GENERAL

4.1 Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn the presence of hazardous vapors in the pumping station building.

4.2 The following must be provided in each pump station.

4.2.1 Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.

4.2.2 A device for the emergency shutdown of each pumping station.

4.2.3 If power is necessary to actuate the safety devices, an auxiliary power supply.

4.2.4 Adequate firefighting equipment. Use NFPA 10 (Standard for Portable Fire Extinguishers) as a guide.

4.2.5 Signs visible to the public with contact information and information warning the public of the hazards. The signs shall contain the name of the company and a telephone number, including area code, where the company can be reached at all times.

The signage shall include prohibiting smoking or open flames where there is possibility of the presence of hazardous liquids or flammable vapors.

4.2.6 Each pumping equipment and/or pump station must be protected from vandalism and unauthorized entry. The company shall use one or more of the following security techniques at pump stations, breakout tanks, and other exposed facilities.

- Security fencing
- Locks on equipment
- Other options may be used if reviewed and documented and described in the PSOM

Vandalism history shall be evaluated during the continuing surveillance reviews and may dictate which security method is prudent. The protection from vandalism provided at pumping station inspected should be adequate to prevent the level of vandalism experienced at the site.

Pump stations that may be exposed to outside force damage such as vehicular damage should have some type of protection surrounding them. Typically this would be bollards.

4.3 Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

4.4 Except for offshore pipelines pumping equipment may not be installed:

4.4.1 On any property that shall not be under the control of the operator; or

4.4.2 Less than 50 feet (15 meters) from the boundary of the station.

4.5 Provide adequate fire protection per paragraph 4.2.4 above. At a minimum, adequate fire protection means at least enough fire extinguishers with the ability to fight an incipient fire. The company shall follow NFPA 10 guidelines for minimum requirements for fire extinguishers.

The firefighting equipment shall checked for proper operation as required by the manufacturer and OSHA requirements. For portable fire extinguishers the following inspections would be required.

- Monthly visual inspections
- Annual inspection of all working parts
- Pressure test of the vessel once every 5 years

The firefighting equipment shall be plainly marked so that its identity as firefighting equipment is clear, and located so that it is easily accessible during a fire.

4.6 Each pump station or other exposed facility must be protected from vandalism and unauthorized entry.

4.7 Smoking and open flames are prohibited in each pump station or other exposed facility.

5. PROCEDURE

5.1 Ensure that each pump station building has adequate ventilation. Install hazardous vapor warning devices where non-existent or where existing warning device no longer functions.

5.2 Ensure that each pump station is equipped per paragraph 4.2 above.

5.3 Test each safety device under conditions approximating actual operating conditions to verify that the device is properly functioning.

5.4 Provide adequate fire protection per paragraph 4.5 above. The firefighting equipment shall checked for proper operation, plainly marked so that its identity as firefighting equipment is clear, and located so that it is easily accessible during a fire.

5.5 Record daily operating data including as a minimum, pump station discharge pressure.

5.6 Correct any condition that could result in an unsafe operation of the system prior to the next inspection.

6. RELATED PROCEDURES

7.02	Pressure Regulators and Relief Devices
14.03	Prevention of Accidental Ignition
14.05	Firefighting Equipment

7. RECORDS

7.1 Maintain daily operating records that indicate, at a minimum, pump station discharge pressure.

7.2 These records are to be retained for at least three years.

CONTINUING SURVEILLANCE
Hazardous Liquid Pipeline O&M Procedure #5.01

Primary Ref: 49 CFR 195.401	Updated: Jan 2016

1. REFERENCE

49 CFR, Section 195.401.

2. PURPOSE

The purpose of this procedure is to describe and summarize the various continuing surveillance programs within this O&M Manual and conduct an annual review of O&M documentation. The programs, or procedures, are used for evaluating pipeline systems, segments, and related facilities and, if necessary, taking appropriate action to resolve a problem.

3. RESPONSIBILITY FOR IMPLEMENTATION

The ___________ (77) is responsible for inspections and maintenance, including the completion of any required forms or reports.

The ___________ (77) is responsible for evaluation of the pipeline condition and recommendations affecting the status of the pipeline. This would include remedial action and possible shutdown of the pipeline.

4. GENERAL

4.1 Although covered and expanded extensively within individual procedures in this O&M Manual, the various surveillance programs are summarized in Section 5. "PROCEDURE", for reference.

4.2 Surveillance procedures and instructions are to be reviewed with employee(s) and/or contract personnel at the time of a specific inspection, and on an intermittent basis such as safety, tailgate, and operations meetings.

Training and/or qualification of personnel is necessary to perform these functions.

4.3 Communication to employees and contract people about the importance and the purpose of continuing "on-site" inspections and related records, must be done on a periodic and routine basis, and stressed that the reason is to detect changing conditions that could eventually result in a hazard to the public and property.

4.4 Should adverse changes or anomalies to a pipeline system, segment, or related facilities be determined by surveillance or inspection, but no immediate hazard exists, a planned and scheduled remediation, phaseout, or shutdown program shall be initiated. However, if damage or adverse conditions are found that could create a dangerous or hazardous situation, an immediate shutdown or operating pressure and MOP reduction may be necessary until the problem is resolved.

5. PROCEDURE

5.1 The following is a list of the minimum required surveillance and inspection programs that shall be reviewed annually. For detailed guidance, consult the specific procedure. The procedure is indicated after each task. Each task is unique and is designed to identify abnormal or unusual operating and maintenance conditions.

5.1.1	Investigation of Failures and Accidents	1.03
5.1.2	Damage Prevention Program Includes: excavation activities, and horizontal directional drilling.	3.01
5.1.3	Pipeline Patrolling/Leak Survey Includes: pipeline R/W observation for leaks, construction activity, exposed pipe, erosion, and other detrimental effects on the pipeline.	5.03
5.1.4	Corrosion Control and Cathodic Protection Includes: atmospheric, internal and external corrosion, pipeline examination, CP maps and records.	Section 6 (all)
5.1.5	Emergency Valve Maintenance Includes: emergency and blowdown valve maintenance, valve security, valve corrosion.	7.01
5.1.6	Pressure Regulators and Relief Devices (Overpressure safety devices)	7.02
5.1.7	Pipeline Repair Procedures Includes: preliminary investigation, damage evaluation, and repair of any damage or defect.	9.01
5.1.8	Pressure Testing	15.01

5.2 Once per calendar year a review shall be conducted by the assest unit pipeline team. Normally this review shall be conducted in the first quarter of the year and would review the previous calendar year records. Use form #5.01A to conduct the review.

5.3 The following is a list of the company pipeline team. The pipeline team shall have appropriate training and/or qualification as necessary to perform their team functions.

- ______________, team leader
- ______________, engineering support
- ______________, pipeline maintenand and operations support
- ______________, compliance and regulatory support
- ______________, optional pipeline consultant

5.4 If after review and analysis by the pipeline team of any or all of the above procedures, a hazardous condition is detected or exists affecting persons or property in the area, immediate steps shall be taken to reduce or eliminate the hazard, including a complete shutdown of the system.

5.5 Management must be advised, if not already involved, of the situation, immediate steps taken, and proposed actions to resolve the condition.

5.6 If any part of a pipeline system, facility, or related component is determined to be damaged, defective, or in an unserviceable condition, and the degree of non-serviceability is established, the following options should be considered. Obviously if an immediate or potential <u>hazard to people and property</u> exists, the system should be shutdown and secured.

Options:
1) Recondition or phaseout
2) Replace
3) Abandon
4) Reduce MOP and operating pressure
5) Modify facilities and/or operating conditions

5.7 Should other adverse changes or anomalies to a pipeline system, segment, or related facilities be determined by surveillance or inspection, but no immediate hazard exists, a planned and scheduled remediation, phaseout, or shutdown program shall be initiated. However, if damage or adverse conditions are found that could create a dangerous or hazardous situation, an immediate shutdown or operating pressure and MAOP reduction may be necessary until the problem is resolved.

6 <u>RELATED PROCEDURES</u>

All procedures indicated in Paragraph 5. "<u>PROCEDURE</u>", above.

7 <u>RECORDS</u>

Use form #5.01A or equivalent to document the continuring surveillance review.

PROCEDURE 5.02

NOT CURRENTLY IN USE

PIPELINE PATROLLING
Hazardous Liquid Pipeline O&M Procedure #5.03

Primary Ref: 49 CFR 195.412, 195.404	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.412, 195.404, and ASME B.31.4, section #451.4 and #451.5.

2. PURPOSE

   To establish a patrol program to observe the surface conditions on and adjacent to the right of way of the pipeline system.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (154) _______________ is responsible for scheduling and conducting the pipeline patrolling program.

4. GENERAL

   4.1 The pipeline system shall be patrolled to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, construction activity, exposed pipe, erosion, and other factors that may affect the safety and operation of the pipelines.

   While patrolling, particular attention should be with: bridge and aerial crossings; unstable soil areas like landslide, river banks and exposed water crossings; areas susceptible to washouts; railroad crossings; and attachments to buildings or structures and/or any other support structure.

   4.2 The patrol methods may include walking, driving, flying or other means of traversing the right-of-way as appropriate.

   4.3 All field personnel shall be responsible to observe, investigate and report any activity noted during the performance of their normal duties and other pipeline inspection activities that could adversely affect the safety, operation and maintenance of the pipeline facilities.

   4.4 ROWs shall be kept clear of excessive debris, trees, brush, and canopy so there shall be clear visibility and reasonable access for maintenance crews. This includes maintaining access to emergency valve locations.

   4.5 Diversion ditches or dikes shall be maintained where needed to protect against wash outs of the line and erosion of the landowners property.

4.6 Underwater crossings shall be inspected for sufficiency of cover, accumulation of debris, or any other condition affecting the safety and security of the crossing. Inspections should also be conducted as the crossing may be affected by floods, storms, or mechanic damage.

5. FREQUENCY

5.1 Patrol pipeline right-of-way and areas adjacent to the right-of-way at least 26 times per year, at intervals not to exceed 3 weeks.

5.2 Inspect each crossing under a Coast Guard defined navigable waterway to determine the condition of the crossing at intervals not exceeding 5 years. This does not include offshore pipelines.

5.3 An increase in frequency of patrols may be warranted by the size of line, operating pressure, terrain, weather, construction activity, erosion/slippage, highway, bridge, railroad crossing and leak history and at the discretion of the pipeline facility management.

5.4 Supplemental patrols shall also be considered when the company has Special Permits requirements, alternative MAOP segments, and/or preventive and mitigative measures associated with the company Integrity Management program requirements.

6. PROCEDURE

6.1 Establish a scheduling plan in each operating location area for patrolling pipelines. Include inactive lines in the plan (except lines that are abandoned). For pipeline maintenance scheduling, the company shall use the "Compliance Assurance System" (CAS) or equivalent tracking system. The CAS system is located online at the following website: www.complianceservicesinc.net.

6.2 Update the patrol maintenance scheduling as necessary.

6.3 All aerial patrol reports and other reports of activities or construction in the vicinity of pipeline facilities shall be field investigated.

6.4 Aerial patrol reports or other reports received that indicate that the safety, operation or maintenance of the pipeline facilities could be in imminent danger, shall be immediately relayed and investigated by the responsible supervisor.

7. TRAINING

7.1 Training of both company and contractor personnel related to patrolling shall be handled by the company operator qualification (OQ) plan.

8. RELATED PROCEDURES

5.01 Continuing Surveillance

9. RECORDS

9.1 Record each item found during a patrol that requires further investigation to provide a permanent record on Forms 5.03A and 5.03C or equivalent forms. This record shall ultimately indicate the actual situation and its disposition.

9.2 Maintain pipeline patrolling records for a minimum of 2 years, or until the next inspection is made, whichever is longer.

PIPELINE MARKERS AND SIGNS
Hazardous Liquid Pipeline O&M Procedure #5.04

Primary Ref: 49 CFR 195.410, 195.434	Updated: Jan 2016

1. REFERENCE

49 CFR, Section 195.410, 195.434, API #1109 Marking Liquid Petroleum Facilities, and Common Ground Alliance Best Practices (practices #2-5, #4-20).

2. PURPOSE

The purpose of this procedure is to establish a marking system for pipelines and other facilities operated by the Company.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (160) _______________ is responsible for installation and maintaining the pipeline markers and signs on all pipeline facilities.

4. GENERAL

4.1 49 CFR Section 195.410 requires installation and maintenance of pipeline markers in sufficient number so that the pipeline's location is accurately known. This includes line markers at each crossing of a public road and railroad and where necessary to identify the location of a pipeline to reduce the possibility of damage or interference (except as provided in 4.3 below). This also includes all aboveground locations in areas accessible to the public.

4.2 Although it is not the intent to identify the precise location of pipelines by marker placement, they should be installed over the pipeline or at a minimal offset.

4.3 Line markers are not required for buried pipelines located:

4.3.1 Offshore or at crossings of or under waterways and other bodies of water; or

4.3.2 In heavily developed urban areas such as downtown business centers where:

4.3.2.1 The placement of markers is impracticable and would not serve the purpose for which markers are intended; and

4.3.2.2 The local government maintains current substructure records.

4.4 All pipeline marker signs must include the word “Warning,” “Caution,” or “Danger” followed by the words “Petroleum (or the name of the hazardous liquid transported) Pipeline” written on a background of sharply contrasting color, all of which must be in letters at least one inch (25mm) high with one-quarter inch (6.4mm) stroke.

4.5 The name of the operator and the telephone number (including area code) where the operator can be reached at all times must be included on all pipeline markers and signs.

4.6 All pump station and breakout tank area signs shall include, at a minimum, the name of the operator, and a 24-hr emergency telephone number. Pipeline markers meeting the requirements of §195.410 (line markers), may be used to satisfy this requirement, provided they are located within/on the facility fence or immediately adjacent to the fence.

4.7 Signs must be maintained on all sides that are visible to the public around each pumping station and breakout tank area.

4.8 Signs need not be installed for office type facilities such as those located in office parks, multistory, or high-rise buildings.

5. PROCEDURE

5.1 Line Markers for Buried Pipelines

5.1.1 Place a sign at existing fence lines in locations where markers are required.

5.1.2 Place a sign at visually identifiable property lines, which are not fenced, in locations where markers are required unless the sign shall interfere with land usage.

5.1.3 For pipelines that are within and paralleling public right of way, place signs on the public area right-of-way line where the pipeline enters and exits the right-of-way area with the front of the sign facing towards the right-of-way, at spacing determined appropriate for the expected frequency of excavation activity. Where possible, signs should be at changes of direction and be visible sign-to-sign.

5.1.4 Install aerial patrol signs on pipelines that are flown on a routine basis where a need exists to have reference markers. Space these signs at about 5 mile (8 km) intervals, unless local conditions indicate closer or farther spacing would be better.

5.1.5 Install markers at all locations necessary to identify the location of the pipeline to reduce the possibility of damage or interference.

5.2 Line Markers for Public Road and Railroad Crossings

5.2.1 Place one sign on each side of the crossing at the right of way of all public roads and railroad crossings.

5.2.2 Place one sign on the downstream side of the crossing at the right of way line of non-public roads.

5.2.3 Whenever one sign is required (non-public roads only), it must be capable of being easily seen and identifiable when standing on the opposite right of way line during all times of the year. If not, install two signs, one on each side of the crossing at the right of way line.

5.3 Aboveground Pipelines

Install and maintain signs at aboveground pipeline facilities in areas that are accessible to the public.

5.4 Pipeline Marker Sign Mounting

5.4.1 Paint fence posts on both sides of the road or railroad where the pipeline crosses, unless landowner has made a specific request not to paint these posts.

5.4.2 Mount signs on fence where pipeline crosses.

5.4.3 Place signs parallel to road, highway, railroad and other crossings to obtain the greatest visual attention.

5.4.4 Consider vertical type pipeline marker signs for use in:

5.4.4.1 Populated locations.

5.4.4.2 Those areas where conventional pipeline marker signs may be subject to vandalism, vehicular impact, or damage from livestock.

5.4.4.3 At locations where these markers may be less objectionable to landowners.

5.4.5 In the areas covered by 5.4.4.2 above, mount decal-type signs on PVC or steel pipe posts, or flexible plastic composite posts.

5.5 Pump Stations and Breakout Tank Areas

5.5.1 Install and maintain signs visible to the public around each pumping station and breakout tank area.

5.5.2 Ensure that each sign contains, at a minimum, the name of the operator and a 24-hr emergency telephone number. The 24-hr emergency phone number must include the area code.

5.6 Monitoring

5.6.1 Existing markers shall be observed by employees as follows:

5.6.1.1 During normal travels required by pipeline operation and maintenance.

5.6.1.2 During scheduled patrols of the pipeline.

5.6.1.3 During the annual cathodic protection survey.

5.6.2 Replace/repair missing, damaged, outdated, or deteriorated signs within a reasonable time interval.

6. RELATED PROCEDURES

5.03 Pipeline Patrolling
4.02 Breakout Tanks
4.03 Pumping Equipment

7. RECORDS

7.1 Signed documentation records are to be retained for at least five years. Form 5.03A, or an equivalent may be used for sign documentation.

ATMOSPHERIC CORROSION
Hazardous Liquid Pipeline O&M Procedure #6.01

Primary Ref: 49 CFR 195.581-195.589	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.581, 195.583, 195.587 & 195.589.

2. PURPOSE

   The purpose of this procedure is to establish the requirements for inspection and maintenance of aboveground pipeline systems for atmospheric corrosion.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (167) __________________ is responsible for scheduling, conducting inspections, and record-keeping of atmospheric corrosion inspections as required by this procedure. The (168) __________________ shall initiate any corrective/maintenance actions required as a result of these inspections.

4. GENERAL

   4.1 A pipeline system includes all pipeline facilities used in the transportation of hazardous liquids, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, fabricated assemblies, and metering stations.

   4.2 The pipeline and pipeline facilities shall be cleaned coated for each portion of the pipeline that is exposed to the atmosphere. Exceptions are noted below but DO NOT include offshore splash zones and soil-to-air interfaces:

   You need not protect against atmospheric corrosion if the company can demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion shall;

   - Only be a light oxide, or
   - Not affect the safe operation of the pipeline before the next scheduled inspection

   4.3 Coating material must be suitable for the prevention of atmospheric corrosion. Paint or coating materials used shall be non-conductive that shall isolate the metal from the atmosphere. In order to prevent atmospheric corrosion, the coating material's physical, chemical and electrical characteristics must be evaluated before its application by the company corrosion engineer or company designated corrosion program leader.

4.4 Pipeline systems or portions thereof, subject to atmospheric corrosion or moisture penetration and retention, shall be inspected to assure detection of corrosion before detrimental damage, Category 3 Corrosion (heavy, obvious pitting in excess of 10% of new nominal wall thickness) is sustained. (NOTE: See Form 6.01A for explanation of category and conditions).

4.5 The facilities' operating history, future anticipated operating conditions, evidence of possible corrosion found during routine observations, and actual inspection results shall be considered when establishing inspection frequencies.

4.6 Inspection programs for atmospheric corrosion shall include, but not be limited to, areas such as under hold-down straps, between pipe and pipe supports, platform risers and riser clamps, at pipe penetrations of building walls, and thermally insulated meter piping.

4.7 Periodically, at least once every 3 calendar years (not to exceed 39 months) between onshore inspections and each calendar year (not to exceed 15 months) for offshore inspections, check the condition of wear pads, supports or sleeves, and riser splash zones on a sample basis to confirm continued protection of the pipe, especially in areas conducive to corrosion. Such areas would typically be those where moisture is present on the pipe due to reasons other than normal precipitation. The results of inspections, geographic location, and pipe environment shall be used to determine an appropriate continuing inspection level.

4.8 Corrosion, leaks, and defects may be safety related conditions. Refer to the Reporting of Safety Related Conditions procedure (1.02) for identification and reporting of such conditions.

5. PROCEDURE

5.1 Inspect all bare aboveground piping at intervals not exceeding three (3) years, not to exceed 39 months for onshore pipelines and at least once each calendar year, but not to exceed fifteen (15) months for offshore pipelines.

5.2 The primary method of inspection is visual. Further non-destructive testing (NDT) techniques (such as ultrasonic thickness measurements, pit depth gauge readings, radiography, etc.) may be implemented if visual evidence of corrosion damage or other conditions warrant. (See Section 5.8)

5.3 As a minimum, personnel conducting atmospheric corrosion inspection shall look at the following areas;

- pipe at soil-to-air interfaces
- under thermal insulation
- under disbonded coatings
- at pipe supports (pipe resting on pipe supports and through-wall piping in buildings)
- in splash zones
- at deck penetrations
- in spans over water

5.4 Maintain a continuing program of painting based upon results of the external inspection program.

5.5 Inspect the transition zone of pipe entering the ground (or water for offshore pipelines) to confirm it is properly coated whereby penetration of moisture between the pipe and coating is prevented. Whenever a condition is observed where moisture may be retained between the coating and pipe, remove the coating, inspect the pipe, evaluate severity of corrosion if present, take remedial actions if necessary, and recoat the pipe prior to the next inspection.

5.6 For thermally insulated systems, visual inspection of the external jacket to ensure its integrity against moisture intrusion under the jacket is usually sufficient; if the integrity of the external jacket has been breached and liquid water may be present against the carrier pipe surface, additional inspection techniques may be required to detect possible corrosion.

5.7 Areas where liquid water may accumulate or be trapped against the outside of the pipeline (including, but not limited to, under pipe hold-down straps or at pipe supports) may require special attention. Caulks, mastics or other sealants should be used to prevent water accumulation at these sites.

5.8 Repairs and preventive maintenance actions necessitated by these inspections shall be completed prior to the next inspection.

5.9 In cases where general or localized corrosion causes pipe wall loss to exceed 10% of the nominal new pipe wall thickness, District Engineer or designee shall review the pipeline MOP for possible pipeline repair requirements. The District Engineer or designee shall develop a specific plan on how to clean, repair, and coat the pipeline for each loss meeting this 10% criterion.

The company shall use one or more of the following as guidance in for determining the remaining strength of a pipeline. Equivalent standards approved by the district engineer or designee may also be used.

1) Modified ASME/ANSI B31G (49CFR195 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (49CFR195 currently referenced edition).

The company shall use one or more of the following as guidance in cleaning and prepping pipe surfaces. Equivalent standards approved by the district engineer or designee may also be used.

1) NACE #1 – SSPC – SP5, White Metal Blast Cleaning, Joint Surface Preparation Standard
2) NACE #2 – SSPC – SP10, Near White Metal Blast Cleaning, Joint Surface Preparation Standard
3) NACE WJ-1, Waterjet Cleaning of Metals, Joint Surface Preparation Standard
4) NACE SSPC-TR-4, Preparation of Protective Coating Specifications for Atmospheric Corrosion

The company shall use one or more of the following as guidance in applying pipe coating. Equivalent standards approved by the district engineer or designee may also be used.

1) NACE RP 0106-2006, Liquid Epoxy Coatings for External Repair, Rehabilitation, and Weld Joints on Buried Steel Pipelines
2) NACE RP 0402-2002, Field Applied Fusion Bonded Epoxy (FBE) Coating Systems for Girth Weld Joints: Application, Performance, and Quality Control

6. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
9.01 Repair Procedures

7. RECORDS

7.1 Complete Form 6.01A or equivalent to document the extent of external corrosion on aboveground facilities.

7.2 Complete the Pipeline Maintenance and Surveillance Form (Form 3.01B) whenever external corrosion is identified and a repair or a preventive maintenance action, other than painting, is required.

7.3 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

INTERNAL CORROSION
Hazardous Liquid Pipeline O&M Procedure #6.02

Primary Ref: 49 CFR 195.401, 195.579	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.401(b), 195.579, NACE SP0208-2008: sections #3.2.2.1 (Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines), and NACE RP 0775-99, Table #2 (Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations)

2. PURPOSE

To establish the requirements for the detection, monitoring, and control of internal corrosion, and required corrective actions for pipeline facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (173) ______________ is responsible for scheduling, conducting, and record keeping of internal corrosion inspection as required by this procedure.

The (174) ______________ shall be responsible for repairing internal corrosion damage and mitigating the detrimental effects of internal corrosion.

4. GENERAL

4.1 This procedure is required if corrosive liquids are ever allowed to flow through or remain in the pipeline.

4.2 A pipeline system includes all pipeline facilities used in the transportation of hazardous liquids, including, but not limited to, gathering lines, line pipe, valves and other appurtenances connected to line pipe, fabricated assemblies, and metering stations.

4.3 Corrosive hazardous liquids shall not be transported unless the corrosive effect of the liquid has been investigated and measures have been taken to eliminate or minimize internal corrosion.

4.4 Potentially corrosive hazardous liquids shall not be transported without monitoring equipment that shall detect the presence of internal corrosion. Where corrosive liquid is being transported, coupons or other suitable means shall be used to determine the effectiveness of the steps taken to minimize internal corrosion.

4.5 If corrosion inhibitors are used to mitigate internal corrosion, coupons must be used to determine their effectiveness.

4.6 If repair, replacement, or operating pressure reduction is necessary, review Reporting of Safety Related Conditions procedure (Procedure 1.02) to see if a reportable safety related condition exists.

5. PROCEDURES

5.1 Internal Inspections

5.1.1 Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion. If internal corrosion is noted visually, further investigation including NDT techniques, shall be used to quantify the extent of the corrosion.

5.1.2 Vessels, including breakout tanks, and other fabrications shall be visually internally inspected when the opportunity to do so exists in conjunction with other maintenance activities or at intervals dictated by code requirements.

5.1.3 When internal corrosion or metal loss is observed in piping not previously monitored, remedial action and monitoring shall be initiated prior to the next inspection.

5.1.4 A sample of any foreign material recovered from inside the pipeline system shall be submitted for analysis and any necessary remedial action indicated by the analysis must be taken prior to the next inspection.

5.1.5 Electromagnetic flux leakage, ultrasonic, or other types of "smart" pigs should be run in a pipeline to supplement other inspection techniques.

5.2 Hydrocarbon Liquid Analysis and Evaluation

5.2.1 If there is a reasonable possibility that potentially corrosive hydrocarbon liquid could occur in a pipeline system, samples shall be taken at applicable locations and tested for the presence and concentration of corrosive components. Testing shall be done once per calendar year or when new products are introduced into the system.

5.2.1. A – Samples should be tested for:

- Presence of free liquid water
- Basic Sediment and Water (BS&W)
- Presence of Hydrogen Sulfide (H_2S), Carbon Dioxide (CO_2) and Oxygen (O_2)
- pH
- Sulfate-reducing or Acid–producing microbiological colonies

Samples should be obtained following ASTM D 4057 (Practice for Manual Sampling of Petroleum and Petroleum Products) and provided to the testing laboratory within 96 hours of the sample being taken.

5.2.2 Where potentially corrosive hydrocarbon liquid is found as a result of liquid testing, the quantity of impurities should be evaluated per NACE SP0106, Appendix B. Once the quantity of impurities has been identified, the impact of the impurity should be reviewed per NACE SP0106, Appendix C. If it is determined that the impurity could be corrosive then initiate the remedial action prior to the next test.

5.2.3 Installation of Monitoring Devices

5.2.3.1 Identify checkpoint locations at places most susceptible to internal corrosion such as low elevation points, dead ends and drips.

5.2.3.2 Select and install monitoring devices such as weight loss coupons or electrical probes, either resistance or polarization, giving consideration to size of pipe, type of system, operating conditions, simplicity of installation and ease of gathering information. Install liquid sampling facilities if applicable.

5.2.3.3 Prepare and maintain a schematic diagram showing physical and operating characteristics of the pipeline system, the location of check points and the type of monitoring devices used.

5.2.4 Monitoring and Detection

Monitor checkpoints and record the results at least twice each calendar year with intervals not exceeding 7½ months. Monitor more frequently if the level of the corrosive component increases or the effectiveness of the anti-corrosion measures needs to be confirmed.

When coupons are used, the company shall develop specific procedures for removal of the coupons for each type of coupon used. NACE Standard RP0775-99 (Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations) shall be used as guide in development of these specific coupon removal procedures.

5.2.5 Remedial Action

5.2.5.1 Make a study of the pipeline systems to determine the scope of the possible internal corrosion if it is determined by inspection or analysis that internal corrosion is occurring, or has occurred. The MOP shall be reviewed by the District Engineer. Refer to Procedure 8.01.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR 195 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, (49CFR 195 currently referenced edition) "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe".

5.2.5.2 Apply at least one of the following mitigation measures prior to the next inspection if inspection reveals internal corrosion to be occurring, or if previously installed monitoring equipment shows corrosion to be occurring:

5.2.5.2.1 Eliminate free water in the pipeline by implementing an adequate pigging program, or by other appropriate methods.

5.2.5.2.2 Remove corrosive components.

5.2.5.2.3 Inject corrosion inhibitors.

5.2.6 Corrosion Rates from NACE RP 0775-99, Table #2.

	Average Corrosion Rate		**Maximum Pitting Rate**	
	Millimeters per Yr	**Mils per Year**	**Millimeters per Yr**	**Mils per Year**
Low	<0.025	<1.0	<0.13	<5.0
Moderate	0.025-0.12	1.0-4.9	0.13-0.20	5.0-7.9
High	0.13-0.25	5.0-10	0.21-0.38	8.0-15
Severe	>0.25	>10	>0.38	>15

6. <u>REPAIR</u>

If internal corrosion has or may have reduced the wall thickness of a segment of pipe to less than that required for the maximum operating pressure (MOP) pipe repair or replacement should be planned or the working pressure reduced, prior to the next inspection.

7. <u>RELATED PROCEDURES</u>

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
9.01 Repair Procedures

8. RECORDS

8.1. The "Pipeline Maintenance and Surveillance Form" (Form 3.01B) or an equivalent can be used to document whenever the pipeline is checked internally, repaired, or replaced.

8.2 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

EXTERNAL PROTECTIVE COATING
Hazardous Liquid Pipeline O&M Procedure #6.03

Primary Ref: 49 CFR 195.561, 195.559, 195.557	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.561, 195.559, 195.557, and NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems"

2. PURPOSE

To outline the practice for the installation of external protective coating for all buried, in the contact with the ground, or submerged hazardous liquid pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (180) ______________ is responsible to implement the requirements of this procedure.

4. GENERAL

4.1 Except bottoms of aboveground breakout tanks, each buried, in contact with the ground, and submerged pipelines require an external coating if.

4.1.1 Constructed, relocated, replaced or otherwise changed after
3/31/70 – interstate pipelines excluding low stress
7/31/71 – interstate offshore gathering excluding low stress
10/20/85 – intrastate pipeline excluding low stress
8/10/94 – low stress pipelines
7/11/91 – transports carbon dioxide
This does not include movement of pipe (195.424)

4.1.2 Converted under 195.5 and

4.1.2.1 Has external coating that meets 195.559 before pipeline is placed in service.

4.1.2.2 Is a segment that is replaced, relocated or substantially altered.

4.2 When choosing the material to use for repairing a coating, the Corrosion Engineer or equivalent shall determine if the coating material or coated pipe purchased meets the site specific conditions for the pipeline and environment. Specific conditions the corrosion engineer shall review include:

- Sufficiently ductile
- Proper adhesion characteristics
- Designed to withstand expected handling and installation conditions
- Designed to withstand environmental conditions, and
- Compatible with cathodic protection used on the pipeline.

4.3 In all cases of coating repair, whether during construction or after the pipeline is in service, the pipeline surface to be coated should be cleaned as well as possible of all dirt, grease, weld splatter or other foreign material. Instructions for the coating application prepared by the manufacturer should be followed.

5. <u>COATING PROCEDURE</u>

5.1 The purpose of external protective coatings is to isolate the pipeline from its environment and provide primary corrosion protection. Additionally, external protective coatings facilitate the application of cathodic protection.

5.2 The external protective coating applied for corrosion control must have the following characteristics and properties.

5.2.1 The coating must be applied on a properly prepared surface as recommended by the coating system manufacturer and be designed to mitigate corrosion of the buried or submerged pipeline.

5.2.2 The coating must have sufficient adhesion to the metal surface to effectively resist under-film migration of moisture.

5.2.3 The coating must be sufficiently ductile to resist cracking.

5.2.4 The coating must have sufficient strength to resist damage due to the handling and in-service soil stress.

5.2.5 The coating must have properties compatible with the application of cathodic protection to the pipeline.

5.2.6 The coating must have low moisture absorption and high electrical resistance.

5.2.7 Each external protective coating must be inspected by electrical test methods ("jeeping") just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

The jeeping inspector shall consider NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems", and manufacturer's specifications (coating & instrument) to determine applicable settings for the jeep being utilized. If voltage settings are too high, it may damage the coating or conversely if the voltage setting of the jeep is too low it may not identify all coating holidays.

5.2.8 Each external protective coating must be protected from damage which could result from adverse ditch conditions or from supporting blocks.

5.2.9 If coated pipe is installed by horizontal directional drilling, boring, driving, or other similar method, precaution must be taken to minimize damage to the external coating during installation.

5.3 Coated pipe sections connected by welding and/or mechanical coupling including valves or other underground or submerged appurtenances shall be considered field joints. External coating of field joints must be equal to or better than the coating of the pipeline.

5.4 Existing Coated Pipelines

5.4.1 Apply an external protective coating to:

5.4.1.1 Poorly coated or bare portions of pipeline segments that have been exposed for repair or inspection.

5.4.1.2 Pipeline segments that replace existing pipe.

5.4.2 Inspect and repair all coating on replacement segments and coating repairs for defects caused by installation activity.

5.4.3 Existing coating may require repair or upgrading in areas where criteria for achieving cathodic protection are not being met or if any coating damage is discovered

5.5 New Pipelines

5.5.1 Apply an external protective coating to all new buried pipelines.

5.5.2 Inspect all coating on new pipeline segments and repair defects caused by installation.

5.6 Surface Preparation

5.6.1 In removing coating to make tie-ins, care must be taken to avoid disbonding of the adjacent coating. Edges of thick film coating must be tapered and enough of the wrapper removed to ensure adhesion of the new coating to the existing coating.

5.6.2 The surface to be coated must be thoroughly cleaned with solvents to remove oil and grease. All dust, dirt, rust, mill scale, loose shop coating, dead primer, welding slag, and burrs must be removed with wire brushes or scrapers.

5.7 Repair of Coating Defects

5.7.1 Inspection shall follow all coating applications and just prior to lowering the pipe into the ditch or submerging the pipe. Any defects shall be repaired.

5.7.2 A sufficient portion of the coating must be carefully removed from defective areas of pipe to ensure that the remaining coating is satisfactory and well bonded. Edges of the area should be tapered to increase the strength of the patch.

5.7.3 Foreign matter must be removed from the area to be repaired.

5.7.4 Primer applied to the area. Follow manufacturer's recommendations.

5.7.5 The coating material used for patching must be such that proper adhesion shall occur between the existing coating material and the patching material.

5.8 Surveys for Discovering Coating Defects and CP Levels

5.8.1 If coating damage is discovered in many exposed pipe locations due to age, poor construction installation, environmental damage, or other, the company shall consider conducting a “close interval survey” (CIS) to determine if there are areas of in-adequate CP protection.

5.8.2 If coating damage is discovered in many exposed pipe locations due to age, poor construction installation, environmental damage, or other, the company shall consider conducting a “direct current voltage gradient” (DCVG) survey to determine if there are other areas of potentially damaged coating.

5.8.3 Any locations that have both low CIS levels below -850mV criteria and potential indications of coating damage from the DCVG report shall be considered high priority. These locations shall be prioritized in the O&M remedial actions and excavated to determine actual conditions and look for external corrosion.

6. <u>RELATED PROCEDURES</u>

5.01 Continuing Surveillance
6.04 Internal and External Examination of Buried Pipelines
6.05 Cathodic Protection/External Corrosion Control
6.06 Electrical Isolation
6.08 Cathodic Protection Records

7. <u>RECORDS</u>

7.1 Submit appropriate as-built information to the District Office for updating the drawings and records.

7.2 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

INTERNAL & EXTERNAL EXAMINATION OF BURIED PIPE
Hazardous Liquid Pipeline O&M Procedure #6.04

Primary Ref: 49 CFR 195.401, 195.569, 195.579	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.401(b), 195.569, 195.571, and 195.579.

2. PURPOSE

   To establish a standard program of examination of buried pipelines for evidence of internal of external corrosion.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (186) _______________ is responsible to implement the requirements of this procedure and to document the test results whenever buried hazardous liquid piping is exposed for any reason.

4. GENERAL

   4.1 A continuing program of examination and recording of the results of the inspection of buried pipelines is mandatory for both internal and external corrosion.

   4.2 It is intended that examinations shall monitor pipelines for the effectiveness of both internal and external protective measures.

   4.3 Corrosion, leaks, and defects shall be evaluated to determine if they are safety-related conditions.

5. PROCEDURE

   5.1 Whenever buried piping is exposed for any reason, the exposed portion of the coating must be visually examined to determine external coating condition.

   5.2 If a line is bare or the coating is removed on a well coated line, inspect the pipe for external corrosion. If the coating is deteriorated examine the pipe under the deteriorated coating for evidence of external corrosion.

   5.3 If external corrosion is noted visually, further investigation including NDT techniques, shall be used to quantify the extent of the corrosion.

If external corrosion requiring remedial action is found, additional investigation circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

5.4 Visually inspect the full circumference of piping if one or more of the following conditions exist.

5.4.1 Continuing corrosion is observed.

5.4.2 CP tests, current requirements or surveys indicate corrosion may be occurring.

5.4.3 Previously unidentified coating deterioration is observed or suspected.

5.4.4 Corrosion is observed on the piping which is of a magnitude not previously documented or which may require repair. If repair is required, continue inspection longitudinally until pipe condition is satisfactory.

5.5 Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion. Then there must further investigation circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method (NDT), or both) to determine whether additional corrosion exists and the extent of the corrosion.

5.6 If visual examination indicates corrosion has occurred, initiate one or more of the following actions:

5.6.1 Calculate the acceptable minimum wall thickness limit after corrosion. If wall thickness is less than the calculated minimum, initiate a repair method as outlined in Repair Procedures (Procedure 9.01) or reduce the pipeline MOP (see 195.416(h) and Procedure 8.01).

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR 195 currently referenced edition), “Manual for Determining the Remaining Strength of Corroded pipelines.”

2) AGA Pipeline Research Committee, Project PR-3-805, (49CFR 195 currently referenced edition) "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe".

5.6.2 If repair is required, limit the operating pressure accordingly, until the repair is made.

5.6.3 Clean and apply coating and/or additional cathodic protection, as necessary, where active external corrosion is present or where coating is damaged or deteriorated. See procedure #6.03, External Protective Coating for details.

5.6.4 If internal corrosion is noted, apply or confirm compliance with the requirements of Internal Corrosion procedure (Procedure 6.02).

5.6.5 Determine if a safety related condition exists.

5.6.6 If the pipeline is conducive to stress corrosion cracking (SCC) formation, the company shall use third a party to conduct magnetic particle inspections to check for SCC.

5.6.7 If coating damage is discovered in many exposed pipe locations due to age, poor construction installation, environmental damage, or other, the company shall consider conducting a "close interval survey" (CIS) to determine if there are areas of in-adequate CP protection.

6. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
2.01 Record Keeping
5.01 Continuing Surveillance
6.02 Internal Corrosion
6.03 External Protective Coating
9.01 Repair Procedures

7. RECORDS

7.1 The "Maintenance and Surveillance Report" form (Form 3.01B) or an equivalent may be used to document this information.

7.2 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

Primary Ref: 49 CFR 195.563-195.588	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.563, 195.565, 195.567, 195.571, 195.573, 195.577, 195.585, 195.587, 195.588, and NACE RP #0169.

2. PURPOSE

To establish the minimum design requirements for pipeline protection systems to monitor and control external corrosion on buried, in contact with the ground, or submerged steel pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (192) _______________ is responsible for inspection, scheduling, and documentation as required by this procedure.

4. GENERAL

4.1 Pipelines as listed in procedure 6.03 Section 4.1 (a) must be provided with protection against external corrosion within one (1) year.

4.2 The amount of cathodic protection (CP) must be sufficient to mitigate corrosion which might result in structural damage, but must be controlled so as not to damage the protective coating or the pipe.

4.3 To determine whether cathodic protection required by 195 subpart H (corrosion control) the company shall do one of the following:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(2) Identify not more than 2 years after cathodic protection is installed, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP 0169 (incorporated by reference, *see* §195.3).

The following is a list of circumstances requiring a close interval survey:

- Initially, within 2 years of a newly constructed pipeline, relocated pipeline, or converted pipeline
- When there are indications of low CP, interference currents, or shorts that cannot be remedied
- When recommended by the company corrosion engineer or equivalent

4.4 General Corrective Action, Remedial Measures, and Timing of Repairs:

Any deficiencies identified in the corrosion control program must be corrected as required by 195.401(b), shown in the paragraph below. However, if the deficiency found involves a pipeline in the integrity management program under 195.452, the company shall correct the deficiency as required by 195.452(h).

Whenever the company discovers any condition that could adversely affect the safe operation of the pipeline, the company shall correct it within a reasonable time. However, if the condition is such a nature that is presents an immediate hazard to persons or property, the company may not operate the affected part of the system until the company has corrected the unsafe condition. [195.401(b)]

Timing of Remedial Measures

Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly or the pipeline must be shut down until the repair is made.

For general repairs (CP test stations, test leads) the repair shall be made before the next annual CP survey if determined by the corrosion engineer or designee that the test stations are critical to monitoring of the pipeline.

4.5 Cathodic protection test stations, commonly known as “electrolysis test stations” (ETS), or contact points shall normally be located and maintained at road crossings, pipeline mile markers, cased crossings, and other convenient locations. Recommended test station spacing should generally not exceed 1-mile.
Test leads found to be shorted and/or non-conductive during pipeline electrical potential surveys shall be repaired or replaced prior to the next required survey.

4.6 Test lead installation and maintenance shall be as follows:

1) The test leads shall be located at frequent enough intervals to obtain electrical measurements indicating the adequacy of cathodic protection. The company shall maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §195.571.
2) Provide enough looping or slack so backfilling shall not unduly stress or break the lead and lead shall otherwise remain mechanically secure and electrically conductive.
3) Prevent lead attachments from causing stress concentrations on pipe.
4) For leads installed on conduits, suitably insulate the lead from the conduit.
5) At the connection to the pipeline, coat each bare test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

4.7 Test Lead Installation: Provide enough looping or slack so backfilling shall not unduly stress or break the lead and the lead shall otherwise remain mechanically secure and electrically conductive. [195.567(b)(2)]

4.8 Pipelines receiving cathodic protection from a single CP source of current must be electrically continuous with itself and the source of current. Additionally, the structure to be protected must be electrically isolated from structures which are not intended to be protected.

4.9 Each impressed current type or galvanic anode CP system must be designed and installed so as to minimize any adverse effects on existing adjacent underground or submerged metallic structures.

4.10 Interference and/or stray currents effects from impressed current CP systems on foreign structures shall be minimized. Mitigation of interference effects may employ one or more of the following techniques: (1) installation of sacrificial anodes on the affected structure; (2) bonding the affected structure to the offending CP system; (3) coating the affected structure; (4) providing sacrificial anodes connected to each pipeline and buried immediately adjacent to each other in the same backfill. Mitigation measures other than the ones listed above may be utilized if approved by (193) ______________ .

4.11 All breakout tanks, buried pump station piping and bare pipelines must have cathodic protection provided.

Breakout tanks with cathodic protection to control corrosion must be operated and maintained according to API RP 651 (49 CFR 195 currently referenced edition).

Note: For the bottoms of aboveground breakout tanks with greater than 500 bbls (79.3 m^3) capacity built to API Specifications 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C, the installation of a cathodic protection system after October 2, 2000 must be in accordance with API RP651 unless the company can determine and provide reasons otherwise.

For the internal bottom of the above described breakout tank(s), the installation of a tank bottom lining after October 2, 2000, must be in accordance with API RP 652 unless the company can determine or provide reasons otherwise.

4.12 CP System for new pipelines must be installed not later than 1 year after construction.

4.13 CP System must be installed on existing pipelines that have an effective external coating. A pipeline does not have an effective external coating, and shall be considered bare; if it's cathodic protection current requirements are substantially the same as if it were bare. This does not apply to breakout tank areas and buried pumping station piping.

4.14 Submerged pipelines converted under 195.5 must have cathodic protection operational within 12 months of going into service.

4.15 All other buried or submerged pipelines that have an effective external coating must have cathodic protection.

5. PROCEDURE

5.1 Ensure that the CP system provides a level of protection that complies with one or more of the criteria listed in 5.2 below. More specifically, cathodic protection required by this procedure must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169 (incorporated by reference, see § 195.3). [195.571]

5.2 DOT acceptable criteria to assure adequate cathodic protection for steel pipelines are:

5.2.1 For onshore pipelines, a negative polarized (current applied) potential of at least -0.85 volt relative to a saturated copper-copper sulfate reference electrode. For offshore facilities, a negative polarized potential of at least 0.80 volt relative to a silver-silver chloride reference electrode. (Negative 0.85 volts vs. $Cu/CUSO_4$ is equal to -0.80 vs. Ag/AgCl). Voltage drops other than those across the structure to electrolyte boundary must be considered for valid interpretation of this voltage measurement. (See NACE RP 0169-2007).

5.2.2 A minimum of 100 mV of cathodic polarization. The formation of decay of polarization can be used to satisfy this criterion.

5.2.3 If the company has unprotected pipe the company shall reevaluate the unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows: [195.573(b)]

1) Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
2) The frequency of evaluation is at least once every 3 calendar years, but with intervals not exceeding 39 months.

Refer to O&M procedure #6.09 (Unprotected Pipe) for more details.

5.3 Special Conditions

5.3.1 For pipelines installed before October 19, 1988 which are bare or poorly coated externally, the measurement of a net protective current from the electrolyte to the pipe surface (as measured by the earth current technique) at predetermined discharge points may not be sufficient proof of adequate cathodic protection.

5.3.2 In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments and dissimilar metals, the criteria in Section 5.2 of this procedure may not be sufficient protection.

5.4 At pipeline locations where external corrosion-related leaks are discovered, a measurement of the pipe-to-soil cathodic potential shall be taken. If the level is less than that required by regulations, the (194) ______________ shall reevaluate the CP system capacity and upgrade it as necessary prior to the next inspection.

5.5 Perform tests and surveys of CP systems according to the frequency schedule listed in Table 6.05A.

5.6 Take prompt remedial action, at least prior to the next required survey, to correct conditions which cause the pipeline to fail to meet the applicable criterion.

5.7 If 4.8 above has not been satisfied, electrically inspect and/or install cathodic protection for breakout tank areas and buried pump station piping. These actions are to be taken within one calendar year.

5.8 Install cathodic protection systems on pipelines to which 4.10 above applies.

6. REMEDIAL MEASURES FOR CORRODED PIPE

If the company finds pipe with general corrosion that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, the company shall must replace the pipe. However, the company need not replace the pipe if;

(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

If the company finds that has localized corrosion pitting to a degree that leakage might result, the company shall replace or repair the pipe, unless the company reduces the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

7. METHODS USED TO DETERMINE THE STRENGTH OF CORRODED PIPE

Under §195.585, the company may use the procedure in ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines," or the procedure developed by AGA/Battelle, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)," to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

8. USE OF DIRECT ASSESSMENT TO EVALUATE EFFECTS OF EXTERNAL CORROSION

If the company uses direct assessment on an onshore pipeline to evaluate the effects of external corrosion, the company shall follow the requirements of section 195.588 for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

9. RELATED PROCEDURES

- 5.01 Continuing Surveillance
- 6.03 External Protective Coating
- 6.06 Electrical Isolation
- 6.07 Impressed Current Power Source Inspection

10. RECORDS

10.1. Record the location of cathodically protected pipeline, cathodic protection facilities, and neighboring structures bonded to cathodic protection system.

10.2 The pipe-to-soil surveys are to be recorded or plotted on the special forms or charts provided for that purpose.

10.3 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

TABLE 6.05A - REQUIRED TESTS FOR CATHODIC PROTECTION

SURVEY OR TEST	**FREQUENCY**
Pipe-to-Soil	Once each calendar year, but with intervals not exceeding 15 months.
Evaluation of un-protected pipe	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Critical Bond, Reverse Current Switches, Diodes	Six times each calendar year, but with intervals not exceeding 2½ months.
Non-critical Bonds	Once each calendar year, but with intervals not exceeding 15 months.
Electrical Insulation Test	Once each calendar year, but with intervals not exceeding 15 months, or when needed.
Rectifier Inspection	Six times each calendar year, but with intervals not exceeding 2½ months.
Impractical for Short Bare or Ineffectively Coated Pipelines	At least once every 3 calendar years not to exceed 39 months.
	SUPPLEMENTAL TESTING
Foreign Crossing Interference	Initially and as required, if survey done on recurring basis indicates the need.
Soil Resistivity	Initially for magnesium anode or impressed current ground bed installations.
Current Requirement	Initially and as required to determine current density, coating condition and cathodic protection sizing.
Deep Ground Bed Data	Initially to record all ground bed data during installation.
Deep Well Anode Performance	Initially and as required to record anode current outputs and look for ground bed deterioration.
Galvanic Anode Record	Initially to record all data during installation.

Rectifier Efficiency	Initially and as required.
Close Interval Survey	Perform close interval survey or comparable technology as required when annual potential surveys show deficiencies in cathodic protection.

Appendix 6.05A
DEFINITIONS FOR CATHODIC PROTECTION [195.553]

Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.

Buried means covered or in contact with soil.

Direct assessment means an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.* , external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

External corrosion direct assessment (ECDA) means a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

You means operator.

ELECTRICAL ISOLATION
Hazardous Liquid Pipeline O&M Procedure #6.06

Primary Ref: 49 CFR 195.575	**Updated: Jan 2016**

1. REFERENCE

195.575, PHMSA Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs [March 2010].

2. PURPOSE

The purpose of this procedure is to outline requirements for electrical isolation of buried, in contact with the ground, or submerged pipeline facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (200) _______________ is responsible for implementation of this procedure.

4. GENERAL

4.1 The company must electrically isolate each buried or submerged pipeline from other metallic structures, unless it is electrically interconnected and cathodically protect the pipeline and the other structures as a single unit. [195.575(a)]

4.2 The company must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. [195.575(b)]

4.3 The company must inspect and electrically test each electrical isolation to assure the isolation is adequate. [195.575(c)]

4.4 In order to successfully and efficiently cathodically protect a buried or submerged pipeline system, it is vital that the system be electrically isolated from foreign structures. EXCEPTION: When a pipeline terminates on an offshore platform, and both the pipeline and the platform are operated by the Company, electrical isolation of the pipeline from the jacket is not normally recommended. The platforms and pipeline riser are protected as a combined entity. In some cases, an isolating device may sometimes be installed near the pig launcher (or receiver), but provision to short the device should be made.

4.5 Electrical isolating devices are installed on pipeline systems to control current flow to or from foreign structures. Insulating devices are also used to isolate sections of the same pipeline (which can facilitate the application of cathodic protection) and to isolate the pipeline from a casing or structural supports attached to other unprotected metallic structures.

4.6 No electrical isolating device shall be installed or removed in a closed area that could retain an explosive mixture unless provisions are made to prevent electrical arcing. This includes situations similar to insulating flange kits in vaults.

5. STANDARD ELECTRICAL ISOLATION METHOD

5.1 Flange Insulation

Mating standard raised face flanges, may be made an insulating device by installing an insulating kit in the flange. An insulating kit consists of an electrically non-conductive gasket, non-conductive sleeves to encase the studs, and non-conductive washers for both nuts of a stud. Steel washers should also be placed immediately under nuts to protect the insulating washer from being crushed during torquing.

When welding the insulating flange unit or the weld type insulated coupling into the line, care shall be exercised to be sure that the insulation is not damaged by the current “arc” which could occur from welding. This can be achieved by moving the ground cable to the same side of the flange set as the electrode cable thus eliminating current “arc” across the insulating flange during welding.

5.2 Monoblock Insulating Joints

Monoblock insulating joints are factory-assembled insulating assemblies which are welded into a pipeline; they have no serviceable parts.

5.3 Insulated Unions

Insulating unions are usually used for small diameter (3 inches (7.62 cm) or less) piping attachments which required electrical insulation.

5.4 Casing Centralizers and End Seals

Non-conductive centralizing devices are attached to pipelines where the carrier pipe passes through a cased crossing. These centralizers prevent electrical contact between the casing and the carrier pipe. Casing end seals prevent water or soil from entering the annular space between the carrier pipe and casing and causing an "electrolytic" short between the casing and pipe.

5.5 Other Devices

Frequently, high-pressure laminated (e.g., micarta) dielectric blocks or neoprene rubber pads are used to electrically isolate a pipeline from supports or other structural appurtenances which are not a part of the cathodically protected pipeline.

6. CASED CROSSINGS

Whenever possible, casing installations should be avoided. In some cases, however, railroad or public highway regulations require the installation of a casing for railway right-of-way or road crossings. When casings are required, the carrier pipe must be electrically isolated from the casing.

The corrosion engineering or designee should review PHMSA "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, March 2010" and make a determination if filling the casing is appropriate on a case by case basis.

7. PROCEDURE

7.1. Location of Insulating Devices

Generally, insulating devices should not be buried in the soil (or submerged), but located in pipe above ground or in a vault. At the termination of a pipeline, the insulating device should be as close as possible to the point where the pipeline comes above grade. Laterals, pressure taps, etc. should have insulating devices located as close as possible to the cathodically protected pipeline.

Electrical isolation equipment or devices should be installed to isolate structures from the following locations:

7.1.1 at the termination points of a pipeline system and entering or leaving a pump or compressor station;

7.1.2 at exchanges or interconnect points with other pipeline companies;

7.1.3 at connection points for gas operated control lines, electrical conduit attachments or instrumentation connections;

7.1.4 at established aboveground Company facilities;

7.1.5 on the downstream side of metering stations;

7.1.6 between the casing and carrier pipe;

7.1.7 between supporting structures and the carrier pipe on bridge crossings;

7.1.8 between all metallic structures not requiring cathodic protection, such as metal valve boxes, conduit, fences, etc. and a cathodically protected pipeline;

7.1.9 where fault currents or lightning can affect the pipeline, such as close to electrical transmission tower footings or ground cables;

7.1.10 or, at points where dissimilar metals are attached to the pipeline, provided that both the pipeline and the dissimilar metal are buried or submerged.

7.2 Repairs

Prompt remedial action (at least prior to the next required test) shall be taken where the loss of electrical isolation causes a failure to meet the applicable cathodic protection criterion or causes detrimental effects to a foreign structure.

7.2.1 The remedial action should be restoration of electrical isolation; in some cases, other measures (such as increasing the amount of cathodic protection current applied to the pipeline) can be taken that shall adequately protect foreign structures.

7.2.2 If the loss of isolation does not require prompt action, the insulating device should be repaired at the earliest opportunity in conjunction with other scheduled maintenance or modifications to the piping system.

7.3 Shorted Casing

Pipelines in casing where isolation was intended when installed, shall be evaluated and acted upon as outlined below:

7.3.1 If casing-to-soil potential is within 100 millivolts of the carrier pipe-to-soil potential, further testing is required to determine if electrical isolation exists.

7.3.2 Determine whether the situation is an “electrolytic condition” or a “metallic” shorted casing.

Note: Basically, an electrolyte is a liquid or semi-liquid substance in which an electrical current shall flow.

7.3.3 Electrolytic conditions in casings require no remedial action.

7.3.4 Retest the casing when a future survey indicates a significant decrease in potential separation from the previous test, at a casing where the test procedures previously indicated an “electrolytic condition.”

7.3.5 Attempt to clear a shorted casing promptly, within 6 months, after discovery by implementing the following actions:

7.3.5.1 Inspect the test wires for possible direct shorts, and repair as necessary.

7.3.5.2 If practical, excavate the ends of the casing and inspect the clearance between the casing and carrier pipe. If contact exists, reposition the carrier pipe and replace damaged insulators and end seals.

7.3.5.3 When a shorted casing cannot be cleared by implementing the above actions, consider installing new carrier pipe insulators when the pipeline segment is out of service for other scheduled repair, replacement, or modification; or consider filling the casing/pipe annulus with high dielectric casing filler.

7.3.5.4 Remove shorted casing when convenient.

7.3.5.5 Pipe wall metal loss may be confirmed by electromagnetic flux leakage devices, ultrasonic smart pigs, or other detection.

7.3.6 Casings that are determined to be shorted and impractical to promptly correct, shall be monitored by using leak detection instruments as shown in Table 6.06A. If a leak is found, it must be repaired immediately.

7.4 Inspection and Testing

Testing and inspection frequency requirements for electrical isolation and shorted casing are shown in Table 6.06A. All devices described in section #7.1 shall be inspected and tested.

7.5 Close Interval Surveys

Close interval surveys shall be conducted if the electrical isolation status of the pipeline can not be determined using other standard corrosion and electrical procedures described in the O&M manual.

8. RELATED PROCEDURES

3.05 Crossing of Company Pipelines
5.01 Continuing Surveillance
6.05 Cathodic Protection/External Corrosion Control

9. RECORDS

9.1 Document all electrical isolation and casing vapor leak testing.
Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

9.2 Record the tests on possible shorted casing. Retain the record for each shorted casing until it is removed.

TABLE 6.06A

TEST FREQUENCIES FOR ELECTRICAL ISOLATION AND SHORTED CASINGS

TEST:	FREQUENCY:
Electrical Isolation:	Once each calendar year at intervals not exceeding fifteen (15) months. Usually conducted as part of the annual CP survey.
Shorted Casings:	Twice each calendar year at intervals not exceeding 7½ months. (Flame Ionization Inspection.)

IMPRESSED CURRENT POWER SOURCE - INSPECTION
Hazardous Liquid Pipeline O&M Procedure #6.07

Primary Ref: 49 CFR 195.573	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.573(c).

2. PURPOSE

   The purpose of this procedure is to establish the requirements for inspecting and checking impressed current cathodic protection systems.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (206) _______________ is responsible for scheduling, inspection, and documentation as required by this procedure.

4. GENERAL

   4.1 Rectifiers and ground beds provide a driving voltage and current greater than can be produced by galvanic anodes. Compared to sacrificial anodes, this type of protection covers a much larger area and gives greater flexibility to the cathodic protection system by allowing control of the current output.

   4.2 The rectifier ground bed method develops an electrolytic cell making the structure to be protected the cathode, and the ground bed of the rectifier the anode. (Reversing the polarity shall cause rapid corrosion of the pipeline.)

   4.3 To gain the greatest benefit from corrosion control, it must be a continuous process. The rectifier shall not give protection if it has not been properly installed. Therefore, proper installation of any rectifier is of utmost importance and shall serve to prevent trouble later.

5. PROCEDURE

   5.1 Inspect each cathodic protection rectifier or other impressed current power source at least six (6) times each calendar year, but at intervals not exceeding 2½ months.

   Where impressed current to a company owned pipeline or facility is provided by others, i.e., a third party or other operator, a request to a responsible individual shall be made for rectifier readings and maintenance records.

5.2 Conduct the following tasks during each inspection:

5.2.1 Inspect each impressed current power source and its components for proper operation. Follow manufacturer's instruction for assistance.

5.2.2 Determine and document the D.C. volts and amperes as applicable on form #6.07A or equivalent.

5.3 Take prompt remedial action to correct any deficiencies indicated by the monitoring. Any necessary remedial action must be taken prior to the next inspection.

5.3.1 Determine if unusual current and voltage readings are the result of rectifier malfunctions or due to changed pipeline protection requirements.

Potential rectifier problems include the following:

- Zero current and voltage output - No AC input, open circuit within the rectifier
- Zero current output with unchanged voltage output - Open fuse in output circuit, faulty connections, open positive or negative lead, failed anodes
- Increase in current output with unchanged voltage - System addition, short to underground structures, major coating damage
- Decrease in current output with unchanged voltage - Installation of inline insulators, anode deterioration, dis-connection of system component, gas blockage, dry or frozen ground.
- Significant changes in both voltage and current outputs - If anode to structure resistance is normal then there is a problem with rectifier, if anode to structure resistance is not normal then the problem is outside the rectifier.
- Normally, a change in current readings of 10-15% or more would be considered an "abnormal operating condition" (AOC) and should be investigated by the corrosion engineer or designee.

5.3.2 Notify the (207) ______________ of malfunctioning rectifiers.

5.3.3 Notify the (208) ______________ of indications of changed pipeline C.P. requirements.

6. RELATED PROCEDURES

2.01 Record Keeping
5.01 Continuing Surveillance
6.05 Cathodic Protection/External Corrosion Control
6.08 Cathodic Protection Records

7. RECORDS

7.1 Record all survey and test results on a special form or chart for that purpose.

7.2 Maintain the records of power source inspections and efficiency calculations.

7.3 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [CP survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

CATHODIC PROTECTION MAPS AND RECORDS
Hazardous Liquid Pipeline O&M Procedure #6.08

Primary Ref: 49 CFR 195.266, 195.404	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Section 195.266(f) and 195.404.

2. PURPOSE

The purpose of this procedure is to establish the methods by which records shall be maintained showing the location and type of cathodic protection for all pipelines operated by the Company.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (214) _______________ is responsible to maintain the Corrosion Control Records for the life of the pipeline facilities.

4. PROCEDURE

4.1 The following is a minimum list of construction records that shall be maintained for the life of the pipeline. [195.266]

- The total number of girth welds and the number nondestructively tested including the number rejected and the disposition of each rejected weld. Records used to demonstrate weld acceptability shall be tested over the entire circumference of the welds
- The amount, location; and cover of each size of pipe installed
- The location of each crossing of another pipeline
- The location of each buried utility crossing
- The location of each overhead crossing
- The location of each valve and corrosion test station

4.2 In addition, the company shall maintain drawings, plat sheets, maps, or other records for each pipeline system and facility showing the following:

- Location of cathodically protected piping, tanks, cathodic protection facilities, and neighboring structures bonded to the system
- Sacrificial Anode Bed
- Impressed Current Rectifier
- Bonded Impressed Current
- Rectifier

- Insulation Flange
- Insulating Joint
- Bonds (critical, noncritical, and interference)
- Ground Bed - Conventional (surface)
- Ground Bed - Well Type (vertical)
- Cathodic Protection (CP) or Electrolysis Test Stations (ETS) and monitors

4.3 For pipelines in the company "Integrity Management Program" (IMP), review IMP procedures for other potential map and records data that might be required.

4.4 Also, refer to procedure #2.01, Record Keeping, for additional information.

5. RELATED PROCEDURES

2.01 Record Keeping
5.01 Continuing Surveillance
Section 6 (all procedures)

6. RECORDS

The maps and records are to be retained for the life of the facility, structure, or pipeline.

Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

EVALUATION OF BARE, BURIED OR SUBMERTED UNPROTECTED PIPELINES
Hazardous Liquid Pipeline O&M Procedure #6.09

Primary Ref: 49 CFR 195.573	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.573.

2. PURPOSE

The purpose of this procedure is to establish the inspection practices for bare, buried, in contact with ground, or submerged unprotected pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (221) _______________ is responsible for implementing the requirements of this procedure to evaluate the external corrosion of bare unprotected pipe.

4. GENERAL

4.1 The company shall reevaluate unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

- Determine the areas of active corrosion by electrical survey
- Where an electrical survey is impractical, the company shall determine areas of active corrosion by the following other means;
  - ✓ review and analysis of leak repair and inspection records
  - ✓ corrosion monitoring records
  - ✓ exposed pipe inspection records
  - ✓ pipeline environment.

4.2 The company shall maintain a continuing program of examination and recording the results of the inspection of bare, unprotected pipelines is mandatory for evaluating the effects of external corrosion.

4.2 It is intended that examinations shall monitor the effects of external corrosion and, where necessary to protect the integrity of the pipeline, and dictate the installation of cathodic protection equipment.

4.3 Corrosion, leaks, and defects may be safety related conditions.

4.4 Pipeline MOP <u>cannot</u> be increased on pipeline sections that have not been electrically inspected.

4.5 All bare, buried or submerged unprotected pipelines must have had an initial electrical inspection by the dates given in 195.573(b) and shown in the table below:

For the period in the first column, the second column prescribes the frequency of evaluation.

Period:	Evaluation Frequency:
Before December 29, 2003	At least once every 5 calendar years, but with intervals not exceeding 63 months.
Beginning December 29, 2003	At least once every 3 calendar years, but with intervals not exceeding 39 months.

5. <u>PROCEDURE</u>

5.1 After the initial evaluation, bare, below-ground unprotected pipelines shall be re-evaluated at least once every three calendar years, not to exceed 39 months. In areas where active corrosion is found, cathodically protect them, and take remedial measures prior to the next inspection.

5.2 Areas of possibly active corrosion shall be evaluated by electrical survey or by a review of the leak history and leak surveys of the corrosively active areas.

5.3 The following areas where there is active corrosion shall be given high priority for remediation.

- Most areas within the boundary limits of any incorporated or unincorporated city, town, or village. Any residential or commercial area, such as a subdivision, business or shopping center, or community development
- Areas in which the pipeline closely parallels or crosses underground sewers or other utility lines
- An area where the pipeline lies within 100 yards of the following:
    1) A building that is intended for human occupancy
    2) A small well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

5.3 Areas confirmed to be corrosively active shall be cathodically protected.

5.4 The District Engineer shall review the pipeline MOP (see Procedure 8.01) for possible revision and/or recommend pipeline repair requirements.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR 195 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (49CFR 195 currently referenced edition).

5.5 Review the pipeline per the criteria shown on Form 6.09A. Areas with category 3 corrosion shall be cleaned, coated, repaired, replaced, and/or cathodically protected.

6. RELATED PROCEDURES

2.01 Record Keeping
5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
6.03 External Protective Coating
8.01 Maximum Operating Pressure
9.01 Repair Procedures

7. RECORDS

7.1 The "Unprotected Pipeline Surveillance Report" (Form 6.09A) or equivalent may be used for documentation.

7.2 Complete forms from related procedures wherever active corrosion is identified.

7.3 Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

CORROSION PROGRAM – DISTRICT OFFICE REVIEW
Hazardous Liquid Pipeline O&M Procedure #6.10

Primary Ref: 49 CFR 195 Subpart H	**Updated: Jan 2016**

1. REFERENCE

   None.

2. PURPOSE

   The purpose of this procedure is to describe the role of the (227) _______________ in implementing and/or monitoring the corrosion control program. It also provides for flexibility in location of records and staffing.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (228) _______________ is responsible for implementation of corrosion control programs through the company.

4. GENERAL

   The (229) _______________ shall verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.

5. PROCEDURE

   The (230) _______________ shall provide overall guidance in corrosion control activities.

   5.1 Reviews field corrosion reports and data.

   5.2 Recommends corrective action when requested.

   5.3 Prepares a yearly report which highlights some pertinent corrosion control activities of the company, which should include as a minimum, the following:

   5.3.1 Annual CP system survey status.

   - Number of CP readings below criteria
   - Qualification records in the file for person conducting the annual CP survey
   - Number of test stations adequate? And number of test stations installed or repaired

- Test stations entered on CP maps
- Number of ground beds installed, improved or abandoned, with the locations and reasons for such activities
- Number of foreign line interference tests conducted and their results
- CP survey recommendations, if any

5.3.2 Miscellaneous Corrosion Activities for Review.

- Miles of "close interval survey" (CIS) conducted
- Miles of "direct current voltage gradient" (DCVG)
- Number of rectifiers repaired and new rectifiers installed. The location and the reason for such activities.
- Miles of pipelines recoated, and the location and the reason for recoating
- Maintenance painting done on above ground piping and structures, including breakout tanks
- External exposed pipe reports? If yes, what are the results?

5.3.3 Miscellaneous Corrosion Activities for Internal Corrosion.

- Fluid analysis to test for corrosive properties
- If corrosive properties, have the corrosive properties been mitigated? If yes, how are the corrosive properties mitigated? (Removal of impurities, chemical injection, coupon monitoring)
- Results of chemical injection? Is the person conducting chemical injection qualified under the company OQ plan?
- Results of coupon monitoring? Is the person conducting coupon monitoring qualified under the company OQ plan?
- Internal exposed pipe reports? If yes, what are the results?

5.3.4 Use form #6.10, "Annual Corrosion Control Review" or equivalent to document this review.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
6.02 Internal Corrosion
6.03 External Protective Coating
6.04 Examination of Buried Pipeline
6.05 Cathodic Protection
6.06 External Corrosion - Electrical Isolation
6.07 Impressed Current Power Source Inspection
6.08 Cathodic Protection Records
6.09 Evaluation of Bare, Buried, or Submerged Unprotected Pipelines

7. RECORDS

Corrosion control records required by corrosion procedures are to be kept at the District Office. Use form #6.10, "Annual Corrosion Control Review" or equivalent to document this review

Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by the 195 subpart H, Corrosion Control (O&M procedures #6.01 through #6.10), must be maintained to demonstrate the adequacy of the company corrosion control procedures. These records must be maintained for five years, except records related to 195.569 [exposed pipe reports], 195.573(a) and (b) [cp survey and protection], 195.579(b)(3) [corrosion inhibitors], and 195.579(c) [internal corrosion inspection] must be retained for as long as the pipeline remains in service.

INSPECT AND MAINTAIN EMERGENCY VALVES
Hazardous Liquid Pipeline O&M Procedure #7.01

Primary Ref: 49 CFR 195.258, 195.260, 195.420	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.258, 195.260, 195.420, CSPA 51015.4, 51016

2. PURPOSE

   The purpose of this procedure to provide guidelines for valve inspection and maintenance to ensure that all valves are in good working order at all times.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (237) _______________ is responsible for the inspection of the valves.

4. GENERAL

   4.1 Any valve that is necessary for the safe operation of a pipeline system must be maintained to ensure that it is in good working order at all times. The company shall develop and maintain a master list of critical valves as shown in the PSOM.

   4.2 Valves necessary for the safe operation of pipeline system shall be determined by the (238) _______________ .

   4.3 The inspection and partial operation of valves other than those described in 4.2 above, shall be at the discretion of the (239) _______________ .

   4.4 Each mainline valve must be inspected and partially operated at least twice per calendar year, not to exceed 7½ months.

   4.5 Each valve must be protected from unauthorized operation and from vandalism. The company shall use one or more of the following security techniques to prevent unauthorized operation and vandalism.

   - Location inside a locked building, enclosure, or fence
   - Locks on equipment
   - Removal of valve handles or hand wheels
   - Other options may be used if reviewed and documented and described in the PSOM

Vandalism history shall be evaluated during the continuing surveillance reviews and may dictate which security method is prudent. The protection from vandalism provided at each valve inspected should be adequate to prevent the level of vandalism experienced at the site.

Valves that may be exposed to outside force damage such as vehicular damage should have some type of protection surrounding them. Typically this would be bollards.

4.6 Necessary personnel shall be notified prior to operating any valve that may significantly affect the normal operation of those locations. Other concerned personnel shall be notified when the inspection is complete.

5. PROCEDURE

5.1 The valve inspection and maintenance should include but not be limited to:

5.1.1 Grease or lubricate valve if applicable according to manufacturer’s recommendations.

5.1.2 Fully operate the valve, if possible; if not, partially operate the valve to check its operation (do not use “cheater” devices). All listed valves to shall have an indicator or valve stem, to clearly show the valve position.

5.1.3 Operate power operated valves by introducing the normal power source to the operator.

5.1.4 Check above-ground valves for atmospheric corrosion.

5.1.5 Ensure the valve environment shall not interfere with the operation of the valve or prevent safe personnel access at any time of the year.

5.1.6 Notify the control room and/or the appropriate person when the valve inspection is complete.

5.1.1 The company shall use specific valve manufacturer's recommendations to develop additional maintenance procedures as appropriate. These valve specific procedures are shown in appendix #7.01A. Specific procedures should include type of lubrication to use, amount of lubrication to use, and other manufacturer’s maintenance recommendations, etc.

5.1.6 Use form 7.01A or equivalent to document the inspection.

5.2 Maintain valves, position indicators, internal or external thermal relief, and operators in operating condition. Any necessary repairs should be done promptly, but must be completed before or during the next planned inspection.

5.3 Protect normally closed valves from conditions which could affect proper operation or cause deterioration.

5.4 Perform inspection and maintenance on frequently operated valves more often if needed.

5.5 Secure valves requiring locking devices to prevent unauthorized operation.

5.6 Inspect above-ground piping or fabrications associated with a valve outside of plant yard for atmospheric corrosion when the valve is given its inspection. Maintain as appropriate.

6. <u>RELATED PROCEDURES</u>

5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
14.01 Valve Security

7. <u>RECORDS</u>

7.1 The "Emergency Valve Inspection Report", (Form 7.01A) or equivalent must be used for documenting the inspections.

7.2 Inspection records are to be retained for at least two (2) years.

Primary Ref: 49 CFR 195.406, 195.428	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.406, 195.428, and ASME B31.4 section #452.2

2. PURPOSE

To establish requirements for the inspection, testing and capacity verification of each pressure limiting device, relief valve, pressure regulator, overfill protection system or breakout tanks or other item of pressure control used in hazardous liquid pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (245) _______________ is responsible for the inspection, maintenance, and mechanical condition of all pressure limiting devices, relief valves, pressure regulators or other items of pressure control.

4. GENERAL

4.1 This procedure outlines inspection, test frequency, documentation, capacity verification requirements, and specifies applicable records. The company shall test each pressure limiting device, pressure regulator, pressure relief, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.

4.2 Disassembly of pressure regulators and relief valves for internal inspection is not required to satisfy the requirements of this procedure.

4.3 The pipeline system must have pressure relief or other suitable devices to ensure that the maximum operating pressure (MOP) is not exceeded by more than 10% during surges or other variations from normal operations.

4.4 Breakout tanks must have an overfill protection built according to section 5.1.2 of API 2510 system if the tank is installed, built or significantly modified after October 2, 2000. After October 2, 2000, the requirements of this procedure and 49 CFR 195.428 for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems. installation of an overfill protection system installed according to section 5.1.2 of API 2510 for aboveground breakout tanks that are constructed or significantly altered according to API 2510 after October 2, 2000.

For aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed after October 2, 2000, an overfill protection system shall be installed according to API 2350. The company need not comply with any part of API 2350 for any particular breakout tank if the company can justify in the procedures or documentation why compliance with API 2350 is not necessary for safety of the tank.

5. PROCEDURE

5.1 Frequency of Inspection

5.1.1 For pipelines in hazardous liquid service, (non highly volatile hazardous liquid) inspect and test pressure limiting devices, relief valves (including thermal relief valves), pressure regulators or other items of pressure control regulators (including high pressure shutdown devices) once each calendar year with intervals not to exceed 15 months. This inspection includes functionality tests on back-up or secondary over-pressure safety devices, if applicable.

5.1.2 If equipment or physical conditions change between scheduled inspections and tests, perform the appropriate items required by this procedure to assure continued compliance.

5.1.3 Overfill protection and/or relief systems, on in-service breakout tanks shall be inspected at intervals not to exceed 5 years.

5.1.3 For HVL pipelines, inspect and test pressure limiting devices, relief valves (including thermal relief valves), pressure regulators or other items of pressure control regulators (including high pressure shutdown devices) twice each calendar year with intervals not to exceed 7 ½ months. This inspection includes functionality tests on back-up or secondary HVL over-pressure safety devices, if applicable.

5.1.4 For pipeline maintenance scheduling, the company shall use the “Compliance Assurance System” (CAS) or equivalent tracking system. The CAS system is located online at the following website: www.complianceservicesinc.net.

5.2 Regulator Inspection

5.2.1 Inspect and test each pressure regulator to assure that:

5.2.1.1 It is in good mechanical condition.

5.2.1.2 It is adequate from the standpoint of capacity and reliability of operating for the service in which it is employed.

5.2.1.3 The manual inspection of over pressure protection devices shall include the following in the inspection documentation.

- Set point
- Span
- Zero of the control device
- As found and as left

5.2.1.4 The inspection shall include testing of applicable electronic control devices, such as transducers, station logic controller and communications linkage between components.

5.2.1.4 It is properly protected from external conditions or environment that might prevent proper operation.

5.2.1.5 Its control system lines are properly supported and protected.

5.2.1.6 Its vent line is terminated in a safe location to prevent a hazardous condition and protected to minimize possible plugging with items such as snow, ice, or insects.

5.2.2 Repair or replace defective or inadequately sized equipment or components prior to the next inspection.

5.3 Relief Device Inspection Including Thermal Relief Devices

5.3.1 Inspect and test each pressure relief device to assure that:

5.3.1.1 It is in good mechanical condition.

5.3.1.2 It opens at the proper pressure. Actuate the "pilot operated" valve piston (main valve) in addition to the pilot.

5.3.1.3 Its vent line is free of obstructions, is protected to prevent entrance of moisture or plugging with items such as snow, ice or insects.

5.3.1.4 Its control line is properly supported and protected.

5.3.1.5 It has adequate capacity. The capacity review shall include manufacturer data to derive factors affecting the calculation of capacity and/or direct measurement during full flow conditions. The calculated capacities shall include the effect of piping size and length associated with the relief device.

5.3.2 If relief valve capacity test is not feasible, calculate the required capacity or review past calculations. Indicate review on Form 7.02A or equivalent. Make an on-site review and verification of the facilities and pressures at the time the relief valve is to be tested. Check to see that the correct valve is installed, no changes have been made to the valve, and operating and/or relief flows and pressures are still the same.

5.3.3 Initiate appropriate measures to increase relief capacity promptly if existing capacity does not meet requirements. Appropriate measures to increase relief capacity shall be documented in a report or equivalent and include a schedule for timely action.

5.3.4 Initiate appropriate measures promptly to provide overpressure protection if a defective valve is observed. Appropriate measures to provide adequate protection shall be documented in a report or equivalent and include a schedule for timely action.

5.3.5 Remedial work required on relief valves must be completed (prior to the next inspection).

5.3.6 Secure isolating valves, when installed, in the open position after each relief valve inspection and test. Lock each isolating valve not located within a locked building to avoid accidental or malicious closing.

5.4 Shutdown Switches

5.4.1 Inspect and test each high pressure shutdown switch to assure that it is in good mechanical, electrical or pneumatic condition.

5.4.2 Inspect connecting lines and conduits for tightness and adequate support.

5.4.3 Test each high pressure shutdown switch and associated control system to assure that it actuates a shutdown at the required set pressure.

5.5 Relief and Shutdown Devices Set Point

5.5.1 For any hazardous liquid pipeline system, establish relief valve and shutdown switch set points so that the maximum pressure, including buildup, shall not exceed the maximum operating pressure plus 10% in any part of the system.

5.6 Breakout Tank Overfill Protection System Inspection and Testing

5.6.1 The testing should duplicate an actual high liquid level situation as realistically and as closely as possible; however, the test shall not require filling the tank above its normal capacity. Generally, this test shall be conducted by simulating conditions that activate the detector and alarm/signal.

Breakout Tanks under the Scope of this Procedure:

- Facility ABC breakout tank located at outlet of the facility

The detailed procedures for inspection and testing of these breakout tanks are listed below:

1) Open the switch mechanism and inspect for moisture, corrosion, and cleanliness of the contact points. For the tanks where the switch is located inside the tank vapor space, access shall require confined space training and permit.
2) From the outside, without entering the tank, visually inspect the internal mechanism to ensure that the displacers are hanging freely and cables are not kinked or damaged.

3) Thoroughly inspect the internal mechanism and the detector setting whenever the tank is out of service for internal work or inspection.

5.6.2 The source of alarms/signals shall be determined and corrected as quickly as possible.

5.6.3 Device set points must prevent the breakout tank from being over-pressured.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
8.01 Maximum Operating Pressure (MOP)
14.01 Valve Security

7. RECORDS

7.1 Document inspection and testing of pressure regulators and relief devices on Forms 7.02A, and 7.02B, or other equivalent forms. Documentation shall include the recording of as-found and as-left settings during the inspection.

7.2 Document capacity confirmations and verifications of calculations.

7.3 Document reasons for needed changes to set points.

7.4 These records are to be retained for at least two years.

MAXIMUM OPERATING PRESSURE (MOP)
Hazardous Liquid Pipeline O&M Procedure #8.01

Primary Ref: 49 CFR 195.106, 195.110, 195.208, 195.406	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.106, 195.110, 195.208, 195.406.

2. PURPOSE

To outline the responsibility for establishing the maximum operating pressure (MOP) of each pipeline segment and the related operating requirements.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (251) _______________ is responsible to establish MOP on pipeline facilities and the (252) _______________ is responsible to maintain the operating pressure of the pipeline systems at or below the established MOP.

4. GENERAL

4.1 Except for surge pressures and other variations from normal operations, no person may operate a hazardous liquid pipeline or pipelines listed in Procedure 6.03 (4.1(a)) at a pressure that exceeds any of the following:

4.1.1 The internal design pressure of the pipe determined in accordance with the following. (For pipelines undergoing conversion of service, see paragraph 5.4 in Procedure 12.02.):

P = (2 St/D) x E x F where,

P = Internal design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with 195.106. Note that "S" is the specified minimum yield stress (SMYS) of the pipe if it is known. If SMYS is unknown, it is determined per 195.106(b).

If the yield strength of the pipe is unknown and is not tensile tested as provided in paragraph 195(b), the company is required to use yield strength of 24,000 p.s.i. (165,474 kPa).

t = Nominal wall thickness of the pipe in inches (millimeters) if known. If this is unknown, it is determined in accordance with 195.106(c).

If the nominal wall thickness to be used in determining internal design pressure under paragraph (a) of this section is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness, only 10 individual lengths or 5 percent of all lengths, whichever is greater, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 20 inches (508 mm) nominal outside diameter, nor more than 1.11 times the smallest measurement taken on pipe that is 20 inches (508 mm) or more in nominal outside diameter. [195.106(c)]

The minimum wall thickness of the pipe may not be less than 87.5 percent of the value used for nominal wall thickness in determining the internal design pressure under paragraph (a) of this section. In addition, the anticipated external loads and external pressures that are concurrent with internal pressure must be considered in accordance with §§ 195.108 and 195.110 and, after determining the internal design pressure, the nominal wall thickness must be increased as necessary to compensate for these concurrent loads and pressures. [195.106(d)]

D = Nominal outside diameter of the pipe in inches (millimeters).

E = Seam joint factor determined per the following Table:

Seam Joint Factors		
Specification	**Pipe Class**	**E**
ASTM A 53	Seamless Electric resistance welded Furnace lap welded Furnace butt welded	1.00 1.00 0.80 0.60
ASTM A 106	Seamless	1.00
ASTM A 333/A333M	Seamless Welded	1.00 1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API 5L	Seamless Electric resistance welded Electric flash welded Submerged arc welded Furnace lap welded Furnace butt welded	1.00 1.00 1.00 1.00 0.80 0.60

Note 1: All pipe specifications listed above are to be the 49 CFR 195 currently referenced edition.

Note 2: The seam joint factor for pipe which is not listed above must be approved by the U.S. Secretary of Transportation.

F = A design factor of 0.72, except that a design factor of 0.60 is used for pipe, including risers, on a platform located offshore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as a part of welding, to a temperature higher than 900º F (482º C) for any period of time or over 600º F (316º C) for more than 1 hour.

4.1.2 The design pressure of any other component of the pipeline. Note that butt-welding type fittings must meet the end preparation and bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75 (49 CFR 195 currently referenced edition).

4.1.3 Eighty percent (80%) of the test pressure for any part of the pipeline which has been pressure tested per Procedure 15.01.

4.1.4 Eighty percent (80%) of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under 195.304.

4.1.5 For pipelines under 195.302(b)(1) that have not been pressure tested under Procedure 15.01, 80% of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

4.1.6 A pipeline may not be operated at a pressure greater than 100 PSIG (689 kPa) if it contains supports or braces welded directly to the pipe.

4.2 No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under section 4 of this procedure and 195.406. The company must provide adequate controls and protective equipment to control the pressure within this limit.

4.3 Anticipated external loads such as earthquakes, vibration, and thermal expansion and contraction must be provided for. Section 419 of ASME/ANSI B31.4 (49CFR 195 currently referenced edition) must be followed. Note that external loads can lower the MOP if the induced pipe stresses are sufficiently high.

5. PROCEDURE

5.1 Establish the MOP of all existing and new pipeline facilities. The (253) _______________ shall communicate the MOP to the appropriate parties.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR 195 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A

Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (49CFR 195 currently referenced edition).

5.2 Control operating pressures at or below established MOP for all pipelines at all times, except during surges of other variations from normal operations when 110% of MOP is allowable temporarily during the transient condition.

5.3 No person shall operate or cause action which shall operate any pipeline section in excess of its established MOP.

5.4 Implement repairs, modifications, or additions to a segment of pipeline so that the MOP of the segment is maintained through the use of approved materials, construction and testing methods.

6. RELATED PROCEDURES

8.02 Operating Pressure Limits-Maintenance and repair
15.01 Pressure Testing

Primary Ref: 49 CFR 195.106, 195.110, 195.208, 195.406	**Updated: Jan 2016**

7. RECORDS

7.1 Retain operating logs and/or pressure charts for three (3) years.

7.2 Submit all as-built documents to the (254) _______________ to update the drawings and confirm the MOP.

7.3 Maintain as-built documents for the life of the pipeline facility.

7.4 Record MOP and basis of determination in the operations description portion of the system specific System Operations Manual. Record pertinent data using the Pipeline Qualification Record form #8.01A and MOP calculation form #8.01B.

7.5 Retain calculations used to determine the MOP in the pipeline historical file.

OPERATING PRESSURE LIMITS-MAINTENANCE & REPAIR
Hazardous Liquid Pipeline O&M Procedure #8.02

Primary Ref: 49 CFR 195.106, 195.422	Updated: Jan 2016

1. REFERENCE

   49 CFR, Sections 195.106 and 195.422(a).

2. PURPOSE

   To establish recommended maximum pressures at which a pipeline should be operated while maintenance, repairs, or other such activities are being performed.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (257) _______________ is responsible to establish and maintain the recommended safe operating pressure during pipeline maintenance or repair activities.

4. GENERAL

   4.1 A pipeline is considered to be damaged if a defect is believed to exist, or has been identified, which requires repair.

   4.2 A pipeline is considered undamaged if no defect exceeding the limits shown in "Repair Procedure" (Table 9.01-A) has been found, or after all known defects have been repaired.

   4.3 The pressure criteria in this procedure are based upon industry experience as opposed to mathematical analysis or empirical expressions predicting pipeline behavior. Such experience indicates that a pipeline which has been damaged and does not subsequently fail (rupture) probably shall not fail during the course of repair activities if the actual pressure in the pipe is reduced. With this consideration, the greater the pressure reduction, the lesser the probability that a pipe failure shall occur.

   4.4 To maximize the reduction of risk, activities should be accomplished at the lowest operating pressure possible if the opportunity exists to do so without having to implement extraordinary measures.

   4.5 Good engineering judgment and common sense may indicate the need for higher or lower pressures depending on the extent of damage to the pipeline, deliverability requirements or other circumstances.

   4.6 The Facility Engineer has the authority to use pressures above the recommended levels after making appropriate evaluations with approval from District Manager.

5. PROCEDURE

5.1 The Facility Engineer, or other designated and qualified individual, should be contacted prior to any repair or remedial work on a pipeline. That individual should review the entire situation taking into consideration such things as:

5.1.1 Pipeline location and exposure.

5.1.2 Pipeline wall thickness, pipe geometry, age, grade, etc.

5.1.3 Specific damage (dent, crack, gouge, groove, etc.), maintenance procedure, leak, or other reason for reducing pipeline operating pressure.

5.1.4 Commodity in pipeline, i.e., gas or liquid.

5.1.5 Existing operating pressure.

5.2 Severe defects should not be repaired under pressure unless there is sufficient experience to make a sound evaluation of the defect. In addition, the effect of any known secondary stresses should be considered.

5.3 Repairing or welding reinforcements directly to pipe which is under pressure can be done successfully. The following formula provides a recommended maximum pressure for the procedure:

$$P = \frac{2S(t - 3/32)(0.72)}{D}$$

(This formula is from the GPTC Guide for Gas Transmission and Distribution Piping Systems, December, 1999.)

5.4 Considering the above items, the individual shall make a recommendation for pressure reduction with safety as a primary element. Immediate temporary measures should be taken to protect life and property from hazards resulting from a leaking, defective or damaged pipeline with an injurious damage condition.

6. RELATED PROCEDURES

8.01 Maximum Operating Pressure (MOP)
9.01 Repair Procedures

7. RECORDS

None required by this procedure.

PIPELINE REPAIR PROCEDURES
Hazardous Liquid Pipeline O&M Procedure #9.01

Primary Ref: 49 CFR 195.230	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.120, 195.230, 195.234, 195.404, 195.416(h), 195.422 and 195.585.

2. PURPOSE

The purpose of this procedure is to define defects in steel pipeline and specify the acceptable method for their disposition.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (260) _______________ is responsible to confirm that all repairs are performed in accordance with this procedure. All repairs discussed in this procedure must occur prior to the next scheduled inspection.

4. GENERAL

4.1 Repair a pipeline as soon as possible whenever an injurious damage condition is found. In making the repairs to the pipeline system, the company shall insure the repairs are made in a safe manner and are made so as to prevent damage to persons and property.

4.2 An injurious damage condition (gouge, groove, dent, corrosion, or leak) is one that impairs the safety and serviceability of a pipeline and requires repair. See Table 9.01A for limits of damages.

4.3 Take immediate temporary measures to protect life and property from hazards resulting from a leaking, defective or damaged pipeline with an injurious damage condition.

4.4 Determine the repair method for an injurious condition according to the type of damage or defect.

4.5 Use the unpressurized repair alternate if either of the following two conditions exist:

4.5.1 Pipe geometry is deformed so it prevents proper installation of a pressurized repair.

4.5.2 Leakage makes pressurized repair unsafe.

4.6 A pressurized repair is one which is carried out while the pressure in the pipeline is higher than atmospheric.

4.7 If a pressurized repair is made, reduce the pressure of the line to the limits established by each repair method or as established in "Operating Pressure Limits – Maintenance and Repair", Procedure 8.02.

4.8 All repair methods established by this procedure are considered permanent. The use of a leak clamp is considered only as a temporary measure that may be taken to protect life and property.

4.9 After repairing a leak, verify that the leak has been contained and no additional leaks exist in the immediate area.

4.10 Except as provided in paragraphs 4.11 and 4.12 below, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

4.11 Paragraph 4.10 above, does not apply to:

4.11.1 Manifolds.

4.11.2 Station piping such as at pump station, meter stations, or pressure reducing stations.

4.11.3 Piping associated with tank farms and other storage facilities.

4.11.4 Crossovers.

4.11.5 Sizes of pipe for which an instrumented internal inspection device is not commercially available.

4.11.6 Offshore pipelines, other than main lines 10 inches (24.5cm) or greater in nominal diameter, that transport liquids to onshore facilities.

4.11.7 Other piping that the Administrator under 49CFR 190.9 finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

4.12 An operator encountering emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet paragraph 4.10 above, if the operator determines and documents why an impracticability prohibits compliance with paragraph 4.10 above. Within 30 days after discovering the emergency or construction problem the operator must petition, under 49CFR 190.9 for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

4.13 Passage of internal inspection devices [195.120]

Except as provided below, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced; must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Offshore pipelines, other than main lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities; and

(7) Other piping that the Administrator under §190.9 of this chapter, finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

If the company encounters emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet the requirement above, if the company determines and documents why impracticability prohibits compliance with section #4.13 of this procedure. Within 30 days after discovering the emergency or construction problem the company must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the company must modify that segment to allow passage of instrumented internal inspection devices.

4.14 Obtain all required qualification records as appropriate for personnel involved in the repair. The list below is an example of qualifications needed depending on the type of repair conducted.

- NDT inspector qualifications (ANST Level II or equivalent)
- Operator qualification records for repair activities (i.e., repairs, excavation, backfilling, exposed pipe inspections, coating application and repair, etc.)
- Welder's API 1104 welding qualification procedures and certificates and operator qualification module, "General Abnormal Operating Conditions" (AOCs).

5. PROCEDURE

No operator may use any pipe, valve, or fitting for replacement or repairing pipeline facilities unless it is designed and constructed as required by Part 195.

5.1 Preliminary Investigation

5.1.1 Inspect any exposed pipeline for leaks, impact damage, coating conditions, and external corrosion.

5.1.2 Visually inspect buried welds whenever the coating has been removed for any reason.

5.1.3 Make a preliminary assessment to determine the extent of the damage or defect. In most cases a visual inspection is sufficient. Use X-ray or other forms of inspection that could be considered helpful if conditions warrant.

5.1.4 Investigate to determine the cause of any leaks that are found.

5.1.5 Determine if a safety related condition exists and whether it should be reported. See Procedure 1.02 "Reporting of Safety Related Conditions".

5.2 Evaluation of Damage Extent

5.2.1 Make a precise evaluation of the extent of any damage or defect.

5.2.2 Compare the extent of any damage or defect against the limits established in Table 9.01A.

5.2.3 Confirm the damage as injurious to the facilities if its extent exceeds the limits established.

5.3 Repair of Corrosion Condition

5.3.1 General Corrosion:

Each segment of pipeline with general corrosion and with a remaining wall thickness less than that required for the maximum operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. However, the corroded pipe may be repaired by a method that reliable engineering test and analysis show can permanently restore the serviceability of the pipe. (Refer to Table 9.01A). If the pipeline is included in the integrity management program (IMP) then refer to specific limitations on pressure reduction, etc.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR 195 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (49CFR 195 currently referenced edition).

5.3.2 Localized Corrosion Pitting:

Each segment of pipeline with localized corrosion pitting to a degree where leakage might result must be repaired or replaced or the operating pressure reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits. Inspect the interior of the cutout and the ends of the remaining pipe for internal corrosion, record on Form 3.01B or equivalent. (Refer to Table 9.01A).

5.4 Repair of Imperfections and Damages

5.4.1 Except as provided in 5.4.2 below, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of specified minimum yield strength must be repaired as follows:

5.4.1.2 If it is not feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength, or

5.4.1.2 If it is not feasible to take the segment out of service, the pipeline can be repaired by a means that has been proven through engineering tests and analyses, to restore serviceability of the pipe.

5.4.2 Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a bolted full encirclement split sleeve of appropriate design over the imperfection or damage.

5.5 Repair of Welds

5.5.1 If it is feasible to take the segment of pipeline out of service, the weld must be repaired per Procedure 9.06.

5.5.2 A weld may be repaired in accordance with repair or removal of defective weld per applicable code and standard while the segment of transmission line is in service if:

5.5.2.1 The weld is not leaking;

5.5.2.2 The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the specified minimum yield strength of the pipe; and

5.5.2.3 Grinding of the defective area can be limited so that at least 1/8 inch (3.2mm) thickness in the pipe weld remains.

5.5.3 The method of repair for a defective weld, whether onshore or submerged, and cannot be repaired in accordance with 5.5.1 or 5.5.2 above, shall be determined on an individual basis.

For onshore pipelines, the weld can generally be repaired by installing a full encirclement welded split sleeve of appropriate design.

5.6 Repair of Leaks

5.6.1 If feasible, the segment of pipeline must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength, or

5.6.2 If it is not feasible to take the segment of pipeline out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design.

5.6.3 If the leak is due to a corrosion pit, the repair may be made temporarily by installing a properly designed bolt-on-leak clamp. However, as soon as it is feasible, the pipeline leak is to be repaired by the means stated in 5.6.1 or 5.6.2 above.

5.6.4 For submerged offshore pipelines and submerged pipelines in inland navigable waters, leaks may be repaired by mechanically applying a bolted full encirclement split sleeve of appropriate design over the leak.

5.6.5 Regardless of the repair method, ensure that the means of repair has been proven, through engineering tests and analyses, to restore serviceability of the pipe

5.6.6 All repairs must meet API 1104 (49CFR 195 currently referenced edition) or equivalent welding procedures.

5.6.7 All repairs performed must be tested and inspected

5.7 Use of Full Encirclement Welded Split Sleeves, or other Similar Devices

5.7.1 An “Alert Notice” was issued by the DOT/OPS on March 13, 1987, with regard to the welding of full encirclement repair sleeves. It cautioned operators not to use non-low hydrogen welding electrodes with cellulosic coating.

5.7.2 The recommendation in the repair weld procedure is E7018 low hydrogen electrode with vertical uphill weld progression.

5.8 Testing of Repairs:

5.8.1 Testing of replacement pipe:

The replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

5.8.2 Inspection and test of welds:

5.8.2.1 Visual inspection of welding must be conducted to ensure that the welding is performed in accordance with the welding procedure.

5.8.2.2 Nondestructive testing of weld must be performed by a trained technician. Interpretation of x-rays shall be made by a technician trained to a Level II.

5.8.2.3 The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 of API Standard 1104 “Welding of Pipelines & Related Facilities” (49CFR 195 currently referenced edition).

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents
1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
8.02 Operating Pressure Limits – Maintenance & Repair
9.06 Pipeline Welding
15.02 Visual Inspection and Non-destructive Testing

7. RECORDS

7.1 Complete “Maintenance and Surveillance Form”, (Form 3.01B) or equivalent may be used for documentation.

7.2 Submit as-built sketches to the (261) _______________ to update the drawings if pipe is replaced.

7.3 Maintain the records of each pipe repair for the useful life of the pipeline. Include at a minimum, the date, location, and description of each repair.

7.4 Maintain the records of each repair made to parts of the pipeline system other than pipe for at least 1 year. Include at a minimum, the date, location, and description of each repair.

TABLE 9.01-A

PIPELINE REPAIR - PIPE DAMAGE OR DEFECT

DAMAGE OR DEFECT	DISPOSITION OF CONDITION	
	Unpressurized	Pressurized
Dent on: (See Note 3)		
Welds	C	E, P
Body of pipe 12" (305 mm) or less nominal diameter: Depth greater than 1/4" (6.4 mm)	C	E, P
Body of pipe larger than 12" (305 mm) nominal diameter: 2% or more of nominal diameter	C	E, P
Groove, gouge or scratch with remaining wall thickness:		
Less than Design Wall Thickness	C	E, P
Welds:		
No Leak (See Note 1)	X	E, P
With Leak (See Note 2)	X	E, P
General Corrosion: (See Note 4)		
No Leak	C	C, M, E
Localized Corrosion Pitting:		
No Leak	C	E, C, M, P
With Leak (See Note 2)	C	L, E, P
All Other Leaks (See Note 2)	C	E, P

TABLE 9.01-A (Continued)

LEGEND

C Cutting out a cylindrical piece of pipe and replacing it with pretested pipe of similar or greater design strength.

E Full encirclement, welded split sleeve of appropriate design.

L Leak clamp.

M Establish new maximum operating pressure base on the actual remaining wall thickness.

P Plidco sleeve or equivalent (offshore or submerged).

X Cut out repair per applicable code and standard.

NOTES:

1. A weld on a pressurized pipeline segment may be repaired if:

   a. The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the specified minimum yield strength of the pipe; and

   b. Grinding of the defective area can be limited so that at least 1/8 inch (3.2 mm) thickness in the pipe weld remains.

2. Either the sleeve or the leak clamp are to be removed and replaced by a cylindrical piece as soon as it is feasible to take the piping out of service.

3. Each dent in steel pipe that operates at or more than 20% SMYS, must be removed unless the dent is repaired by a means that has been proven to restore permanent serviceability of the pipe.

4. Each transmission pipeline with general corrosion, and with a remaining wall thickness less than required for the exiting MOP, must be replaced or the MOP reduced based on the actual wall thickness. However, as stated in Note 3 above, the pipe can be repaired by a means that has been proven to restore permanent serviceability of the pipe.

NOT CURRENTLY IN USE

9.02
9.03
9.04

Primary Ref: 49 CFR 195.122, 195.422	Updated: Jan 2016

1. REFERENCE

49 CFR, Sections 195.122, 195.422(a), and API RP 2201 – Procedures for Welding and Hot Tapping on Equipment Containing Flammables

2. PURPOSE

To establish the requirements necessary for the installation of hot taps on pipelines under pressure.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (267) ______________ is responsible for hot tap installation and implementation of this procedure.

4. GENERAL

4.1 Mechanical fittings and material used to make a hot tap shall be designed for at least the Maximum Operating Pressure (MOP) of the pipeline.

4.2 This procedure outlines the items to be considered and the steps to be followed for the tapping of pipelines under pressure. This procedure should be used in conjunction with API 2201, "Procedure for Welding and Hot Tapping on Equipment Containing Flammables" (Latest Edition), and the API 2201 check sheet.

4.3 Each tap made on a pipeline under pressure shall be performed by a properly trained and qualified crew. See company OQ plan for details on qualification requirements.

4.4 All welding must be performed by a qualified welder in accordance with qualified welding procedures as required by "Pipeline Welding", Procedure 9.06 and company OQ plan.

4.5 Split tapping tees shall normally be used for branch connections. Saddles shall only be used if tapping tees cannot be obtained.

4.6 The term saddle shall include reinforcing saddles, wrap around saddles, or wrap around pipe, saddles, and proprietary fittings.

4.7 Split tapping tees and saddles shall be welded utilizing a qualified welder and welding procedure specifying low hydrogen welding rod.

5. PROCEDURE

5.1 Tap Location

5.1.1 The tap location must be at least 5 feet (1.5 meters) from a bend.

5.1.2 The area to be tapped shall not include a girth weld.

5.1.3 The outside diameter of the hot tap nipple, if possible, shall be a minimum of 2 inches (5 cm) from the longitudinal seam of the carrier pipe and shall be a minimum distance of 6 inches (15.2 cm) from a girth weld.

5.1.4 Hot taps are to be installed in a horizontal plane where possible.

5.2 Conditions of the Carrier Pipe

Prior to welding the hot tap nipple to the carrier pipe:

5.2.1 Visually inspect the outside diameter of the pipe for defects such as corrosion, mechanical damage, etc.

5.2.2 Check the wall thickness of the carrier pipe in the area where the nipple is to be attached, using the ultrasonic method.

5.2.3 Check for evidence of lamination.

5.3 Line Pressure

The line pressure during the process of welding the hot tap nipple to the carrier pipe should be lowered as much as the pipeline operations shall allow, and should not exceed the limits in Procedure 8.02, “Operating Pressure Limits-Maintenance & Repair”, Table 8.02A

5.4 Installation of Hot Tap Nipple and Valve

5.4.1 Specifications:

To provide added structural strength to the branch connection point, unless otherwise specified, pre-tested heavy wall thickness pipe shall be used for all hot tap nipples as follows:

5.4.1.1 For tap sizes 8” (20.3 cm) and above, 1/2” (1.27 cm) wall thickness minimum, a minimum of 35,000 psi specified minimum yield strength (SMYS) up to the SMYS of the carrier pipe, seamless, minimum length 8-1/2” (21.6 cm).

5.4.1.2 For tap sizes 6” (15.2 cm) and under, use schedule 80 wall thickness, minimum of 35,000 psi specified minimum yield strength (SMYS), seamless, minimum length 6-1/2” (16.5 cm). Thickness and SMYS of branch must be calculated and the values given above may need to be adjusted.

5.4.2 Preparation and Welding of Hot Tap Nipple

5.4.2.1 The hot tap nipple shall be fitted, beveled, and welded only by a qualified welder who has been authorized to weld hot taps after having passed Company’s qualification test.

5.4.2.2 The hot tap nipple shall be fitted and beveled to provide equal spacing around the circumference of the nipple.

5.4.2.3 The nipple is to be inspected to assure that the proper bevel is present and that the fit-up is adequate to provide complete penetration without burn through. Complete penetration of the root bead is necessary. Excessive penetration is undesirable due to interference with the cutter head of the tapping machine. An inside pass of the weld joining the nipple to the carrier pipe shall not be permitted.

5.4.2.4 Extreme care shall be exercised to maintain a true 90° angle between the axis of the hot tap nipple and the axis of the carrier pipe and to maintain a straight center line between the nipple and valve in order to maintain the proper position of the cutter head during the tapping operation.

5.4.2.5 All moisture and condensation shall be dried from the carrier pipe and the saddled end of the hot tap nipple by heating immediately before welding commences.

5.5 Testing and Inspection

5.5.1 Each hot tap fabrication shall be hydrostatically tested. Pretested pipe may be used.

5.5.2 Before making any welds on the saddle, a leak test of the fillet weld must be performed. Refer to Procedure #15.01, paragraph 10.6.

5.5.3 Radiographic inspection of butt welds is necessary. The fillet weld joining the hot tap nipple to the carrier pipe is to be examined visually and, at the discretion of the welding inspector, it can be inspected for surface defects utilizing the magnetic particle method.

5.6 Installation of Split Tapping Tee

5.6.1 Installation and Welding

5.6.1.1 The split tee shall be installed using a chain and jack or similar arrangement to insure a snug fit around the carrier pipe.

5.6.1.2 The longitudinal welds shall be made first. The welder(s) shall begin at the center of the saddle and work toward the ends. Each pass, including the stringer bead, shall be made for the entire length of the weld by each welder before successive passes are added. No connecting weld shall be made between the split tee and the carrier pipe along the longitudinal seam (use a backing piece, when possible).

5.6.1.3 Weld the ends of the split tee to the carrier pipe.

5.6.1.4 The extruded outlet of the split tee reinforcement shall be butt welded to the hot tap nipple or flange.

5.6.2 Completion of Hot Tap

5.6.2.1 The tapping machine shall be bolted to the flange of the valve. If a horizontal tap is being made, the tapping machine shall be supported so that no stress shall be placed on the hot tap nipple and valve. Extreme care is to be exercised in properly aligning and operating the tapping machine.

5.6.2.2 Each hot tap fabrication with the connected tapping machine shall be hydrostatically leak tested for a period of 30 minutes prior to cutting the hole. Pressure shall be limited to prevent overstressing the carrier pipe from external pressure and overpressuring the tapping machine.

5.6.2.3 The hole shall then be cut in the carrier pipe to complete the hot tap.

5.7 Installation of Full Encirclement Reinforcing Saddle

5.7.1 Preparation

5.7.1.1 The effectiveness of a full encirclement reinforcing saddle depends upon a snug fit around the carrier pipe. Maximum surface contact between the outside of the carrier pipe and the inside of the saddle is necessary prior to welding the two halves of the saddle together.

5.7.1.2 To accomplish the snug fit it might be necessary to grind a smooth groove inside the saddle to fit the longitudinal weld of the carrier pipe, if ERW pipe. The saddle thickness shall not be reduced to less than the thickness of the carrier pipe. The groove in the saddle must be such that the longitudinal carrier pipe weld shall not contact the bottom of the groove before the inside of the saddle contacts the outside of the carrier pipe.

5.7.2 Installation and Welding

5.7.2.1. The saddle shall be installed using a chain and jack or similar arrangement to insure a snug fit around the carrier pipe and the hot tap nipple.

5.7.2.2 The longitudinal welds shall be made first. The welder(s) shall begin at the center of the saddle and work toward the ends. Each pass, including the stringer bead, shall be made for the entire length of the weld by each welder before successive passes are added. No connecting weld shall be made between the reinforcement and the carrier pipe, (use a backing piece, when possible).

5.7.2.3 The extruded outlet of the reinforcement shall be fillet welded to the hot tap nipple.

5.7.2.4 Welding the ends of the reinforcing saddle to the carrier pipe is optional.

5.7.3 Completion of Hot Tap

5.7.3.1 The tapping machine shall be bolted to the flange of the valve. If a horizontal tap is being made, the tapping machine shall be supported so that no stress shall be placed on the hot tap nipple and valve. Extreme care is to be exercised in properly aligning and operating the tapping machine.

5.7.3.2 Each hot tap fabrication with the connected tapping machine shall be hydrostatically leak tested for a period of 30 minutes prior to cutting the hole. Pressure shall be limited to prevent overstressing the carrier pipe from external pressure and overpressuring the tapping machine.

5.7.3.3 The hole shall then be cut in the carrier pipe to complete the hot tap.

5.8 Coating of Assembly

Upon completion of the tap the entire assembly is to be thoroughly cleaned, primed, and coated with a coating that is compatible with the coating system on the carrier pipe. Special care should be taken to effectively seal the ends of the full encirclement saddle so that no moisture can penetrate and enter the area between the saddle and carrier pipe. This is extremely important since the ends of the saddle may not be welded to the carrier pipe.

5.9 Concrete Support

Horizontal tap installations shall be supported by concrete foundations extending back and under the line being tapped, placed on firm soil and installed as soon as possible after the side connection is welded in place.

6. SAFETY PROCEDURES DURING HOT TAPPING

The following safety procedures shall be followed during hot tapping

1) O&M #14.02 – Pipeline Isolation Lock and Tag
2) O&M #14.03 – Prevention of Accidental Ignition
3) Company Hot Work OSHA safety procedures
4) Other appropriate company safety procedures as shown on Hot Work permit

7. RELATED PROCEDURES

8.01 Maximum Operating Pressure
8.02 Operating Pressure Limits
14.02 Pipeline Isolation Lock and Tag
14.03 – Prevention of Accidental Ignition
Company Hot Work OSHA safety procedures

8. RECORDS

8.1 Submit as-built documentation to (268) ______________ for updating of drawings.

8.2 On buried pipeline, the "Pipeline Maintenance and Surveillance Report", (Form 3.01B) or equivalent may be used for documentation..

8.3 Keep above documents for the life of the pipeline.

PIPELINE WELDING
Hazardous Liquid Pipeline O&M Procedure #9.06

Primary Ref: 49 CFR 195.208-195.230	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.208, 195.214, 195.216, 195.222, 195.224, 195.226, 195.228, 195.230, 195.422(a), PHMSA alert notice March 24, 2010,
and
Section 6 of API-1104 (19th ed., 1999, including October 31, 2001 errata) or Section IX "Welding and Brazing Qualifications," of the ASME Boiler & Pressure Vessel Code (2004 ed., including addenda through July 1, 2005)

2. PURPOSE

The purpose of this procedure is to establish the requirements for qualifying welding procedure and welders for work on steel pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (274) _______________ is responsible to confirm that all pipeline welding is performed in accordance with this procedure.

The (275) _______________ is responsible for reviewing and approving all qualified welding procedures prior to start of production welding.

The (276) _______________ is responsible for retaining and maintaining a current record of approved welders, their identification numbers, and the procedures to which each welder is qualified.

4. GENERAL

4.1 All welding to be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements specified. The quality of the tests used to qualify the procedure shall be determined by destructive testing. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

4.2 A Welding Procedure Specification (WPS) is a written procedure prepared to provide direction for making production welds to specific requirements. It specifies the materials, consumables, and procedures to be used in making welds, either for a variety or for specific connection geometry, steel types and steel thickness.

4.3 The Procedure Qualification Record (PQR) documents the welding materials, consumables, and procedures defined by the WPS used to weld a test coupon. It also contains the test results of the tested specimens. The PQR basically

establishes that the weldments specified by the WPS are capable of providing the required properties for its intended application.

4.4 The Welder Performance Qualification (WPQ) documents the ability of the welder being tested to produce a weld using a specific set of materials, consumables, and procedures to meet certain quality requirements.

4.5 Supports or braces may not be welded directly to pipe that shall be operated at a pressure of more than 100 PSIG.

4.6 A weld map and weld location record shall be completed.

4.7 All visual inspection and nondestructive testing shall be per Procedure 15.02.

4.8 The ground wire may not be welded to the pipe or fitting being welded.

5. <u>QUALIFICATION OF WELDING PROCEDURES AND WELDERS</u>

5.1 Welding procedures must be qualified by destructive testing. All welding performed on hazardous liquid pipeline systems shall be completed using welding procedures qualified in accordance with the API Standard 1104 “Welding of Pipelines and Related Facilities” or Section IX “Welding and Brazing Qualifications” of the ASME Boiler and Pressure Vessel Code (49CFR 195.3 currently referenced edition which is (20th edition, October 2005, errata/addendum [July 2007], and errata 2 [December 2008]).

5.2 Each welder shall be qualified in accordance with section 6 of API Standard 1104 (19th edition 1999, including errata October 31, 2001; and 20th edition October 2005, including errata/addendum (July 2007) and errata 2 December (2008). or Section IX “Welding and Brazing Qualifications” of the ASME Boiler and Pressure Vessel Code (ibr, 49 CFR192.7 currently referenced editions).

5.2.1 No welder may weld with a particular welding process unless, within the preceding six calendar months, the welder has;

- Engaged in welding with that process, and
- Had one weld tested and found acceptable under Section 9 of API 1104 (49 CFR 195 currently referenced edition which is (20th edition,

October 2005, errata/addendum [July 2007], and errata 2 [December 2008]).

5.2.2 When there is specific reason to question the welder's ability to make welds that meet the specification, the WPQ qualification which supports the welding he is doing shall be retested. All other qualifications not questioned remain in effect.

5.3 The company shall normally not have its own qualified welders. In this case, each contractor is responsible for the welding performed by their organization. They shall conduct the tests required to qualify their welding procedures and each of their welders.

5.4 The company shall normally not have its own qualified welders. In this case it is the contractor's responsibility to furnish the Company with complete copies of their welding procedure specification (WPS), procedure qualification record (PQR), and welding performance qualifications record (WPQ) for each welder, and any changes that occur thereto while working for the Company. The contractor is also responsible for retaining and maintaining complete documentation of same, and providing full access to Company as required.

6. PROCEDURE

6.1 Prior to the start of any welding, an appropriate weld procedure shall be selected and qualified, if not presently qualified.

6.2 Each welder must be qualified to weld by the selected procedure.

6.3 All production welding must conform to the requirements of design drawings or specifications, the selected qualified welding procedure specification (WPS), and within the limits of the welder's performance qualification (WPQ).

6.4 The welding operation must be protected from the weather conditions that would impair the quality of the completed weld.

6.5 Before beginning any welding,

6.5.1 The welding to be performed shall be evaluated for hazards which may affect the safety and health of personnel working in the area or the general public. Welding shall begin only when safe conditions are indicated.

6.5.1.1 A thorough check shall be made in or around a structure or area containing gas facilities to determine the possible presence of a combustible mixture.

6.5.1.2 Where welding is performed in a public area, a means to shield the public from welding arcs shall be provided between welding and public, or assure that public is not present during welding.

6.5.2 Welding surfaces must be free of defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.5.3 Welding surfaces must be clean and free of any material that may be detrimental to the weld. Each joint of pipe may require swabbing to remove all dirt and foreign materials from the inside.

6.5.4 Bevels shall be checked for proper dimensions and angle.

6.5.5 Ensure that the longitudinal seams are offset. The seams should be located on the upper quadrant of the line and preferably within 30° of top center. Alternate joints shall be rotated to right or left at least 15° to avoid aligning the seams in adjacent joints. Exceptions to this requirement shall be made for making bends, as the longitudinal seam must remain on the neutral axis of the bend, and at other locations as may be indicated on the design drawings.

6.5.6 The line-up shall be checked to ensure proper root spacing and alignment. This alignment must be preserved while the root bead is being deposited.

6.5.7 Welding consumables shall be confirmed for correct type, proper use, control and handling prior to and during use. All welding rod stubs and discarded rods shall be gathered and disposed of in a manner and place authorized by the Company. No welding rod shall be left on or around the working area or deposited in the ditch.

6.6 Preheated and interpass temperatures shall be maintained within the specified ranges.

6.6.1 Preheating shall be required when the welding procedure indicates that chemical composition, ambient and/or metal temperature, material thickness, or weld-end geometry require such treatment to produce satisfactory welds.

6.6.2 The temperature shall be checked by the use of temperature-indicating crayons, thermocouple pyrometers, or other suitable methods to assure that the required preheat temperature is obtained prior to and maintained during the welding operation.

6.7 Grinding and cleaning of the stringer (root) bead shall be completed prior to depositing subsequent filler passes.

6.8 Welds in carbon steels having high carbon content which require stress relieving by the applicable code (API 1104, 49 CFR 195 currently referenced edition which is (20th edition, October 2005, errata/addendum [July 2007], and errata 2 [December 2008])., shall be stress relieved as prescribed in ASME Boiler and Pressure Vessel Code, Section VIII. Stress relieving may also be advisable for welds in steel having lower carbon or carbon equivalent when adverse conditions exist which cool the weld too rapidly.

6.8.1 Welds in carbon steels shall be stress relieved when the wall thickness exceeds 1-1/4 in (3.81 cm).

Note: Above mentioned codes shall be the 49CFR 195 currently referenced editions.

6.9 Mark and ensure that all arc burns are removed and repaired. A ground may not be welded to the pipe or fitting that is being welded.

6.10 A miter joint is not permitted (not including defections up to 3° that are caused by misalignment). Any weld which is not at right angles to the axis of the pipe shall be considered a mitered weld, unless the angle is specifically called for on the design drawings.

6.11 Weld numbers and welder identification numbers shall be applied using waterproof crayon, paint pens, or similar markers on the pipe coating adjacent to the weld for temporary identification. Marks shall be made on the top of the pipe approximately 1 foot (0.30 meters) from the cutbacks on the pipe coating, and shall be visible after joint coating is complete.

6.12 Each welding procedure must be recorded in detail including results of qualifying tests. A permanent record in the form of weld maps shall be made indicating the location of all welds that can be cross referenced to the weld's nondestructive testing and to the welder making the weld. Also, a record of the total number of girth welds and the number nondestructively tested, including the number of rejected and the disposition of each rejected weld shall be maintained.

6.13 In large diameter pipe (greater than 20"), the company must give considerate to girth weld bevels being properly transitioned and aligned. More specifically, girth weld pipe ends must meet API5L end diameter and diameter out-of-roundness specifications and API #1104 alignment and allowable "high-low" criteria. [PHMSA alert notice March 24, 2010]

7. REPAIR OR REMOVAL OF WELD DEFECTS

7.1 Qualified procedures and currently qualified welders are required for all repair work.

7.2 Each weld that is found unacceptable must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be completely removed if it has a crack that is more than 8 percent of the weld length.

7.3 Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

7.4 The repair of a crack in a weld, providing it does not exceed 8% of the weld length, or, of any defect or flaw in a previously repaired weld, must be according to a written weld procedure qualified under Section 5.0 of this procedure "Qualification of welding procedures and welders". The welder(s) must have qualified to the repair procedures prior to affecting the repair.

The repair procedure must provide that the repaired defect(s) equal or exceed the original mechanical properties of the originally intended weld.

Re-repair of welds shall not be permitted unless approved by the District Engineer.

After any repair or re-repair, the weld must be non-destructively tested by any process to determine and ensure the repair's integrity. Please refer to Procedures 15.02 "Visual Inspection and Nondestructive Testing".

7.5 An arc burn can be caused by any means, whether by welding or other, can be injurious to the carrier pipe and is totally unacceptable. Arc burn affects the integrity of the pipe and can cause mechanical deficiencies and possible stress concentrations. Verify removal of arc burn (metallurgical notch) by non destructive testing (ammoniom per sulfate).

An arc burn can be completely removed by grinding. However, the grinding process must not be excessive and to the point where the wall thickness is less than the minimum thickness required by the tolerances in the original specification of the pipe.

If the arc burn cannot be completely removed by grinding, a cylinder of the pipe containing the defect must be removed.

If grinding provides a thinner pipe wall than originally manufactured, and the pipe is to be retained, de-rating of the pipe must be considered.

8. RELATED PROCEDURES

9.01 Pipeline Repair Procedures
14.03 Prevention of Accidental Ignition
15.02 Visual Inspection and Nondestructive Testing

9. RECORDS

9.1 Keep copies of the welding procedures used, welding procedures qualifications, the location of the welds, the welders used, and the results of all nondestructive testing in the pipeline historical file.

9.2 Keep copies of pipe and fitting material qualifications, as-built drawings, and hydrostatic test records in the pipeline historical file.

9.3 These records are to be retained for the life of the facility.

Not currently in use	Updated: Jan 2016

<u>NOT CURRENTLY IN USE</u>

Section 10

Not currently in use	Updated: Jan 2016

NOT CURRENTLY IN USE

Section 11

PIPELINE UPRATING
Hazardous Liquid Pipeline O&M Procedure #12.01

Primary Ref: 49 CFR 195.406	Updated: Jan 2016

1. REFERENCE

   49 CFR 195.406.

2. PURPOSE

   To outline the minimum requirements for increasing the maximum operating pressure (MOP) in pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (282) _______________ is responsible for the implementation of pipeline uprates, including determination of the new MOP, as well as providing a specific written procedure for uprating each pipeline.

   The (283) _______________ is responsible for the operation of the pipeline once the upgrade is finished.

4. GENERAL

   The (284) _______________ shall provide detailed written procedures for uprating pipelines and associated facilities. This written procedure shall address:

   4.1 Review of the design, operating, and maintenance history of previous testing of the pipeline.

   4.2 All necessary tests associated with the pressure uprate. (Pressure testing shall normally be required.)

   4.3 The new (higher) MOP and a safe rate of incremental pressure increases (i.e., appropriate valve settings).

   4.4 The frequency and method of leak testing, including criteria defining a "potentially hazardous leak," between incremental pressure increases.

   4.5 Full compliance of Federal and State Regulations.

5. PROCEDURE

5.1 Determine new MOP. Refer to Procedure 8.01.

5.2 Pressure test the section to 125% of new MOP. (Refer to Procedure 15.01 for details.)

6. RELATED PROCEDURES

8.01 Maximum Operating Pressure
8.02 Operating Pressure Limits – Maintenance & Repair
9.01 Repair Procedures
15.01 Pressure Testing

7. RECORDS

Record each investigation required by this procedure, all work performed, and all pressure tests conducted in conjunction with the pressure uprate. Maintain records of the latest test as long as the facility tested is in use.

CONVERSION OF SERVICE (STEP BY STEP)
Hazardous Liquid Pipeline O&M Procedure #12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
1.	Conduct historical records study by reviewing design, construction, operation, and maintenance history of the pipeline. Use form #12.02A and form #12.02B (pipeline fact sheet template) or equivalent to document this review. Target Date for Completion:				
2.	Make determination if sufficient historical records are not available, and then appropriate tests must be conducted to determine if the pipeline is safe to operate. (Select all that apply) ○ Corrosion surveys including one or more of the processes used in the integrity management program: ○ External Corrosion Direct Assessment (ECDA) evaluations. These normally include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM) ○ In line inspection (ILI) tools ○ Guided wave ○ Ultrasonic inspections for corrosion and wall thickness determinations ○ Positive material identification inspection				

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
	using portable XRF analyzers ○ Acoustic emissions inspection ○ Tensile tests ○ Internals inspections in accordance with O&M procedure #6.02 ○ Radiographic inspections Target Date for Completion:				
3.	<u>Review tests results</u> from item selected in step #2. Document review and any new action items. Target Date for Completion:				

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
4.	Visually inspect the pipeline right-of-way, all aboveground segments, and appropriate underground segments of the pipeline for physical defects or other conditions which could impair the strength or tightness of the line. Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites: ○ Corrosion surveys ○ Segments with coating damage or deterioration due to soil stresses and/or internal or external temperature extremes ○ Pipeline component locations ○ Locations subject to mechanical damage ○ Foreign pipeline crossings ○ Locations subject to damage due to chemicals such as acid ○ Population density Document inspection and any new action items. Target Date for Completion:				

CONVERSION OF SERVICE (STEP BY STEP)
Hazardous Liquid Pipeline O&M Procedure #12.02

Step #:	**Description:**	**Who Respon:**	**Status:** (not started, pending, complete)	**Date Completed:**	**Comments and Action Taken to Verify Compliance:**
5.	Correct any defects or conditions discovered during reviews and/or inspections prior to line commissioning. Document all remedial action and any new action items. This includes but is not limited to; coating damage, pipeline repairs of internal/external corrosion, etc. Target Date for Completion:				
6.	Determine new MOP for the line in accordance with 192.619 and Procedure 8.01. Document new MOP and any new action items Target Date for Completion:				

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
7.	Conduct a pressure test the line to substantiate the new line MOP in accordance with 192 subpart J and procedure #15.01. Schedule CSFM certified pressure testing company to conduct pressure test. See attached list of CSFM certified pressure testing companies obtained from CSFM website. Make repairs discovered during the hydro test using O&M procedure #9.01. Document pressure test and any new action items. Target Date for Completion:				
8.	Conduct high consequence area (HCA) survey in accordance with 192.5 and compare the proposed MOP and operating stress levels with those allowed for the location class. Replace pipe and/or facilities to make sure the operating stress levels is commensurate the location class. Target Date for Completion:				

CONVERSION OF SERVICE (STEP BY STEP)
Hazardous Liquid Pipeline O&M Procedure #12.02

Step #:	Description:	Who Respon:	Status: (not started, pending, complete)	Date Completed:	Comments and Action Taken to Verify Compliance:
9.	Within one year of the date that the converted line is placed in gas service, provide cathodic protection as required by 192.455. Document design and installation of CP system and any new action items. Target Date for Completion:				
10.	Include the pipeline in the next PHMSA annual report. Target Date for Completion:				
11.	If the converted pipeline is transmission, submit to the National Pipeline Mapping System (NPMS). Target Date for Completion:				
12	Develop pipeline specific O&M (PSOM) for this new pipeline. Document PSOM date and any new action items. Target Date for Completion:				

Compliance Mgr Signature and Date: ______________________ ________

Signature Date

Operations Mgr Signature and Date: ______________________ ________

Signature Date

PIPELINE MOVEMENT
Hazardous Liquid Pipeline O&M Procedure #12.03

Primary Ref: 49 CFR 195.424	Updated: Jan 2016

1. REFERENCE

   49 CFR, Section 195.424.

2. PURPOSE

   The purpose of this procedure is to establish procedures for the movement of in-service line pipe.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (296) _______________ is responsible for the implementation of this procedure when it is necessary to move line pipe.

4. GENERAL

   4.1 No pipeline may be moved unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure (MOP).

   4.2 No pipeline containing highly volatile liquids (HVL), where materials in the line section involved are joined by welding, may be moved unless:

   4.2.1 Movement when the pipeline does not contain highly volatile liquids is impractical.

   4.2.2 Precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline must be taken.

   4.2.3 The pressure in that line section is reduced to the lower of the following:

   a) Fifty percent or less of the maximum operating pressure; or

   b) The lowest practical level that shall maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 psig (345 kPa) above the vapor pressure of the commodity.

   4.3 No pipeline containing highly volatile liquids, where materials in the line section involved are not joined by welding, may be moved unless:

4.3.1 Paragraphs 4.2.1 and 4.2.2 of this section are complied with, and

4.3.2 That the line section is isolated to prevent the flow of highly volatile liquid.

5. PROCEDURE

The (297) ______________ shall provide a segment specific procedure for each pipeline movement job which shall address:

5.1 Coordination and planning of excavation, line shutdown, and/or pressure reduction, including acquisition of any necessary permits.

5.2 Specification of an acceptable new pipeline profile which does not overstress the pipeline at any point.

5.3 Careful movement of the pipe which shall not overstress the pipe, damage the coating, or cause a leak.

5.4 Excavation and backfill requirements.

5.5 Inspection of pipe before, during, and after the move for damaged coating, evidence of corrosion, or other indication of damage.

5.6 Remedies of any pre-existing corrosion condition or damage revealed during the line movement operation.

5.7 Inspection of the slings that shall be used to move the line. If a sling breaks, someone could get hurt.

5.8 Ensuring that only one person is designated to give signals to the crane operators.

5.9 Ensuring that personnel are not in the trench when the pipe is being moved.

5.10 Provision of an adequate communications system having at least one radio-equipped vehicle located out of harm's way, to be ready for emergency communications.

5.11 Safety personnel as a top priority.

5.12 One-Call Systems and any other agencies having substructures in the area are notified prior to any excavation.

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents
1.02 Reporting of Safety Related Conditions
3.01 Damage Prevention Program

7. RECORDS

The "Pipeline Maintenance and Surveillance", Form (Form 3.01B) or equivalent form may be used for documentation. Maintain all other records normally required for new pipeline construction. Maintain all records for the life of the system.

ABADONMENT OR INACTIVATION OF FACILITIES
Hazardous Liquid Pipeline O&M Procedure #13.01

Primary Ref: 49 CFR 195.402(c)(10)	Updated: Jan 2016

1. REFERENCE

   49 CFR, Sections 195.2, 195.59, 195.402(c)(10), and CSFM Information Letter #97-001 (dated August 2009)

2. PURPOSE

   The purpose of this procedure is to establish minimum requirements for the abandonment of hazardous liquid pipeline facilities and for providing the pipeline operator with procedures that must be followed when requesting a change in a pipeline's operational status with the California State Fire Marshall (CSFM).

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (303) _______________ is responsible for determination, evaluation, and taking proper action to comply with this procedure for abandonment of pipeline facilities.

4. DEFINITIONS

   4.1 An active pipeline means a pipeline or pipeline segment which is in service whether or not the pipeline is fully operational. This includes pipelines which may have been utilized to transport hazardous liquids but are currently static or unused. This pipeline category includes any pipeline or pipeline segment which has not been formally approved in writing as OUT-OF-SERVICE or ABANDONED by CSFM. These pipelines must comply with all provisions of California Government code Chapter #5.5 and US DOT 49 CFR Part 195 regulations. Each active pipeline segment (whether in use or not) is to be reported to CSFM as active on the annual CSFM operator questionnaire and shall be subject to annual pipeline user fees.

   4.2 An out-of-service pipeline means a pipeline or pipeline segment which has been effectively cleaned of all hazardous liquids, filled with water or inert gas and blinded or otherwise isolated from an active pipeline system. Once the process has been verified and accepted in writing by CSFM, this category of pipeline becomes non-jurisdictional and CSFM shall no longer enforce 49 CFR 195 regulations.

   CSFM shall still maintain basic data on out-of-service pipelines and request that the pipelines be reported on the CSFM annual operator questionnaire. They shall not be assessed user fees. Should an operator wish to return this pipeline to service, they must show the basic federal maintenance and inspection activities were performed (e.g., IMP cathodic protection, ROW patrols, USA notifications, etc.) or otherwise prove the integrity of the pipeline

4.3 An abandoned pipeline means a pipeline or pipeline segment which has met the criteria of an out-of-service pipeline (purged, sealed, and disconnected from an operating system) but shall not have basic federal maintenance and inspection activities performed. An abandoned pipeline normally cannot be returned to hazardous liquid service unless the “return to service” procedure shown below is followed.

CSFM annual fees are not applicable for abandoned pipelines. In addition, abandoned pipelines do not have to be reported to CSFM or PHSMA on the annual reports. However, CSFM shall maintain data on the abandoned pipelines.

5. RETURNING PIPELINE TO SERVICE

5.1 Before a pipeline can be re-classified from out-of-service to active, the operator must submit to the CSFM, and the CSFM must approve, a written plan describing the process to be used to demonstrate the integrity of the pipeline. An inspection of the pipeline and pipeline records shall be conducted by CSFM to determine compliance with state and federal pipeline regulations. Pipelines that have been returned to active status are to be reported as active on the annual CSFM operator questions and PHMSA annual report. Mileage fees shall then be assessed to the pipeline operator.

6. GENERAL

6.1 Facilities to be abandoned shall be evaluated and handled on an individual basis.

6.2 All applicable federal (MMS, Corps of Engineers, BLM), state, county, and local regulations or ordinances shall be complied with in the abandonment of hazardous liquid facilities.

6.3 Physically remove all abandoned facilities, if practical. If this is not feasible, sever below grade and remove all aboveground piping and equipment.

6.4 Pipeline facilities abandoned in place shall not be maintained and should not be considered for reactivation for service at a later date.

7. PROCEDURE – ABANDONMENT (Permanently Removed From Service)

7.1 Facilities to be abandoned shall be disconnected and isolated from all sources and supplies of hazardous liquid such as other pipelines, crossover piping, meter stations, control lines, and other appurtenances by a physical separation.

7.2 Open ends of pipelines shall be sealed by a welded plate or a permanent type closure or fitting. Branch connections or taps on the facility shall be plugged or sealed.

7.3 Pipeline segments shall be pigged when applicable, as part of line dewatering or purging with inert gas to ensure that no liquid hydrocarbons remain in the line.

A job specific purging procedure shall be developed before the work begins. Refer to CSFM information bulletin on abandonment and/or ASME B31.4 section 457, as a guide in development of job specific purging procedures.

7.4 The (304) ______________ shall review local abandonment procedures and permitting requirements prior to the start of work.

7.5 Abandoned facilities shall be purged of hazardous liquid. If air is used as a purging medium, precautions shall be taken to ensure that a combustible mixture is not present after purging and that the mixture cannot ignite during purging.

7.6 Abandoned pipelines may be filled with air, inert gas, inhibited water, Bentonite Clay (drilling mud), sand slurry, lean cement slurry or other inert materials.

7.7 Where possible, pipeline vaults should be filled with compacted inert material. Acceptable backfill material includes but is not limited to native material, sand slurry and lean cement slurry.

7.8 For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crossed over, under, or through a commercially navigable waterway, the last operator of that facility must file a report when that facility is abandoned.

For pipelines abandoned after October 10, 2000, notification and data submittal about the abandoned facility is to be to the National Pipeline Mapping System (NPMS). Submission shall be in accordance with the NPMS “Standards for Pipeline & Liquefied natural Gas Operator Submissions”.

Other submission alternatives exist.

Data on pipelines abandoned prior to October 10, 2000 must be filed by April 10, 2001.

Please refer to 49CFR 195.59 for additional information on submission.

8. PROCEDURE - INACTIVATION

8.1 Protect inactive facilities, as they were protected before inactivation, from corrosion by using cathodic protection or other means to prevent deterioration. Generally, onshore pipelines should remain filled with inert gas and be pressurized above atmospheric pressure. Offshore pipelines should be filled with a non-hazardous liquid to maintain negative buoyancy.

8.2 Inactive facilities must be treated the same as active facilities and all requirements of the Standard Operating and Maintenance Procedure Manual for Hazardous Liquid Pipelines must be carried out on inactive facilities.

8.3 Inactive, unmaintained facilities may be returned to service after a thorough engineering review, testing, and conversion to service.

9. RELATED PROCEDURES

12.02 Conversion of Service

10. RECORDS

10.1 The "Pipeline Abandonment Record", (Form 13.01A) or equivalent may be used for documentation. A copy of this form shall be sent to the (305) _______________ and placed in the system historical file.

10.2 Update drawings with abandonment or removals. Pipelines that have been removed or abandoned in-place and sold shall be eliminated from the drawings. Other in-place abandonments need to be indicated on drawings as being abandoned in-place.

10.3 Retain the original of the form in a permanent District Office abandonment file for future reference.

10.4 The abandonment of a hazardous liquid transmission and/or gathering pipeline facility requires the updating and submittal of a shape files, meta data files, and contact info files to the National Pipeline Mapping System (NPMS). Please refer to liquid O&M procedure #1.06.

VALVE SECURITY
Hazardous Liquid Pipeline O&M Procedure #14.01

Primary Ref: 49 CFR 195.428	Updated: Jan 2016

1. REFERENCE

49 CFR, sections 195.420(c) and 195.436.

2. PURPOSE

The purpose of this procedure is to outline the requirements for securing or locking valves to prevent accidental, inadvertent operation, and protection from tampering.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (311) _______________ is responsible for providing security devices to prevent unauthorized operation of the valves.

4. GENERAL

4.1 All valves necessary for the safe operation of the pipeline system shall be secured. Affected valves to be determined by (312) _______________.

4.2 All power operated valves at unattended locations shall have the control boxes locked to prevent manual operation.

4.3 Other valves at attended or restricted locations which require security may be locked or secured as determined by the (313) _______________.

4.4 Each emergency valve in an exposed facility shall protected from vandalism and unauthorized entry and unauthorized operation.

5. PROCEDURE

5.1 The (314) _______________ shall determine which valves require security devices to prevent unauthorized operation.

5.2 Each valve must be protected from unauthorized operation and from vandalism. The company shall use one or more of the following security techniques to prevent unauthorized operation and vandalism.

- Location inside a locked building, enclosure, or security fencing
- Locks on equipment
- Removal of valve handles or hand wheels

- Other options may be used if reviewed and documented and described in the PSOM

5.3 Valves which are normally secured in the open position include:

5.3.1 Mainline valves.

5.3.2 Branch line block and bleed valves.

5.3.3 Delivery station isolation valves.

5.3.4 Isolation valves under relief valves.

5.4 Valves which are normally secured in the closed position include:

5.4.1 Valve isolating systems having different maximum allowable operating pressures.

5.4.2 One valve in each bypass line around a station.

5.5 Vandalism history shall be evaluated during the continuing surveillance reviews and may dictate which security method is prudent. The protection from vandalism provided at each valve inspected should be adequate to prevent the level of vandalism experienced at the site.

Valves that may be exposed to outside force damage such as vehicular damage should have some type of protection surrounding them. Typically this would be bollards.

6. RELATED PROCEDURES

7.01 Valve Maintenance
14.02 Pipeline Isolation - Lock and Tag

7. RECORDS

Use form #7.01A or equivalent to document proper valve security. Maintain the record for five (5) years.

Primary Ref: 49 CFR 195.420, 195.436	**Updated: Jan 2016**

1. REFERENCE

49 CFR, Sections 195.420(c) and 195.436.

2. PURPOSE

The purpose of this procedure is to establish a procedure to be used during isolation of pipeline facilities for maintenance or modification and to protect people and machinery against unauthorized operation of equipment, valves, or electrical switches while work is performed on facility equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (320) _______________ must use his best judgment in deciding the extent of blinding and purging of the pipeline section with an inert gas necessary to safely complete the maintenance work.

4. GENERAL

4.1 Prior to commencement of work, checks need to be conducted by supervisors to assure procedure compliance by personnel, that adequate instruction for their portion of the work exists, and adequate communications between the various sections of the overall work site is in place.

4.2 Locks and tags shall be used to prevent inadvertent operation of valves, controlling devices, circuit breakers, electrical switches, electrically driven equipment, or other equipment while maintenance or construction is performed on facilities.

4.3 Include actions to insure safe ditching conditions, backfill disposal, and sufficient fire extinguishers.

5. PROCEDURE

5.1 Piping and Equipment Isolation

5.1.1 Identify all valves, lines, electrical switches, and equipment controlling devices, which must be de-energized, de-pressured, drained, or isolated before maintenance work can safely begin.

5.1.2 Isolate all piping and equipment associated with the maintenance or construction activities to be performed.

5.1.3 Remove all hydrocarbon gas or volatile liquids within the work area by draining or venting to atmosphere.

5.2 Lock and Tag

5.2.1 Safety locks and "Danger – DO NOT OPERATE" tags shall be used where applicable to prevent inadvertent operation of those devices that pose a hazard, if operated while performing maintenance or construction activities.

5.2.2 Complete a "Danger - DO NOT OPERATE" tag showing the date, time, reason for tagging, and name of person performing the lockout. Secure this lock and tag to the equipment to preclude unauthorized operation.

5.3 Verifications and Checking

5.3.1 Verify that the equipment is:

5.3.1.1 Shut down

5.3.1.2 De-energized

5.3.1.3 De-pressured and drained

5.3.1.4 Isolated from all process or utility lines

5.3.2 After isolation and venting, conduct a check for leakage. If leakage occurs and cannot be controlled by adjustments and/or grease sealing, the use of skillets, blind flanges, or other suitable means shall be employed to prevent gas and/or volatile liquids from entering the isolated section.

5.3.3 Ensure that the work area remains properly ventilated throughout the course of work. If applicable, use a combustible gas indicator to verify that adequate ventilation is maintained before and during the maintenance period.

5.4 Restoring Isolated Sections to Service

5.4.1 Purge isolated sections of piping and related equipment before placing in service. Give consideration to the purge gas and venting locations to assure that all possible air entrapments are removed and to insure that no combustible mixtures reside within the piping and/or equipment at the completion of the purge period.

Refer to Procedure 9.03 "Purging Pipelines" in the Gas Pipeline O&M for complete purging procedures.

5.4.2 After the purge is completed and vents are closed, a low pressure hold may be used to allow for leak checks. Upon full pressurization, conduct a final leak check.

5.4.3 After all related operating checks are completed and pertinent piping and/or equipment are ready to be placed in service, remove the locks and tags. Removal of the lock and tag must be by the person who placed them originally.

6. RELATED PROCEDURES

14.03 Prevention of Accidental Ignition
Company Lockout/Tagout Procedure

7. RECORDS

None required by this procedure and PHMSA regulations. Maintain copy of "Lockout/Tagout" log as required by company OSHA policy.

PREVENTION OF ACCIDENTAL IGNITION
Hazardous Liquid Pipeline O&M Procedure #14.03

Primary Ref: 49 CFR 195.402, 195.405, 195.438 **Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.402, 195.405 and 195.438.

2. PURPOSE

   To establish safety practices to minimize the danger of accidental ignition of combustible flammable hydrocarbon liquid mixtures in the areas where the presence of flammable hydrocarbon vapors constitute a hazard of fire or explosion.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (326) ______________ is responsible for implementation of this procedure, which shall be followed closely to minimize the possibility of accidental ignition and shall be carried out on a continual basis with highest priority.

4. GENERAL

   4.1 Continually implement and monitor this procedure to insure safe operations.

   4.2 Permit only the required personnel, vehicles and work equipment in the hazardous work area.

   4.3 Prohibit smoking materials within the hazardous areas.

   4.4 Exercise precautions during cutting, welding, and grinding on pipelines which could possibly contain an explosive gas-air mixture or distillates.

   4.5 Exercise precautions during pigging operations, handling of flammable liquids, and when using or working with internal combustion equipment (welding machines, etc.) in the vicinity of hazardous areas.

   4.6 Do not install or remove electrical isolation devices, such as insulating flange kits, in vaults or other areas subject to the accumulation of explosive gas-air mixtures.

   4.7 Protection against ignition arising out of static electricity, lightning, and stray currents during operation and maintenance activities, must be afforded to aboveground breakout tanks involving floating roofs.

   For specific recommendations and practices, refer to 49CFR 195.405(a).

5. PROCEDURE

5.1 Smoking, open flames and other sources of ignition are prohibited around and near pump station areas, breakout tank areas, enclosures and other areas where the possible leakage or presence of flammable/combustible liquids/vapors present a hazard of fire or explosion.

5.2 Post “No Smoking” signs to serve as warning in hazardous areas.

5.3 During construction and maintenance of facilities, post temporary “No Smoking” signs in the applicable areas. Advise construction employees they shall be expected to comply with these signs.

5.4 Prohibit smoking in any area where a combustible mixture might be present.

5.5 Locate and nullify all possible sources of ignition in an area before a hazardous amount of hydrocarbon vapor is vented to the atmosphere. Prior to venting, review the potential hazards involved when blowing down or purging facilities in congested areas, streets, highways, subdivisions, plants, and around electrical transmission lines.

5.6 Do not use open flame devices such as heaters and lanterns in hazardous areas.

5.7 Use explosion-proof, approved for Division I, Group D locations, flashlights, lighting fixtures, extension cords, and other electrical devices in hazardous areas. Maintain these devices in good working condition.

5.8 Fire extinguishers shall be manned and ready for use at all times during the cutting and welding operations.

5.9 Make a thorough check with a combustible gas indicator prior to welding in or around a structure or area containing hazardous liquid facilities to determine the possible presence of a combustible mixture. If safe conditions are indicated, welding and/or cutting may begin.

5.10 Make efforts to minimize the mixing of air with hydrocarbon vapor when welding or cutting on or around hazardous liquid piping.

5.11 When cutting or rejoining pipelines, use a jumper connecting to both line sections to prevent arcing caused by cathodic protection or induced currents. If possible, shutdown cathodic protection (CP) rectifier(s) during performance of work.

5.12 Temporarily seal any openings in piping or hazardous liquid containing facilities in the area, if required.

5.13 Do not weld or cut on pipe or pipe components that contain a known combustible mixture of hydrocarbon vapor and air.

5.14 Store flammable or combustible materials a minimum of 20 feet (6 meters) from any pump shelter or building.

5.15 Tanks storing liquid hydrocarbons shall be spaced and protected with fire extinguishing devices per NFPA 30 (49CFR 195 currently referenced edition).

5.16 Train appropriate personnel to properly use firefighting equipment. Simulated emergency conditions shall be used unless a valid reason exists not to.

6. RELATED PROCEDURES

14.02 Pipeline Isolation - Lock and Tag
Company “Hot Work” safety procedures

7. RECORDS

Hot work permits or equivalent records shall be maintained for minimum of five years.

EXCAVATIONS
Hazardous Liquid Pipeline O&M Procedure #14.04

Primary Ref: 49 CFR 195.402, 195.422	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Section 195.402 (c) (14), 195.422 (a), and OSHA 29 CFR 1926.651

2. PURPOSE

   The purpose of this procedure is to establish safety requirements for protection of personnel who enter excavations such as narrow trenches for pipeline maintenance activities.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (332) _______________ is responsible for implementation and compliance with this procedure.

4. GENERAL

   For personnel safety, plan all excavations in advance, giving consideration to such items as underground installations, soil stability, weather conditions, and other construction activities.

5. PROCEDURE

   5.1 Preparation for Excavations

   5.1.1 Notify other operating companies affected and request them to locate their underground structures. Utilize a One Call System. (See Procedure 3.01)

   5.1.2 Notify all affected landowners.

   5.1.3 Remove or stabilize trees, boulders, and other surface encumbrances that create a hazard, when feasible.

   5.2 Protection of Personnel from Ground Movement. Refer to company safety procedures for details.

   5.2.1 Protect personnel from ground movement in any excavation using a support system or sloping.

5.2.2 Use slope or support system for:

5.2.2.1 Banks 5 feet (1.5 meter) high or greater.

5.2.2.2 Trenches less than 5 feet (1.5 meters) deep if hazardous ground movement may be expected.

5.2.2.3 Trenches 5 feet (1.5 meters) deep or more.

5.2.3 Use support system for trenches 5 feet (1.5 meters) or more deep and 8 feet (2.4 meters) or more long. In lieu of support system, use sloping above the 5 foot (1.5 meters) level at a rise not steeper than 1 foot (0.30 meters) rise per 1/2 foot (0.15 meters) horizontal.

5.2.4 Trench shields or boxes may be used in lieu of shoring or sloping.

5.2.5 Provide a means of exit, such as ramps, ladders, or steps located so the maximum travel distance is 25 feet (7.6 meters) when employees must work in trenches 4 feet (1.2 meters) deep or more.

5.2.6 Move bracing or shoring along with the excavation.

5.2.7 Remove trench supports from the bottom as backfilling operations progress. Release trench jacks slowly in unstable soil. Use ropes to remove them after personnel have cleared the trench.

5.3 Precautions for All Excavations

5.3.1 Inspect excavations at least daily and after every rainstorm or other hazard-increasing occurrence.

5.3.2 Do not allow hazardous accumulations of water, i.e., that can weaken the walls, and hinder a person’s ability to escape from an emergency situation, or otherwise endanger personnel.

5.3.3 Store excavated material at least 2 feet (0.61 meters) from the edge of excavations or use effective barriers to prevent material from falling.

5.3.4 Do not allow any person to stand under loads handled by lifting equipment.

5.3.5 Properly mark or barricade any excavations left open after working hours.

5.3.6 Observe barricading rules of the local governing authority when excavations are at road crossings. Provide high visibility vests for all personnel exposed to traffic.

5.4 Protective Systems Design

5.4.1 Design all support systems using accepted engineering principles or State requirements if they are more stringent.

5.4.2 See OSHA Regulation for sloping and trench shoring requirements.

5.5 Protection of Personnel from the Accumulation of Hazardous Vapors and Gas

5.5.1 Prior to entering an excavation, that has the potential to contain hazardous vapors or gas, the atmosphere shall be tested with an appropriate instrument, which has been calibrated prior to its use.

5.5.1.1 If the excavation does not contain a hazardous atmosphere, it may be entered but shall be monitored continuously while personnel remain in the excavation.

5.5.1.2 If the excavation contains a hazardous atmosphere, entry shall be denied. The excavation shall then be classified as a Permit required confined space and require the completion of an Entry Plan and Entry Permit before entry can be made.

5.5.2 The Company maintains the appropriate respirators and breathing apparatus for use when entry into hazardous atmosphere is necessary. Respirators shall be used in accordance with the Company respiratory protection program.

5.5.3 The Company maintains rescue harnesses and line for use in hazardous excavations.

5.5.4 If, due to the nature of the project, it is determined the Company's rescue equipment is inadequate, the local emergency response agency shall be contacted to provide assistance.

6. RELATED PROCEDURES

3.01 Damage Prevention Program
Company Confined Space Entry Procedure
Company Respirator Procedure
Company Excavating and Trenching Procedure

7. RECORDS

None required by this procedure and PHMSA regulations. Maintain copy of "Confined Space Entry permit" log as required by company OSHA policy.

FIRE FIGHTING EQUIPMENT
Hazardous Liquid Pipeline O&M Procedure #14.05

Primary Ref: 49 CFR 195.403, 195.430	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.403(a)(5), 195.430, OSHA 1910.157, NFPA 10, and local fire department requirements, if any.

2. PURPOSE

   The purpose of this procedure is to outline maintenance procedures for fire fighting equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (338) _______________ is responsible to see that appropriate fire fighting equipment is on hand where it needs to be, properly maintained, and easily accessible during a fire.

4. GENERAL

   4.1 Adequate fire fighting equipment must be maintained at each pump station and breakout tank area.

   4.2 Adequate fire fighting equipment is to be maintained at other locations as determined by the (339) _______________.

5. PROCEDURE

   5.1 The company shall develop a periodic inspection program of all fire fighting equipment, including the inspection frequency and type of service or testing required. The specific firefighting equipment and inspection frequency is detailed in the PSOM.

   5.2 The company shall provide adequate fire protection at each pump station and breakout tank. At a minimum, adequate fire protection means at least enough fire extinguishers with the ability to fight an incipient fire. The company shall follow NFPA 10 guidelines for minimum requirements for fire extinguishers.

   The firefighting equipment shall checked for proper operation as required by the manufacturer and OSHA requirements. For portable fire extinguishers the following inspections would normally be required.

- Monthly visual inspections [OSHA 29 CFR 1910.157(e)(2)]
- Annual inspection of all working parts [OSHA 29 CFR 1910.157(e)(3)]
- Pressure test of the vessel once every 6 years [OSHA 29 CFR 1910.157(e)(4)]

The firefighting equipment shall be plainly marked so that its identity as firefighting equipment is clear, and located so that it is easily accessible during a fire.

5.2 For monthly visual inspections use form #14.05 or equivalent to verify that all firefighting equipment is: [OSHA 29 CFR 1910.157 and NFPA 10]

5.2.1 In proper operating condition at all times;
5.2.2 Plainly marked as firefighting equipment;
5.2.3 Located so that it is easily accessible during a fire.

5.3 Any condition found during monthly, annual, or pressure test listed in 5.2 above or other condition imposed by local authorities that is not met, shall be remedied as soon as is practicable.

5.4 Establish inspection frequency and any other requirements not listed in this procedure per local fire department regulations.

5.5 Train operating personnel on the proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency. See O&M #16.01 (Training) for specific training requirements.

6. RELATED PROCEDURES

4.01 Scraper and Sphere Facilities
4.02 Breakout Tanks
4.03 Pumping Equipment

7. RECORDS

For monthly fire extinguisher inspections, the company shall follow NFPA 10, section 6.2.4.3 which requires records of monthly inspections be kept using one or more of the following:

1) On a tag or label attached to the fire extinguisher
2) On an inspection checklist maintained on a hard copy file
3) By an electronic method that provides a permanent record

Records of inspections shall be maintained as follows:

- Monthly fire extinguisher inspections = five years
- Annual fire extinguisher inspections = five years
- Six year pressure test of fire extinguisher vessel = life of fire extinguisher
- Other firefighting equipment inspections = five years

Training session records shall be maintained as described in O&M #16.01, Training.

PRESSURE TESTING
Hazardous Liquid Pipeline O&M Procedure #15.01

Primary Ref: 49 CFR 195.300-195.310	**Updated: Jan 2016**

1. REFERENCE

Federal: 49 CFR, Sections 195.300, 195.302, 195.303, 195.304, 195.305, 195.306, 195.307, 195.308, 195.310, 195.406, NTSB Report on San Bruno – January 3, 2011
State of California: Ca. Gov. Code 51013.5, 51014, 51014.3, 51014.5, CSFM Guide - Pressure Testing Requirements for Hazardous Liquid Pipelines in California
Industry Standards: API RP 1110 – Pressure Testing of Liquid Petroleum Pipelines, ASME B31.4 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, Section #437

2. PURPOSE

The purpose of this procedure is to establish minimum requirements for pressure testing of all hazardous liquid piping facilities installations and repairs.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (345) ______________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

4.1 No operator may operate a new segment of pipeline and applicable fittings and components or return to service a segment of pipeline that has been relocated or replaced until it has been pressure tested without leakage per the requirements of this procedure and those of Procedure 8.01, to substantiate the maximum operating pressure (MOP). All leaks and pressure and discontinuities shall be investigated to determine the cause, the cause remediated, and the cause documented for the pressure test files.

4.2 Existing pipelines that may be operated without pressure testing per this procedure are listed in 195.302(b) and shown below.

195.302(b) Exceptions: Except for pipelines converted under § 195.5, the following pipelines may be operated without pressure testing under this subpart:

(1) Any hazardous liquid pipeline whose maximum operating pressure is established under § 195.406(a)(5) [pipeline not pressure tested under subpart E - 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be

demonstrated by recording charts or logs made at the time the test or operations were conducted.] that is:

(i) An interstate pipeline constructed before January 8, 1971;

(ii) An interstate offshore gathering line constructed before August 1, 1977;

(iii) An intrastate pipeline constructed before October 21, 1985; or

(iv) A low-stress pipeline constructed before August 11, 1994 that transports HVL.

(2) Any carbon dioxide pipeline constructed before July 12, 1991, that—

(i) Has its maximum operating pressure established under § 195.406(a)(5); or

(ii) Is located in a rural area as part of a production field distribution system.

(3) Any low-stress pipeline constructed before August 11, 1994 that does not transport HVL.

(4) Those portions of older hazardous liquid and carbon dioxide pipelines for which the company has elected the risk-based alternative under § 195.303 and which are not required to be tested based on the risk-based criteria.

195.302(c) Pressure Testing Deadlines: Except for pipelines that transport HVL onshore, low-stress pipelines, and pipelines covered under § 195.303 (risk based alternative), the following compliance deadlines apply to pipelines under sections 4.2 above that have not been pressure tested:

(1) Before December 7, 1998, for each pipeline the company shall complete the following:

(i) Plan and schedule testing according to this section; or

(ii) Establish the pipeline's maximum operating pressure under § 195.406(a)(5).

(2) For pipelines scheduled for testing, the company shall complete the following

(i) before December 7, 2000:

(A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and

(B) At least 50 percent of the mileage (length) of all other pipelines; and

(ii) Before December 7, 2003, pressure test the remainder of the pipeline mileage (length).

4.3 Should a risk-based alternative to pressure testing older hazardous liquid pipelines be selected, refer to 195.303. Appendix B of 49 CFR 195 provides guidance on how the risk-based alternative works. If the risk-based alternative is chosen, test deadlines are given in Table 195.303 under 195.303(f). – FEDERAL.

NOTE: For the definition of "Higher Risk Pipelines" within the State of California, refer to Section 5.2.9 of this procedure.

4.4 Refer to Section 6.0 of this procedure for test frequency. Federal and California differ considerably.

4.5 Due to permits that may be required for water procurement and/or discharge, adequate advance design and planning must be scheduled whenever possible.

4.6 Pipeline must be backfilled as much as is practicable prior to filling the line in order to minimize pipeline expansion due to temperature changes and test pressure. Note that temperature sensors must be installed prior to backfilling at the temperature sensor location (see 9.3.3 of this procedure).

4.7 Above ground breakout tanks built after October 2, 2000, and certain tanks returned to service after that date, shall need to be pressure tested. Procedures, references, and specific details are listed in 195.307, "Pressure testing aboveground breakout tanks".

5. DEFINITIONS

5.1 Stabilization Time

The stabilization time is the time period following the fill of the system with the test medium, during which temperatures of the test medium, pipe and backfill equalize to the extent necessary to conduct a valid leak test. The time required to achieve stabilization shall depend on individual test conditions but must be sufficient to allow proper leak testing based on correlation of temperature and pressure changes during the hold period.

5.2 Leak Test

5.2.1 For piping that is entirely visible during the test, the leak test shall consist of observation of the piping while under pressure to check for visible or audible evidence of a leak.

5.2.2 For piping below ground or otherwise not visible, the leak test shall consist of an approved procedure whereby pressure variations during strength testing are accounted for, taking into account the effects of temperature and pressure on the test medium and pipe. Pressure loss that cannot be satisfactorily attributed to these factors, measurement error or other factors peculiar to the situation shall be considered evidence of a leak.

5.2.3 Strength Test

5.2.3.1 A strength test is the pressurization of piping to a minimum predetermined stress level or pressure and maintaining this stress level or pressure for a pre-determined time interval or hold period.

5.2.3.2 The hold period for the strength test shall start after the stabilization period and continue until the specified time has elapsed. During this time period the test section may be re-pressured or de-pressured as required to maintain the test pressure within the established limits. For piping below ground or otherwise not visible, maintain accurate records including de-pressuring and re-pressuring times, pressure and volumes during the hold period.

A twenty-four (24) hour hold period should be planned if at all possible. This then would allow for a complete temperature cycle.

5.2.4 Spike Test

5.2.4.1 The spike test is a variation of the hydrostatic pressure test in which a higher hydrostatic pressure, usually 139 percent of the MAOP, is applied for a short period of time (typically about 30 minutes). The spike test is intended to eliminate flaws that may otherwise grow and cause failure during pressure reduction after the hydrostatic test or resulting from normal operational pressure cycles.

It is advantageous to include a spike test because it limits the time the line is at the higher pressure to reduce the potential amount of crack growth.

For integrity program purposes, the use of a spike test, alone, as an assessment method would constitute "other technology". Operators planning to use "other technology" to perform assessments must notify PHMSA (or a state regulator) at least 180 days in advance. A spike test may be performed along with a pressure test meeting subpart J requirements. In that case, the subpart J test is considered the primary assessment, and no notification would be required. See company “Hazardous Liquid Integrity Management Plan” for details. [PHMSA Gas FAQ #141]

5.2.4 Maximum Test Pressure

The maximum test pressure is a pressure range above the specified minimum test pressure to allow for such variables as change in elevation in the test section, temperature changes, piping or equipment limitations, etc., but shall not exceed 100% SMYS of the pipe at the lowest point on the test segment.

5.2.5 Minimum Test Pressure

The minimum test pressure for a pipeline segment is 1.25 times the MOP for the first 4 hours of the test and 1.10 times the MOP for the next 4 hours of tests required for segments that are not visually inspected for leaks during the tests.

NOTE: The minimum test pressure is the test pressure required to substantiate the desired MOP. Note that although the minimum test pressure is acceptable, it is desirable to test to the maximum possible per 5.2.4 above, to maximize identification of flawed pipe, welds, or other components (i.e., leaks).

5.2.6 Pipeline Component

A pipeline component is a valve, flange, standard fitting, prefabricated assembly, or similar item.

5.2.7 Prefabricated Assembly

A prefabricated assembly is one, which is constructed prior to installation and installed as a single unit.

5.2.8 Documented Test Pressure

The pressure used for record summaries and determination of MOP shall be the minimum test pressure at the highest elevation of the pipeline during the test period.

5.2.9 Higher Risk Pipelines (CALIFORNIA)

The State Fire Marshal maintains a list of “higher risk” pipelines. This list includes pipelines which meet any of the following criteria:

5.2.9.1 Have suffered two or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion or defect in the prior three years. Note that a leak which is traceable to an external force, for which corrosion is partly responsible, shall be considered to have been caused by corrosion. “Defect” refers to manufacturing or construction defects and “leak” means a reportable rupture, per Procedures 1.01 and 1.02 of this manual.

5.2.9.2 Have suffered three or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion, defects, or external forces, but not all due to external forces, in the prior three years.

5.2.9.3 Have suffered a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or defect or more than 50,000 gallons (190 cu meters), or 10,000 gallons (38 cu meters) in a standard metropolitan statistical area, in the prior three years; or have suffered a leak due to corrosion or defect which the State Fire Marshal finds has resulted in more than 42 gallons (0.16 cu meters) of a hazardous liquid within the State Fire Marshal's jurisdiction entering a waterway in the prior three years; or have suffered a reportable leak of a hazardous liquid with a flashpoint of less than 140 degrees Fahrenheit (60°C) in the prior three years.

5.2.9.4 Are less than 50 miles (80 km) long, and have experienced a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or a defect in the prior three years. For the purposes of this paragraph, the length of a pipeline with more than two termini shall be the longest distance between two termini along the pipeline.

5.2.9.5 Have experienced a reportable leak in the prior five years due to corrosion or defect, except during a certified hydrostatic pressure test, on a section of pipe more than 50 years old. For pipelines which fall in this category, and no other category of higher risk pipeline, additional tests required by this subdivision shall be required only on segments of the pipe more than 50 years old as long as all pipe more than 50 years old which is within 20 pipeline miles (32 km) from the leak in all directions along an operator's pipeline is tested.

5.2.10 All pipelines placed on the State Fire Marshal's list shall remain there until five years pass without a reportable leak due to corrosion or defect on that pipeline. If any pipelines become eligible for the State Fire Marshal's list, they must be reported to the State Fire Marshal within 30 days, and the pipeline shall be put on the list retroactively to the date on which it became eligible for listing.

6. TEST FREQUENCY

6.1 FEDERAL

Except as otherwise provided in 195.302(b) of 49 CFR 195, no operator may operate a new segment of pipeline or return to service a segment of pipeline that has been relocated or replaced until it has been pressure tested without leakage. All testing shall be in accordance with this procedure.

6.2 CALIFORNIA

Test frequencies for regulated hazardous liquid pipelines within the State of California are listed below.

6.2.1 Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices shall be hydrostatically tested annually.

6.2.2 Every pipeline over 10 years of age and <u>not provided with effective cathodic protection</u> shall be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines (see 5.2.9 of this procedure), which shall be hydrostatically tested annually.

6.2.3 Every pipeline over 10 years of age and <u>provided with effective cathodic protection</u> shall be hydrostatically <u>tested every five years</u>, except for those on the State Fire Marshal's list of higher risk pipelines (see 5.2.9 of this procedure), which shall be hydrostatically tested every two years.

6.2.4 Piping within a refined products bulk loading facility served by pipeline shall be tested hydrostatically at 125 percent of maximum allowable operating pressure utilizing the product ordinarily transported in that piping if that piping is operated at a stress level of 20 percent or less of the specified minimum yield strength of the pipe. The frequency for pressure testing these pipelines shall be every five years for those pipelines with effective cathodic protection and every three years for those pipelines without cathodic protection. If that piping is observable, visual inspection shall be the method of testing.

6.2.5 As long as a pipeline on the State Fire Marshal's "high risk" pipeline is tested in its entirety at least as frequently as indicated in 6.2.2 or 6.2.3 above, it shall suffice for additional tests to cover 20 pipeline miles (32 km) in all directions along an operator's pipeline from the position of the leak or leaks which led to the inclusion or retention of that pipeline on the higher risk list.

7. TEST REQUIREMENTS and TEST MEDIUM (FEDERAL & CALIFORNIA)

7.1 Test medium shall be water. Liquid petroleum having a flashpoint over 140°F (60°C) may be used if it is authorized by the State Fire Marshal, is not an offshore pipeline, and if:

7.1.1 The entire pipeline section under test is outside of cities and other populated areas;

7.1.2 Each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;

7.1.3 The test section is kept under surveillance by regular patrols during the test; and

7.1.4 Continuous communication is maintained along entire test section.

7.2 Air or inert gas may be used as the test medium in low-stress pipelines. A low-stress pipeline is defined as a hazardous liquid pipeline operated in its entirety at a stress level of 20% or less of the specified minimum yield strength of the line pipe.

7.3. Facilities and piping systems require four (4) continuous hours at a pressure of at least 125% of the maximum operating pressure (MOP) if visually inspected for leakage during the test. If not visually inspected for leakage during the test, the segment being tested shall be subjected to a pressure of 110% of MOP for an additional four (4) hours. A 24-hour test should be considered.

7.4. A single pipeline component, other than pipe, installed as an addition or replacement in an operating facility is not required to be pre-or post-tested at the time of installation, provided it is not being used and the manufacturer of the component certifies that:

7.4.1 The component was tested to at least the pressure required for the pipeline to which it is being added; or

7.4.2 The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

7.5 Prefabricated assemblies are not required to be retested at the time of installation if a post installation test is impractical and they are pretested properly prior to installation.

7.6 Pipe associated with tie-ins must be pressure pretested, either with the section to be tied in or separately. Pipe used to tie-in a test segment of pipeline must have been pretested per this testing procedure, and all tie-in welds shall be 100% radio graphically inspected.

7.7 Sensitive components such as relief valves, regulators, instruments, control valves, and related items which may be damaged at elevated pressure shall either be removed or isolated from the system during testing.

7.8 CALIFORNIA-When hydro testing is required, the test results shall be certified by an independent testing firm or person who is selected from a list, provided by the State Fire Marshal.

8. PRETESTED PIPE

8.1 An unlimited length of pre-tested pipe may be used for emergency replacement. Considerable care must be taken to maintain the qualification of each joint of pre-tested pipe in the process of identification, handling, hauling, stocking, and installation. If a sufficient length of pre-tested pipe is unavailable, the remainder shall be tested at the job site.

8.2 For planned replacement of short sections, pre-tested pipe may be used. For planned replacement of longer sections, pipe shall be tested at the job location only. In-place testing is preferred, but on-site is acceptable.

8.3 Pipe stocked for emergency replacement shall be pre-tested for four (4) hours duration. See test requirements in Section 7 of this procedure.

8.4 Location of pre-tested shall be described in the PSOM.

9. PRESSURE & TEMPERATURE CHARTS

9.1 General Requirements

9.1.1 Calibrated and certified pressure and temperature recorders shall be used, except that fluid temperature recording is not required on any test of aboveground piping that can visually be inspected for leaks. It is recommended to also use a calibrated and certified pressure gage. A dead-weight tester for pressure calibration is also required and the following must be met:

9.1.1.1 Dead weight pressure is obtained at time intervals not exceeding 15 minutes, and

9.1.1.2 If a dead weight pressure is less than the minimum test pressure, the test is restarted, and

9.1.1.3 The dead weight pressure, the corresponding time, and the ambient temperature shall be recorded.

9.2 Pressure Charts

9.2.1 The date and the time test is started and the time at which the test period ends shall be noted on the chart.

9.2.2 Charts must show "pressure up" line and "bleed down" line, as well as recording of pressure during the test interval.

9.2.3 Drastic deviations in the recorded pressure or any discontinuities, including test failures, shall be noted and explained.

9.2.4 The facility being tested shall be identified by pipeline name and/or number or Work Order number on the chart.

9.2.5 If more than one test section is involved in the Work Order or project, the test section number and location by station number or mile post for pipelines, or drawing number for stations, shall also be indicated.

9.2.6 Charts shall be signed by an authorized Company representative and Test Contractor's representative or test technician.

9.3 Temperature Charts - Test Fluid

9.3.1 Temperature recordings shall be started prior to the start of the fill operation when hydrostatic testing.

9.3.2 Identification information and signatures shall be the same as for pressure charts.

9.3.3 Temperature sensing devices must be placed on the pipeline below grade and shaded from the sun to prevent erroneous readings.

10. PROCEDURE

10.1 Testing shall be conducted in accordance with a pre-established test plan, which shall be reviewed and approved prior to the start of test. Approval may be necessary from regulatory agencies as well as a county or city. Use appendix #15.01-A for list of information and data to be completed as part of the test plan.

10.2 The test medium must be water, except as indicated in 7.1 of this procedure. In any case, the liquid must be:

10.2.1 Compatible with material of the pipeline;

10.2.2 Relatively free of sedimentary materials.

10.3 Do not test against closed valves, unless absolutely necessary. If testing against closed valves, verify with the manufacturer that the test pressure shall not damage the valve.

10.4 For fabricated units and short sections of pipe to be installed in any type facility for which a post installation test is impractical, a pre-installation test of four (4) hours minimum duration may be used provided all the piping is visible and is checked for leaks periodically during the test.

10.5 Fabricated assemblies, including line valve assemblies, cross connections, river crossing headers, etc., which have been appropriately pre-tested shall be tested in the same manner, to at least the same pressure as the pipeline on either side of the assembly.

10.6 The leak test pressure for a hot tap or stopple connection after welding to the header pipe and prior to tapping shall be the operating pressure at the time of tapping and for 30 minutes duration.

11. WATER REMOVAL

11.1 Pigs and squeegees in good condition, where practical, shall be used to dry long test sections.

11.2 Pig runs shall be made and repeated as necessary to remove all free water. Normally, the test section shall be considered satisfactorily dry when no water or mist is expelled ahead of the pig and no water can be wrung from a poly foam pig.

11.3 For test sections where water or water vapor remaining in the test section shall cause future operating problems, the test section shall be further dried using dehydrated air or other means deemed suitable and necessary. Methanol injection shall not normally be approved due to environmental restrictions.

12. CRITERIA for TEST ACCEPTANCE

The company pipeline engineer, contract pipeline engineer, or equivalent shall review the pressure test records to determine if the test is acceptable under CSFM regulations and CSFM Guide -Pressure Testing Requirements for Hazardous Liquid Pipelines in California. [Ca. Gov. Code 51010] The engineer shall use template form #15.01B (Criteria for Test Acceptance) to document the review and acceptance. CSFM allowable loss rate equals 1.036 gallons/hour ~~per~~.

13. RELATED PROCEDURES

5.01 Continuing Surveillance
15.02 Visual Inspection and Nondestructive Testing

14. RECORDS

14.1 Use form #15.01 (Pressure Test Documentation) or eqvalent to record at least the following information:

14.1.1 The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used including employee involved.

14.1.2 A description of the facility tested and the test apparatus.

14.1.3 Elevation variations, whenever significant for the particular test. Where elevation differences in the test section exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section is required.

14.1.4 Test medium used.

14.1.5 Minimum test pressure.

14.1.6 Test duration.

14.1.7 Pressure recording charts, or other record of pressure readings.

14.1.8 Elevation variations, whenever significant for the particular test. Where elevation differences in the test section exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section is required.

14.1.9 An explanation of any pressure discontinuities, including leaks and failures noted that appear on the pressure recording charts.

14.1.10 Test instrument calibration data including make, model and serial number of dead weight tester and date of last certification test.

14.1.11 Description of the facility tested and the test apparatus.

14.1.12 Temperature of the test medium or pipe during the test period.

13.1.13 A copy of the facility specific testing plan described in section #10.1 above. Facility specific testing plan shall include a review and approval prior to the start of test. Approval may be necessary from regulatory agencies as well as a county or city.

14.2 Use template form #15.01B (Criteria for Test Acceptance) or equivalent to review and accept or reject pressure test. CSFM allowable loss rate equals 1.036 gallons/hour ~~per~~.

14.3 Verify and keep operator qualification records of the person conducting the pressure test. See company OQ plan for details.

For hazardous liquid pipelines in California this means the pressure testing contractor has been through CSFM pressure test training. The company can verify that the pressure test contractor is certified by reviewing the list on the CSFM website: http://osfm.fire.ca.gov/pipeline/pipeline_hydrotest.php

14.4 All required test forms, pressure charts, and temperature charts shall be retained for the life of the pipeline facilities.

Hydro Test Plan Procedure Considerations [API RP #1110, section #3.6
Hazardous Liquid Pipeline O&M Procedure

Appendix #15.01-A **Updated: Jan 2016**

Before testing begins, a pressure test procedure with explanatory notes and data should be prepared by the pipeline engineer or designee. This detailed procedure should provide the following:

1) A diagram indicating the lengths, elevations, and locations of the test segments, including any tested piping manifolds, and set-up of test equipment.

   Locate the taps for the pressure recording devices on the pipeline. Do not locate the taps on or near the high pressure fill piping. The taps should be located several feet from the high pressure pump injection point in order for the readings to be accurate during the pressurization process
2) The test medium to be used, fill rates, and the line fill volumes for filling and at test pressure
3) Methods for cleaning, decommissioning, filling, and re-commissioning test segments
4) Methods for pressurizing the test segments. These methods should indicate the locations of the injection points with respect to recording locations and should provide the specified minimum and maximum test pressures
5) Methods for isolating the test segments. These methods should indicate which blinds and plugs to install, valves to remove, and cathodic rectifier systems to be de-energized
6) The minimum test duration for test segments
7) Methods for removing and disposing of the test medium
8) Safety precautions and procedures
9) An identification of and a specification for the weakest link or controlling component in the test section

The specified test pressure is the minimum test pressure that should be applied to the most elevated point in the test segment. This elevation is not necessarily that of the deadweight tester; therefore, it should be corrected for elevation difference between the pipeline and deadweight tester.

The minimum test pressure should be in accordance with ASME B31.4 and 49 Code of Federal Regulations Part 195. A detailed analysis of the profile to determine what the pressures shall be during the test should be performed so that the pipeline shall not be over pressured at points that are at low elevations. Since the test pump and recording equipment are not necessarily at the highest elevation, test personnel should be provided with precise target pressures for the elevation at the pump and recorders

VISUAL INSPECTIONS & NDT
Hazardous Liquid Pipeline O&M Procedure #15.02

Primary Ref: 49 CFR 195.212, 228, 234	**Updated: Jan 2016**

1. REFERENCE

   49 CFR, Sections 195.212(c), 195.228, 195.234, API Standard 1104, and ASNT Recommended Practice SNT-TC-1A.

2. PURPOSE

   The purpose of the procedure is to establish minimum requirements for visual inspection and nondestructive testing of field made butt welds in piping to be operated under pressure.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (351) _______________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

   4.1 All visual inspection and nondestructive testing of field made butt welds in hazardous liquid piping shall be in accordance with the DOT referenced edition, API Standard 1104 "Welding of Pipelines and Related Facilities" (49 CFR 195 currently referenced edition).

   4.2 Radiographic inspection or ultrasonic inspection shall be used to satisfy the requirements for nondestructive testing of field made girth welds.

   4.3 Persons nondestructively testing welds shall be trained and qualified to a Level II status in order to perform tests and interpret results in the testing method employed, per written nondestructive testing procedures, and be familiar with all requirements of the currently referenced edition of API Standard 1104.

   4.4 The acceptability of a weld that is nondestructively tested or visually inspected, is determined according to the standards in Section 9 of API Standard 1104, (49CFR 195 currently referenced edition).

      4.4.1 If a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

4.5 Welding Inspector shall be qualified to perform visual weld inspection.

Qualification means training of testing personnel of NDT technicians certified under ASNT Recommended Practice SNT-TC-1A. The company should obtain copies of the qualification, review and approve before the work begins.

When the company inspects welds using NDT, interpretation personnel shall be qualified to ASNT Recommended Practice Level II or Level III. (API 1104)

5. WELD NONDESTRUCTIVE TESTING

5.1 Any process, other than trepanning, that shall clearly indicate defects that may affect the integrity of the weld, must perform nondestructive testing of welds.

5.2 Each weld that is found unacceptable must be removed or repaired, and then found acceptable. Except for welds on an offshore pipeline being installed from a pipe laying vessel, a weld must be completely removed if it has a crack that is more than 8% of the weld length.

5.3 Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair.

5.4 After repair, the segment of the weld that was repaired must be inspected to insure its acceptability.

5.5 Ensure the interpretations of all nondestructive test results by Nondestructive Testing Contractor are correct.

5.6 Follow the schedule in table 15.02 of this procedure for the minimum percentage of each day's field butt welds to be nondestructively tested over entire circumference.

5.7 At least 10% of each welder's daily welds, during construction, shall be nondestructively tested over the entire circumference of the weld.

6. WELD VISUAL INSPECTION

6.1 Each weld and welding of a regulated pipeline shall be visually inspected by a qualified inspector to insure that:

6.1.1 The welding is performed in accordance with the welding procedures;

6.1.2 The welds are acceptable to the standards in Section 6 of API Std 1104, (49CFR 195 currently referenced edition).

6.1.3 The welds conform to the requirements of "Pipeline Welding" Procedure 9.06 and this "Visual Inspection and Nondestructive Testing" Procedure.

6.2 Ensure that each joint of pipe is inspected for defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.3 Bevels shall be inspected for proper dimensions, cleanliness and angle.

6.4 Ensure that each joint of pipe is swabbed as necessary to remove all dirt and foreign materials from the inside.

6.5 Ensure that the longitudinal seams are offset as stated in Procedure 9.06. The line up shall be inspected to ensure proper root spacing and alignment.

6.6 The stringer (root) bead shall be inspected for proper grinding and cleaning.

6.7 If more than one grade or weight of pipe or fittings are used, ensure that it is according to the approved construction drawings.

6.8 Mark and ensure that all arc burns are removed and repaired according to Procedure 9.06.

7. RELATED PROCEDURES

9.06 Pipeline Welding
15.01 Pressure Testing

8. RECORDS

8.1 Develop a record keeping system for location of non-destructive tested welds on stations (i.e., compressor stations, meter stations, etc.) piping to ensure that girth welds on pressurized piping have been nondestructively tested in the correct amount (show in station piping drawings).

8.2 Record to show by milepost, station plus, or by geographic feature, the location of girth welds made, the number of nondestructively tested, the number rejected, and the disposition of the rejects. (Show on alignment sheets).

8.3 Retain the above records for the life of the pipeline system.

8.4 Record results from radiograph films and ultrasonic testing with a unique numbering system allowing identification of the radiograph film or ultrasonic testing results to its respective weld.

8.5 Radiographic film must be retained for at least one year. However, as indicated above, the certification sheets and other records showing the disposition of the welds must be retained for the life of the pipeline.

TABLE 15.02
MINIMUM VISUAL INSPECTION & NONDESTRUCTIVE TESTING REQUIREMENTS FOR PRESSURIZED PIPING

Pipeline Locations	Visual Inspection	Non-Destructive Testing
Any Offshore Area	100%	100%(2)
Stream, River, Lake, Reservoir, or other body of Water (3)	100%	100%(2)
Railroads or Public Road Rights-of-Way (4)	100%	100%(2)
Road Crossings and Tunnels (5)	100%	100%(2)
Incorporated Subdivision of a State Government (6)	100%	100%(2)
Populated Areas (7)	100%	100%(2)
Used Pipe (8)	100%	100%
Tie-in's (9)	100%	100%
Pipe Bends (10)	100%	100%
Repaired Welds (11)	100%	100%(2)
Other Locations	100%	10%(1)

NOTES:

1. At least 10% of the girth welds made by each welder, during each welding day, must be nondestructively tested over the entire circumference of the weld.
2. All girth welds installed each day must be nondestructively tested over the entire circumference of the weld unless impracticable, in which case 90% must be tested (i.e., nondestructive testing must be impracticable for each girth weld not tested).
3. At any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water.

4. Within railroad or public road rights-of-way.
5. At overhead road crossings and within tunnels.
6. Within the limits of any incorporated subdivision of a State government.
7. Within populated areas, including, but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.
8. When installing used pipe, 100% of the old girth welds must be nondestructively tested.
9. At pipeline tie-ins, including tie-ins of replacement sections, 100% of the girth welds must be nondestructively tested.
10. Each circumferential weld, which is located where the stress during bending causes a permanent deformation in the pipe, must be nondestructively tested either before or after the bending process.
11. Welds repaired due to nondestructive testing rejection, must be re-tested over the entire weld length.
12. Inspection of repaired welds must be performed using the method of inspection used to identify original defect.

TRAINING
Hazardous Liquid Pipeline O&M Procedure #16.01

Primary Ref: 49 CFR 195.50 - 195.62	Updated: Jan 2016

1. REFERENCE

   49 CFR, Sections 195.403 and 195.555.

2. PURPOSE

   The purpose of the procedure is to outline the minimum training requirements for hazardous liquid pipeline operating, maintenance, and supervisory personnel.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (357) ______________ is responsible for establishing and conducting a continuing training program that meets the requirements of this procedure.

4. GENERAL

   4.1 The company shall develop a training program as shown in appendix #16.01-A that shall include instructing operating and maintenance personnel to comply with the following:

   4.1.1 For each employee involved in jurisdictional pipeline O&M, a basic job description, basic work history, training history, list of required training including frequency, and gaps or action plan to meet company training requirements.

   4.1.1 Carry out the appropriate operating and maintenance procedures that relate to their job assignments. The procedures are contained in this Operations & Maintenance Manual and the appropriate Pipeline Specific Operations Manual.

   4.1.2 Carry out the appropriate emergency procedures that relate to their job assignments as presented in Procedure 3.04, in this Operations & Maintenance and the appropriate Pipeline Specific Emergency Plan.

   4.1.3 Know the characteristics and hazards of the hazardous liquids transported. This is the covered in annual HAZWOPER training.

   4.1.4 Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquid spills, and to take appropriate corrective action.

4.1.5 Take steps necessary to control any accidental release of hazardous liquid and to minimize the potential for fire, explosion, or toxicity, or environmental damage.

4.1.6 Learn the proper use of available fire fighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

4.1.7 In the case of maintenance personnel, to safely repair facilities using appropriate precautions, such as isolation and purging, when hazardous liquids are involved.

4.1.8 Recognize conditions that potentially may be safety related conditions that are subject to the reporting requirements of 195.55.

4.1.9 The company shall verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.402(c)(3) for which they are responsible for insuring compliance.

5. PROCEDURE

5.1 Establish a training program meeting, at a minimum, the requirements outlined in paragraph 4, above.

5.2 At intervals not exceeding 15 months, but at least once each calendar year:

5.2.1 Review with personnel their performance in meeting the objectives of the training.

5.2.2 Make appropriate changes to the training program as necessary to insure that it is effective.

5.3 Require and verify that supervisors maintain a thorough knowledge of the procedures established in this Operations & Maintenance Manual including corrosion control procedures for which they are responsible for insuring compliance, the appropriate Pipeline Specific Operations Manuals and the appropriate Pipeline Specific Emergency Plans.

6. RELATED PROCEDURES

Appropriate Procedures in this Operations & Maintenance Manual.
Appropriate Pipeline Specific Emergency Plans.
Appropriate Pipeline Specific Operations Manuals.

7. RECORDS

Maintain all training records of all personnel for the life of the pipeline.