Executive Information Bulletin

Pipeline and Hazardous Materials Safety Administration (PHMSA)

Subject: ExxonMobil Pipeline Crude Oil Spill, Yellowstone River near Laurel, MT	[] Original [X]Update	Issued: 07-07-11 1130
Date and time current information received: 07-06-11 2356 **Information source(s): NRC Report 981503; Reports from PHMSA Western Region**		
Location: Yellowstone River near Laurel, MT		
Date and time original incident discovered: 07-02-11 1:45 a.m. EDT **Date and time reported to NRC: 07-02-11 2:19 a.m. EDT**		

UPDATE: (07-07-11 1130) PHMSA's Western Region Director (RD) and an inspector are on site. PHMSA's RD attended a community meeting in Laurel concerning the spill. He reported there were more than 130 citizens at the meeting.

PHMSA staff visited the South Bank of the Yellowstone River, near the Rt. 212 bridge with a Laurel City Official. PHMSA continues reach out to local officials, monitor operations at the site, and support the Unified Command.

UPDATE: (07-06-11 1800) PHMSA's Western Region Director (RD) and an inspector are on site. The Director has conferred with EPA's Regional Administrator, the President of ExxonMobil Pipeline, and City Officials. He also traveled to the site and viewed the area of the failed pipeline's river crossing.

The RD will attend a community meeting in Laurel this evening and meet with city and county officials tomorrow, to discuss actions that are being taken to assess other pipeline crossings in the state.

PHMSA's Western Region has contacted the operators of all hazardous liquid pipelines with river crossings in Montana, to determine the operation, status, and means used to construct each crossing.

UPDATE: (07-06-11 0900) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. A second PHMSA staff member is expected to arrive later today.

Corrective Action Order: PHMSA issued a Corrective Action Order (CAO) to ExxonMobil (EM) Pipeline Company on Tuesday, July 5, 2011, that will require the company to take several actions to improve safety along the Silvertip pipeline. The CAO is posted on the PHMSAnet site.

PHMSA's Western Region Office reports:

- PHMSA's investigation continues, including a detailed examination of pertinent procedures and records.
- A PHMSA inspector visited the EM Operation Control Center in Houston, TX Tuesday afternoon. Records from the SCADA (operational control) systems were obtained and analyzed as part of PHMSA's ongoing investigation.
- The operator will add approximately 100 additional personnel to the clean-up operations today. The total on site response team is over 400.

UPDATE: (07-05-11 1830) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. A second PHMSA staff member is expected to arrive tomorrow. PHMSA's Western Region reports:

- Montana Governor Brian Schweitzer was in Billings this morning and held a press conference in the same

venue as the Incident Command Post. He also visited cleanup sites.

- Montana Congressman Rehberg, along with staff members for Senators Baucus and Tester, and city representatives from Laurel and Billings also attended the conference.
- PHMSA's Western Region Office staff is contacting hazardous liquid pipeline operators in Montana to gather additional information on river crossings.

NOTE: All concerned are reminded to be conscious of time zone differences involved in this incident. The National Response Center operates in the Eastern Time Zone; the pipeline's Control Center operates in the Central Time Zone; and the incident occurred in the Rocky Mountain Time Zone.

UPDATE: (07-05-11 1100) Two PHMSA Western Region Pipeline Safety inspectors are on site and positioned at the Incident Command Post. PHMSA's Western Region reports:

- The Western Region Director has conferred with the EPA Onscene Coordinator, and is providing information on each pipeline having a Yellowstone River crossing.
- U.S. EPA Region VIII Administrator, James B. Martin, was reported to be on scene on Monday.
- Montana Governor Brian Schweitzer will be visiting Billings on Tuesday, July 5, 2011.
- Governor Schweitzer was reported on Monday to have said that authorities would review the safety of all oil and gas pipelines that cross waterways in the state and close those that did not meet standards.
- PHMSA spoke with the Public Works Directors at Billings and Laurel, MT, who said that the municipal water intakes are operational and that water sampling continues.
- A PHMSA Accident Investigator will visit the ExxonMobil Control Center in Houston on Tuesday to review SCADA records.
- PHMSA was informed that the crude oil in the pipeline was from domestic production.

UPDATE: (07-04-11 1730) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. PHMSA's on site inspector reported from this morning's operations briefing:

- **Today is a day of transition from EM Pipeline Company's operational control of the incident to Exxon's North American Regional Response Team (NARRT). More personnel are en route.**
- **This is a unified command with by EPA representing the Federal Government, the State of Montana, and ExxonMobil.**
- **Today response objectives are:**
  - **Environmental is to ID special environmental risks in spill vicinity. A special environmental concern area has been identified near Hysham, MT approximately 105 miles downstream from the spill site.**
  - **Exxon's Shoreline Cleanup Assessment Team (SCAT) is to conduct shoreline and floodplain assessment**
  - **Operations will Conduct cleanup according to the SCAT assessment, right now in Division A and Division B.**
  - **Engage local landowners to prioritize cleanup in communities and private properties.**
  - **Develop a right speed notification and response action process to more rapidly respond to public reports of oil spill impacts.**
- **There has been one unconfirmed report of an oiled goose.**

[The following information was provided to the distribution list earlier today.]

- Another Inspector from PHMSA's Western Region is en route to relieve our current inspector later today.
- PHMSA's Inspector at the scene reports that the focus of oil recovery efforts today (July 4, 2011) will be in the area up to about 3 miles downstream of the incident, and reconnaissance will concentrate on assessing the amount of oil from 20 to about 200 miles downstream.
- Overflights made yesterday (07-03-11) found small oil deposits as far as Terry, MT, approximately 240 river miles downstream.
- The pipeline operator, ExxonMobil (EM), reported that approximately 120 persons were involved in response operations yesterday, and as many as 200 are expected to be on scene today (07-04-11). EM has established a toll-free number for reporting oil-related damage claims.

- A Federal Onscene Coordinator from U.S. Environmental Protection Agency (US EPA) Region VIII is overseeing response operations.
- The operational command post is located in Coulson Park in Billings, MT, and the general staff is operating from a local hotel.
- Representatives from the U.S. Coast Guard's National Strike Force arrived yesterday, and are involved in response activities.
- EPA's Regional Administrator from Denver will be in Billings today.
- Montana Governor, Brian Schweitzer, will be visiting the site on Tuesday (07-05-11).
- PHMSA's Western Region Office is conferring with local officials in the Laurel and Billings area.

UPDATE: (07-04-11 1030) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. The Federal Onscene Coordinator (FOSC) is scheduled to conduct a briefing at 11:00 a.m. EDT for incident responders.

PHMSA contacted all pipeline operators with lines that cross the Yellowstone River from Park City to the west to east of Billings, MT

- KMEP's Express Pipeline near Park City
- Plains All-American/Rocky Mountain/Beartooth Pipeline –just west of Billings
- ConocoPhillips Glacier

PHMSA Western Region provided this summary of PHMSA's recent inspection activities concerning the EM 12-inch crude pipeline at Laurel, known as the Silvertip line.

- **July 27- 30, 2009** - standard inspection performed on the PL 12-inch Silvertip Pipeline - several potential violations identified (Yellowstone River crossing issues were not any of them). These inspections resulted in three enforcement letters 5-2010-5019W and 5-2010-5020M (dated June 8, 2010) and NOPV/PCO 5-2011-5003 (dated 2/23/11). The 2010 cases have been closed and the 2011 NOPV has been recommended for closure.
- **October 2010** - Public Inquiry received from the City of Laurel regarding pipelines crossing the river adjacent to Riverside Park south of Laurel. The issue pertained to possible erosion of the riverbank/berm on the south side of the Yellowstone River during high runoff events and whether pipelines could be affected in the event the bank eroded to the point where the Yellowstone River flowed into/through Riverside Park. PHMSA inspector met with staff from the city of Laurel and EM. EM agreed to perform a depth of cover survey across the river and the park.
- **December 1, 2010** – EM completed the depth of cover survey on the 12-inch pipeline crossing of the Yellowstone River.
- **January 2011** – EM provided PHMSA a copy of the recently completed depth of cover survey across the Yellowstone River. Pipeline depths appeared to be adequate across the river. Note: for water crossings over 100 feet, the mandated depth of cover is 4 feet. Schematic shows at least 5 feet of cover at all measured points.
- **Early May 2011** - PHMSA Inspector conducted a follow up inspection with EM personnel to conduct field verifications that they had completed the proposed compliance order items.
- **Late May 2011** - High Yellowstone River level from heavy rainfall causes some minor flooding of Riverside Park. PHMSA Inspector made several trips to the park to photograph the progression of any bank erosion. There was some erosion but it did not appear to be very significant.
- **June 1, 2011** – PHMSA contacted EM about depth of cover on south side of creek. City of Laurel and PHMSA were both concerned about erosion. EM informed depth of cover at banks was averaging 12 feet and we relayed that to the City of Laurel staff.
- **June 6-10, 2011** - Inspection (IMP Field Activity Inspection) performed on the EM 12-inch Silvertip Pipeline - reviewed ILI tool run data from 2004 and 2009. (Note: All of the raw data from the 2009 ILI run was reviewed - not just a summary report). Data and repairs performed on the line looked good. There was one minor defect identified under the Yellowstone River but it was quite a bit below reaching the repair criteria outlined in the

Part 195.

UPDATE: (07-03-11 1700) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. Clean-up operations are underway. Drinking water intakes for Billings and Lockwood that were closed immediately after the leak have been re-opened. Water quality checks at Billings and Lockwood continue, along with downstream monitoring to check for impacts to agricultural and other water supplies.

UPDATE: (07-03-11 1030) A PHMSA Western Region Pipeline Safety inspector is on site and positioned at the Incident Command Post. Davis Romero, a U.S. Environmental Protection Agency Federal On-Scene Coordinator (FOSC), is at the scene and has activated a U.S. Coast Guard (USCG) response unit and a response contractor. Response activities are expected to be in full operation on Sunday, July 3, 2011. The Incident Command Post is being moved from Coulson Park to the ExxonMobil refinery.

UPDATE: (07-02-11 1700) PHMSA's Western Region Pipeline Safety Office reports that their inspector arrived on site in mid-afternoon and is positioned at the Incident Command Post. ExxonMobil Pipeline (EMPL) has estimated that between 750 and 1,000 barrels (31,500 and 42,000 gallons) of crude oil were released.

PHMSA has been in contact with all pipeline operators in the upper Missouri River and its tributaries area for about a month, in anticipation of flooding in the area. Information provided by PHMSA's Western Region follows:

Leak Location and Details:

- The suspected EMPL leak site is at the 12-inch pipeline Yellowstone River crossing near the town of Laurel, MT. Laurel, MT about 20 miles upstream of Billings, Montana.
- A recent EMPL depth of cover survey at this location indicated approximately 5-8 feet of cover over the pipeline. Current water depth at the location is estimated at 18 feet.
- The Yellowstone River flows from Yellowstone Lake in Yellowstone Park into Montana.
- An aerial overflight this morning reported an estimated 100 yd by 25 yd patch of oil in the river close to the city of Billings.

Clean-up:

- The Oil Spill Response Organization (OSRO) has been activated and arriving at the scene.
- Local responders, EMPL, and contract cleanup crew are also on site.
- Vacuum trucks are on location, and being used for shoreline oil pickup

Media reports indicate that U.S. Environmental Protection Agency (US EPA)'s Denver Office is dispatching personnel to oversee spill response operations.

EMPL has confirmed that water intakes for the city of Lockwood and the city of Billings have been temporarily closed.

ORIGINAL INFORMATION: (07-02-11 1130)
At about 2:30 a.m. EDT, ExxonMobil (EM) Pipeline Company reported the failure of a crude oil pipeline at its Yellowstone River crossing, near Laurel, MT. The operator reports that the pipeline failed in an area of heavy flooding and valves were closed to isolate the leaking segment. At about the same time, local responders called the EM Control Center, reporting the odor of crude oil in the area. EM Spill response personnel were mobilized from the Billings Refinery in addition to local emergency responders.

EM is working to develop an estimate of the amount spilled. PHMSA's Western Region Pipeline Safety Office has dispatched an inspector to the scene, who is expected to arrive at the scene by mid-afternoon.

Keener, Blaine (PHMSA)

From: HQS-PF-fldr-NRC@uscg.mil
Sent: Monday, July 11, 2011 4:20 PM
To: PHP Accident/Incident Cadre <PHMSA>; CMC-01 (OST)
Subject: NRC#982358

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 982358

INCIDENT DESCRIPTION

*Report taken by: PO2 BRIAN DOVE at 16:08 on 11-JUL-11
Incident Type: PIPELINE
Incident Cause: FLOOD
Affected Area: YELLOWSTONE RIVER
Incident occurred on 01-JUL-11 at 22:40 local incident time.
Affected Medium: WATER / YELLOWSTONE RIVER

REPORTING PARTY

Name: THAD MASSENGALE
Organization: EXXON MOBIL PIPELINE COMPANY
Address: 800 BELL STREET
ROOM 623F
HOUSTON, TX 77002

PRIMARY Phone: (713)6562258 ALTERNATE Phone: (281)3814131
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: LARRY HAWTHORNE
Organization: EXXON MOBIL PIPELINE
Address: 800 BELL STREET >
ROOM 623F
HOUSTON, TX 77002
PRIMARY Phone: (903)8790313

INCIDENT LOCATION

County: YELLOWSTONE
City: LAUREL State: MT
YELLOWSTON RIVER

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

THIS IS AN UPDATE TO NRC REPORT NUMBER 981874. CALLER UPDATED THE TIME THE INCIDENT OCCURRED FROM 2345 MOUNTAIN TIME TO 2240 LOCAL MOUNTAIN TIME. INITIAL INCIDENT DESCRIPTION: PIPELINE HAS BROKEN IN

THE RIVER RELEASING CRUDE OIL. THE DAMAGE WAS CAUSED BY RIVER FLOODING.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: YES
Pipeline Covered: YES
---WATER INFORMATION---
Body of Water: YELLOWSTONE RIVER
Tributary of:
Nearest River Mile Marker:
Water Supply Contaminated: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES:	NO	Hospitalized:	Empl/Crew:	Passenger:
FATALITIES:	NO	Empl/Crew:	Passenger:	Occupant:
EVACUATIONS:	NO	Who Evacuated:	Radius/Area:	

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air:	N		
Road:	N		Major Artery:N
Waterway:	N		
Track:	N		

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

VALVES WERE CLOSED TO STOP THE FLOW OF THE PIPELINE.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: RAINY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: FD
State/Local On Scene: FD

State Agency Number: NONE

NOTIFICATIONS BY NRC

DHS NOC (NOC)
11-JUL-11 16:19 (202)2828114
USCG ICC (ICC ONI)
11-JUL-11 16:19 (301)6693363
USDA (MAIN OFFICE)
(202)2050906
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
11-JUL-11 16:19 (202)3661863
U.S. EPA VIII (MAIN OFFICE)
(303)2931788
FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
11-JUL-11 16:19 (800)6347084
INFO ANALYSIS & INFRA PROTECTION (MAIN OFFICE)
11-JUL-11 16:19
MT DEPT OF ENVIRONMENTAL QUALITY (MAIN OFFICE)
11-JUL-11 16:19 (406)4440379
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
11-JUL-11 16:19 (202)2829201
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11-JUL-11 16:19 (202)2829201
NOAA RPTS FOR MT (MAIN OFFICE)
11-JUL-11 16:19 (206)5264911
NTSB PIPELINE (MAIN OFFICE)
(202)3146293
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
11-JUL-11 16:19 (202)3660568
DOI/OEPC DENVER (MAIN OFFICE)
11-JUL-11 16:19 (303)4452500

ADDITIONAL INFORMATION

THIS IS AN UPDATE TO NRC REPORT 981874.

*** END INCIDENT REPORT #982358 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

Keener, Blaine (PHMSA)

From: HQS-PF-fldr-NRC@uscg.mil
Sent: Wednesday, July 06, 2011 5:25 PM
To: PHP Accident/Incident Cadre <PHMSA>; CMC-01 (OST)
Subject: NRC#981874

NATIONAL RESPONSE CENTER 1-800-424-8802
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applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 981874

INCIDENT DESCRIPTION

*Report taken by: CIV LOTTIE JOHNSON at 17:10 on 06-JUL-11
Incident Type: PIPELINE
Incident Cause: FLOOD
Affected Area: YELLOWSTONE RIVER
Incident occurred on 01-JUL-11 at 23:45 local incident time.
Affected Medium: WATER / YELLOWSTONE RIVER

REPORTING PARTY

Name: LARRY HAWTHORNE
Organization: EXXON MOBIL PIPELINE
Address: 800 BELL ST.
HOUSTON, TX
EXXON MOBIL PIPELINE reported for the responsible party.
PRIMARY Phone: (903)8790313
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: LARRY HAWTHORNE
Organization: EXXON MOBIL PIPELINE
Address: 800 BELL ST.
HOUSTON, TX
PRIMARY Phone: (903)8790313

INCIDENT LOCATION

County: YELLOWSTONE
City: LAUREL State: MT
YELLOWSTONE RIVER

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

THIS IS AN UPDATE TO REPORT #981503 AND 981703. CALLER IS REPORTING THAT THE INCIDENT OCCURRED 2345 MOUNTAIN TIME. CALLER IS REPORTING THAT A PIPELINE HAS BROKEN IN THE RIVER RELEASING CRUDE OIL. THE DAMAGE WAS CAUSED BY RIVER FLOODING.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: YES
Pipeline Covered: YES
---WATER INFORMATION---
Body of Water: YELLOWSTONE RIVER
Tributary of:
Nearest River Mile Marker:
Water Supply Contaminated: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:UNKNOWN Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air:	N		
Road:	N		Major Artery:N
Waterway:	N		
Track:			

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

VALVES WERE CLOSED TO STOP THE FLOW OF THE PIPELINE
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: RAINY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: FD
State/Local On Scene: FD
State Agency Number: NONE

NOTIFICATIONS BY NRC

DHS NOC (NOC)
06-JUL-11 17:24 (202)2828114
USCG ICC (ICC ONI)
06-JUL-11 17:24 (301)6693363
USDA (MAIN OFFICE)
(202)2050906
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
06-JUL-11 17:24 (202)3661863
U.S. EPA VIII (MAIN OFFICE)
(303)2931788
FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
06-JUL-11 17:24 (800)6347084
INFO ANALYSIS & INFRA PROTECTION (MAIN OFFICE)
06-JUL-11 17:24
MT DEPT OF ENVIRONMENTAL QUALITY (MAIN OFFICE)
06-JUL-11 17:24 (406)4440379
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
06-JUL-11 17:24 (202)2829201
NATIONAL INFRASTRUCTURE COORD CTR (INFRASTRUCTURE PROTECTION)
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NOAA RPTS FOR MT (MAIN OFFICE)
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NTSB PIPELINE (MAIN OFFICE)
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PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
06-JUL-11 17:24 (202)3660568
DOI/OEPC DENVER (MAIN OFFICE)
06-JUL-11 17:24 (303)4452500

ADDITIONAL INFORMATION

CALLER HAD NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT #981874 ***

Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

Keener, Blaine (PHMSA)

From: HQS-PF-fldr-NRC@uscg.mil
Sent: Saturday, July 02, 2011 2:29 AM
To: PHP Accident/Incident Cadre <PHMSA>; CMC-01 (OST)
Subject: NRC#981503

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
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applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 981503

INCIDENT DESCRIPTION

*Report taken by: MST3 RUDOLPH GANTHER at 02:19 on 02-JUL-11
Incident Type: PIPELINE
Incident Cause: FLOOD
Affected Area: YELLOWSTONE RIVER
Incident was discovered on 02-JUL-11 at 00:45 local incident time.
Affected Medium: WATER YELLOW STONE RIVER

REPORTING PARTY

Name: LARRY HAWTHORNE
Organization: EXXON MOBIL PIPELINE
Address: 800 BELL ST.
HOUSTON, TX
EXXON MOBIL PIPELINE reported for the responsible party.
PRIMARY Phone: (903)8790313
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: LARRY HAWTHORNE
Organization: EXXON MOBIL PIPELINE
Address: 800 BELL ST.
HOUSTON, TX
PRIMARY Phone: (903)8790313

INCIDENT LOCATION

YELLOWSTONE RIVER County: YELLOWSTONE
City: LAUREL State: MT

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

CALLER IS REPORTING THAT A PIPELINE HAS BROKEN IN THE RIVER
RELEASING CRUDE OIL. THE DAMAGE WAS CAUSED BY RIVER FLOODING.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: YES
Pipeline Covered: YES
---WATER INFORMATION---
Body of Water: YELLOWSTONE RIVER
Tributary of:
Nearest River Mile Marker:
Water Supply Contaminated: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air: N			
Road: N			Major Artery:N
Waterway: N			
Track:			

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

VALVES WERE CLOSED TO STOP THE FLOW OF THE PIPELINE.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: RAINY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: FD
State/Local On Scene: FD
State Agency Number: NONE

NOTIFICATIONS BY NRC

DHS NOC (NOC)

02-JUL-11 02:29 (202)2828114
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02-JUL-11 02:29 (301)6693363
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02-JUL-11 02:29 (202)3661863
U.S. EPA VIII (MAIN OFFICE)
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FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
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02-JUL-11 02:29 (202)3660568
DOI/OEPC DENVER (MAIN OFFICE)
02-JUL-11 02:29 (303)4452500

ADDITIONAL INFORMATION

NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT #981503 ***

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U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

1200 New Jersey Ave., SE
Washington, DC 20590

JUL 05 2011

VIA CERTIFIED MAIL [7005 1160 0001 0075 9749] AND FAX TO: 713-656-8232

Mr. Gary Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street
Room 741-D
Houston, Texas 77002

Re: CPF No. 5-2011-5017H

Dear Mr. Pruessing:

Enclosed is a Corrective Action Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It requires ExxonMobil to take certain corrective actions with respect to the Silvertip hazardous liquid pipeline that failed on July 1, 2011 near Laurel, Montana. Service is being made by certified mail and facsimile. Your receipt of this Corrective Action Order constitutes service of that document under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon receipt.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Alan Mayberry, Deputy Associate Administrator for Field Operations, Pipeline Safety
Mr. Chris Hoidal, Director, Western Region, PHMSA

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
ExxonMobil Pipeline Company,	)	**CPF No. 5-2011-5017H**
Respondent.	)	

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112, to require ExxonMobil Pipeline Company (ExxonMobil or Respondent), to take the necessary corrective action to protect the public, property, and the environment from potential hazards associated with the recent failure on ExxonMobil's Silvertip hazardous liquid pipeline.

On July 1, 2011, a reportable accident occurred on the Silvertip line, resulting in the release of approximately 750-1000 barrels of crude oil into the Yellowstone River (the Failure). The Silvertip Pipeline is a 12-inch diameter pipeline approximately 69 miles in length that transports crude oil from the company's Silvertip Station near Elk Basin, Wyoming, to the ExxonMobil refinery in Billings, Montana. The cause of the Failure has not yet been determined. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the accident. The preliminary findings of the ongoing investigation are as follows.

Preliminary Findings

- The Silvertip Pipeline is a 12-inch diameter pipeline, approximately 69 miles in length, that transports crude oil from the Silvertip pump station near Elk Basin, Wyoming, to the ExxonMobil refinery in Billings, Montana.

- At approximately 10:40 p.m. MDT, on July 1, 2011, a failure occurred on Respondent's Silvertip Pipeline in Yellowstone County, Montana, resulting in the release of approximately 750-1000 barrels of crude oil into the Yellowstone River. The river flows eastward through the City of Billings and eventually discharges into the Missouri River. The Failure occurred between Mile Posts 20.7 and 21.0 in the vicinity of the city of Laurel, Montana (Failure Site). The Failure was reported to the National Response Center (NRC Report No. 981503) on July 2, 2011, at approximately 12:19 a.m. MDT.

- In response to the Failure, ExxonMobil shut down the pumps at Silvertip Station at approximately 10:47 p.m., MDT, on July 1, 2011. Respondent initially closed the Laurel block valve (1067) at approximately 10:57 p.m., reopened it at 11:07 p.m., and then finally closed it at 11:28 p.m. Finally, ExxonMobil closed the block valve located south of the Yellowstone River at approximately 11:36 p.m. on July 1, 2011. This operational timeline is based on control center timelines provided by ExxonMobil and converted to Mountain time by PHMSA staff.

- Various state and federal agencies responded to the scene including the U.S. Environmental Protection Agency. Spilled oil in the river has migrated as far downstream as Terry, Montana. Overflights conducted as recently as July 3, 2011 have observed oil deposits as far as 240 miles downstream in Terry, Montana.

- The cause of the failure is unknown and the investigation is still ongoing. The Failure Site is currently inaccessible due to high river flow in the Yellowstone River. According to the Billings Public Works Department, river flow at the time of the Failure was approximately 66,000 cubic feet per second.

- The accident did not cause any known injuries but approximately 140 people were initially evacuated.

- Water intakes for the City of Billings are located immediately downstream of the pipeline crossing and had to be temporarily shut down.

- Beginning in October 2010, following a public inquiry by the City of Laurel Public Works Department, PHMSA and the City of Laurel jointly reviewed river scour and bank erosion at the south bank of the Yellowstone River crossing. ExxonMobil agreed to perform a depth-of-cover survey, which was completed on December 1, 2010. ExxonMobil's completed depth-of-cover survey revealed at least five feet of cover at all measured points. In May 2011, following heavy flooding and in response to additional concerns by the City of Laurel, a PHMSA inspector began monitoring conditions of the pipeline crossing. On June 1, 2011, PHMSA contacted ExxonMobil to confirm the current depth of cover for this river crossing and ExxonMobil reported that there was at least 12 feet of cover.

- The section of the Silvertip Pipeline crossing the Yellowstone River in the vicinity of the Failure site was constructed in 1991; however, the original portions of the Silvertip Pipeline were primarily constructed between 1949-1954. The Failure site section consists of 12-inch diameter, 0.50 wall thickness, Grade B ERW seam pipe.

- The Silvertip Pipeline operates at an established maximum allowable operating pressure of 960 psig that was established by hydrotest in 1992.

- ExxonMobil performed an in-line inspection (ILI) of the Silvertip Pipeline in 2005 and 2009. Between June 6-10, 2011, PHMSA reviewed the raw ILI data and found no integrity-threatening pipe defects in pipe materials in the area of the Yellowstone River crossing.

Determination of Necessity for Corrective Action Order and Right to Hearing

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action, as appropriate. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233, a copy of which is enclosed.

Section 60112 and the regulations promulgated thereunder provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that failure to issue the Order expeditiously will likely result in serious harm to life, property, or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that continued operation of the Silvertip Pipeline without corrective measures would be hazardous to life, property, and the environment. Additionally, having considered the location of the Failure in a river crossing, the circumstances surrounding this failure including the current inaccessibility of the pipe, the uncertainties as to the cause of the failure, the proximity of the pipeline to navigable waterways, populated areas, and public water intake systems, and the hazardous nature of the product the pipeline transports, as well as the ongoing investigation to determine the cause of the failure, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in the likelihood of serious harm to life, property, or the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Western Region, PHMSA. If a hearing is requested, it will be held telephonically or in-person in Denver, Colorado or Washington, D.C.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken. In that event, Respondent will be notified of any additional measures required and amendment of this Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions

Pursuant to 49 U.S.C. § 60112, I hereby order ExxonMobil to immediately take the following corrective actions with respect to the Silvertip Pipeline from the Silvertip Pump Station to the ExxonMobil Billings refinery:

1. Prior to resuming operation of the pipeline, develop and submit a written re-start plan for prior approval of the Director, Western Region, OPS (Director), Pipeline and Hazardous Materials Safety Administration, 12300 W. Dakota Avenue, Suite 110, Lakewood, CO 80228.

2. The re-start plan must include procedures to safely return the remediated pipeline to service, evidence that all mandated actions required prior to restart are adequately completed, and a management of change plan that will ensure that all modifications are safely incorporated into Exxon Mobil's ongoing operations and maintenance procedures.

3. Prior to re-start, horizontally directionally drill (HDD) the Yellowstone River crossing of the Silvertip Pipeline to avoid future scour and external force damage. Use of any alternative crude oil pipeline delivery systems that are considered prior to completing the Yellowstone River HDD replacement must be submitted for evaluation and approval by the Director.

4. Prior to re-start, conduct a risk assessment pursuant to approval of the Director of all other major Silvertip Pipeline water crossings (greater than 100 feet from high water to high water) to determine if horizontal directionally drilled crossings should be installed at these areas. Each risk assessment must include a continuous depth of cover survey under the waterway and adjacent banks to justify the recommendations.

5. Prior to re-start, submit to the Director a contingency plan to operate and monitor the Silvertip Pipeline during flooding conditions, including enhanced patrolling and surveillance.

6. Prior to re-start, submit to the Director a revised oil spill response plan to reflect the events of this Failure.

7. Obtain written approval to resume operation of the line from the Director prior to resuming operation.

8. Within 60 days of obtaining access to the Failure Site, complete the failure investigation and determine mode of failure for the Yellowstone River crossing.

9. Within three months of replacing the Yellowstone crossing, perform another ILI inspection (metal loss and deformation) to ensure that there has been no other damage to the major river crossings for the Silvertip Pipeline.

10. Submit quarterly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first quarterly report is due on October 1, 2011. The Director may change the interval for the submission of these reports.

11. It is requested but not required that Respondent maintain documentation of the costs associated with implementation of this Corrective Action Order. Include in each monthly report submitted, the to-date total costs associated with: (1) preparation and revision of

procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

12. With respect to each submission that under this Order requires the approval of the Regional Director, the Director may: (a) approve, in whole or part, the submission; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove in whole or in part, the submission, directing that Respondent modify the submission, or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Respondent shall proceed to take all action required by the submission as approved or modified by the Director. If the Director disapproves all or any portion of the submission, Respondent must correct all deficiencies within the time specified by the Director, and resubmit it for approval.

The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted demonstrating good cause for an extension.

The actions required by this Corrective Action Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Part 195, under any other order issued to Respondent under authority of 49 U.S.C. § 60101 et seq., or under any other provision of Federal or State law.

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

In your correspondence on this matter, please refer to CPF No. 5-2011-5017H and for each document you submit, please provide a copy in electronic format whenever possible.

The terms and conditions of this Corrective Action Order are effective upon receipt.

JUL 05 2011

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

LETTER OF CONCERN

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 20, 2010

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, TX 77002

CPF 5-2010-5021C

Dear Mr. Pruessing:

On July 27 to 30, 2009, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected ExxonMobil's Silvertip Pipeline from the Silvertip Basin in Southern Montana to the ExxonMobil Refinery in Billings, Montana.

As a result of the inspection, the following item was identified as a concern, and if left uncorrected could lead to an unsafe condition or regulatory violation:

> The Silvertip Pipeline traverses Canyon Creek utilizing an elevated span just north of Interstate 90 between Laurel and Billings, Montana. The north bank of Canyon Creek at the location of the pipeline span appears to be eroding. In addition, the span only has one intermediate support while other pipelines suspended across the creek have two. Visual observation of the span indicates that it may be slightly sagging, thereby imposing bending stresses that may be beyond the original design.

We hope you will consider this area of concern as an opportunity to improve your existing pipeline safety program. If we can answer any questions or be of any help, please call us at (720) 963-3160.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2010-5021C.** Be advised that all material you submit in response to this letter is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 M. Petronis (#123899)

10-27-10A09:04 RCVD

ExxonMobil Pipeline Company
800 Bell Street, Room #603B
Houston, Texas 77002
(713) 656-0227 Telephone
(713) 656-8232 Facsimile

G.W. (Gary) Hartmann
Safety, Health And Environment Department
Manager

ExxonMobil Pipeline

September 13, 2010

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Material Safety Administration
12300 W. Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: CPF-5-2010- 5021C – Letter of Concern

Dear Mr. Hoidal

This is a response to the Letter of Concern issued on July 20, 2010 following the DOT Inspection of ExxonMobil Pipeline's Silvertip system in July 2009.

ExxonMobil strives to meet or exceed regulatory requirements. We appreciate receiving the leanings from this audit, and we are working to address them. There was one documented item of concern. Our response plan is documented below.

Item of Concern:

The Silvertip Pipeline traverses Canyon Creek utilizing an elevated span just north of Interstate 90 between Laurel and Billings Montana. The north bank of Canyon Creek at the location of the pipeline span appears to be eroding. In addition, the span only has one intermediate support while other pipelines suspended across the creek have two. Visual observation of the span indicates that it may be slightly sagging, thereby imposing bending stress that may be beyond the original design.

Response:

EMPCo has reviewed the span and identified no imminent risk. There is no history of loss of containment at the crossing. We completed another review of the most recent ILI pipe inspection output. The ILI analysis is one means of identifying significant deformations or ovality in the pipe, which could be symptoms of inadequate support. The July 7, 2009 ILI data did not show any such deformations. EMPCo's local operations team continues to monitor the soil erosion near the pipe support and along the north bank of the Canyon Creek crossing.

To further address PHMSA's concern, EMPCo is engaging an engineering firm to evaluate the Canyon Creek span. We have asked the firm to develop a tool to estimate pipe stress with the current configuration. We expect to have the results before the end of 2010.

Please contact Larry Hawthorne at: 903-879-0313 or myself with questions or concerns.

Sincerely,

Gary W. Hartmann

C – B. Clark
J. Rose
L. Hawthorne
J. Montgomery

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 20, 2010

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, TX 77002

CPF 5-2010-5022W

Dear Mr. Pruessing:

On July 27 to 30, 2009, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected ExxonMobil's Silvertip Pipeline from the Silvertip Basin in Southern Montana to the ExxonMobil Refinery in Billings, Montana.

As a result of the inspection, it appears that ExxonMobil has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§195.116 Valves.**

   Each valve installed in a pipeline system must comply with the following:
   (e) Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

At the Silvertip Station, the launcher bypass valves do not have a means for clearly indicating the position of the valves. ExxonMobil is required to have valves with a device that will indicate the position of the valves.

2. **§ 195.420 Valve maintenance.**

(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

During the field inspection of the Silvertip Pipeline, it was noted that Valve 1060 and Valve 1061 were leaking crude oil from the bonnets and/or stem packing as there was fresh crude oil on the soil immediately adjacent the valves. ExxonMobil submitted documentation a few weeks after the inspection to indicate that the valves had been replaced with new valves and that the crude oil had been cleaned up. ExxonMobil must ensure that each valve that is necessary for the safe operation of the Silvertip Pipeline is in good working condition at all times.

3. **§ 195.412 Inspection of rights-of-way and crossings under navigable waters.**

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.

During the field inspection of the Silvertip Pipeline, it was noted that the pipeline right-of-way on the south bank of the Clark's Fork of the Yellowstone River was covered by excessive vegetation, and it appeared that it was not visible by aerial patrols. ExxonMobil submitted documentation a few weeks after the inspection documenting that this area had been cleared of vegetation for effective aerial patrols. ExxonMobil must ensure that all portions of the pipeline right-of-way are cleared of vegetation to ensure that it is visible to aerial patrols. If removal of the vegetation along portions of the right-of-way is impractical, ExxonMobil must inspect those portions of the right of way by other means, i.e. walking or driving.

4. **§ 195.404 Maps and records.**

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c)(9) applies;
(vi) Rights-of-way; and
(vii) Safety devices to which §195.428 applies.
(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

(3) The maximum operating pressure of each pipeline.
(4) The diameter, grade, type, and nominal wall thickness of all pipe.

During the review of the maps and drawings of the Silvertip Pipeline, it was noted that the pipeline alignment drawings did not include information regarding the pipeline reconditioning project that was conducted near Rock Creek from 1999 to 2001, and the pipeline relocation that was performed along Interstate 90 near the Conoco Refinery in Billings several years ago. In addition, a mainline valve shown on the map near the town of Bridger appears to no longer exist. ExxonMobil must update the alignment drawings of the Silvertip Pipeline to ensure that the drawings accurately reflect the pipeline location and facilities installed as prescribed in section 195.404.

5. § 195.403 Emergency response training.

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are responsible to ensure compliance.

During the records review of the Silvertip Pipeline, it was noted that ExxonMobil relies solely on a self certification process to verify supervisor knowledge of emergency response procedures. ExxonMobil must develop a process that does not rely on self certification to ensure that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are responsible.

6. § 195.555 What are the qualifications for supervisors?

You must require and 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.

During the records review of the Silvertip Pipeline, it was noted that ExxonMobil relies solely on a self certification process to verify supervisor knowledge of corrosion control procedures. ExxonMobil must develop a process that does not rely on self certification to ensure that its supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.402(c)(3) for which they are responsible.

7. § 195.583 What must I do to monitor atmospheric corrosion control?

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.

During the records review of the Silvertip Pipeline, it was noted that ExxonMobil did not follow up on atmospheric corrosion issues that were identified during their three (3) year atmospheric corrosion surveys in a timely manner. ExxonMobil must provide protection against atmospheric corrosion identified on the Silvertip Pipeline in a timely manner.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violation. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item identified in this letter. Failure to do so will result in ExxonMobil being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2010-5022W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 M. Petronis (#123899)

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 8, 2007

Mr. John DuPre
Vice President – Operations, Northern
ExxonMobil Pipeline Company
3225 Gallows Road
Fairfax, VA 22037

SENT TO COMPLIANCE REGISTRY
Hardcopy__Electronically ✓
# of Copies 1 / Date 2/9/07

CPF 5-2007-5005M

Dear Mr. DuPre:

From June 20 to June 22, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected your procedures for Operations and Maintenance in Bridger, Montana.

As a result of the inspection, it appears that your written procedures are inadequate according to the requirements of §190.237:

1. **§195.222 Welders: Qualification of welders.**

   (b) Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has
   (1) Engaged in welding with that process; and
   (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.

ExxonMobil Pipeline Company's (EMPCo's) Pipeline Welding Manual procedures state that a welder may not weld with a particular welding process unless that welder has welded and had an acceptable NDT using that process within the previous 12 months. The correct time limitations must be incorporated.

2. **§195.228 Welds and welding inspection: Standards of acceptability.**

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (ibr, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

Nondestructive testing (NDT) procedures in EMPCo's DOT Liquids Manual reference 49 CFR Section 195.228 instead of referencing Section 9 of API 1104.

3. **§195.434 Signs.**

Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

EMPCo's DOT Liquids Manual signage procedure only calls for signage around breakout tanks, meters, valves, and other critical locations, but not specifically pump stations.

4. **§195.569 Do I have to examine exposed portions of buried pipelines?**

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate 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.

EMPCo's DOT Liquids Manual Exposed Pipe procedures for the examination of exposed portions of pipelines do not reference the form that EMPCo employees use when implementing this function.

5. **§195.573 What must I do to monitor external corrosion control?**

(b) Unprotected pipe. You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:
(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) 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.**

Though EMPCo's DOT Liquids Manual discusses the possibility that EMPCo may have bare pipe, corrosion procedures do not give guidance for cathodically protecting bare pipe.

Response to this Notice

If, after notice and opportunity for a hearing, your procedures are found to be inadequate, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237).

This letter serves as your notice of inadequate plans or procedures. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings.* Please refer to the Notice of Amendment portion of this document and note the response options. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue an Order Directing Amendment.

If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In your correspondence on this matter, please refer to **CPF 5-2007-5005M** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

cc: PHP-60 Compliance Registry
PHP-500 (G. Davis, #116697)

ExxonMobil Pipeline Company
800 Bell Street, Room #603B
Houston, Texas 77002
(713) 656-0227 Telephone
(713) 656-8232 Facsimile

K. G. (Kevan) McCrae
Manager
Safety, Health And Environment Department

SENT TO COMPLIANCE REGISTRY
Hardcopy ✓ Electronically ___
# of Copies 3 / Date 4/10/07

ExxonMobil Pipeline

March 22, 2007

RECEIVED
APR 0 2 2007

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 West Dalota Avenue, Suite 110
Lakewood, Colorado 80228-2585

Re: Notice of Amendment
PHMSA - File Number CPF 5-2007-5005M

Dear Mr. Hoidal:

A representative of the Western Region, Pipeline and Hazardous Materials Safety Administration (PHMSA) conducted a pipeline safety inspection of ExxonMobil Pipeline Company's (EMPCo) Silvertip to Billings, Montana pipeline system between June 20, 2006 and June 22, 2006.

On February 27, 2007 EMPCo received a Notice of Amendment for alleged inadequate written procedures noted during the inspection. This letter serves as EMPCo's formal response to the Notice. This letter is being issued to PHMSA within the required 30 days from receipt, and is therefore timely.

Due to a change in EMPCo management please address any future correspondence on this matter to:

Mr. Jimmie James
Northern Operations Manager
3225 Gallows Road, Room 5B2134
Fairfax, Virginia 22037

The Notice identified five instances of possible inadequate plans or procedures. The allegations are addressed in detail below, followed by EMPCo's response.

1. § 195.222. Welders: Qualification of welders

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has--

(1) Engaged in welding with that process; and

(2) Had one weld tested and found acceptable under section 9 of API 1104.

PHMSA Allegation:
ExxonMobil Pipeline Company's (EMPCo) Pipeline Welding Manual procedures state that a welder may not weld with a particular welding process unless that welder has welded and had an acceptable NDT using that process within the previous 12 months. The correct time limitations must be incorporated.

EMPCo Response:
EMPCo does not dispute this finding. As noted in an e-mail sent to PHMSA inspector, Mr. Jerry Davis, October 2, 2006, (Attachment 1) the EMPCo Pipeline Welding Manual was corrected to incorporate the six month limitation. Page 22 of the Pipeline Welding Manual now states:

> 3.2.5. Welder Requalification
> 1) Requalification Time Period (Pipeline Welders)
> a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 6 **months** pipeline work.

2. § 195.228. Welds and welding inspection: Standards of acceptability

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (incorporated by reference, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

PHMSA Allegation:
Nondestructive testing (NDT) procedures in EMPCo's DOT Liquids Manual reference 49CFR Section 195.228 instead of referencing Section 9 of API 1104.

EMPCo Response:
EMPCo disagrees that this procedure is inadequate. By referencing 49CFR 195.228 in its DOT Liquids Manual, Section 9 of API 1104 is already referenced in EMPCo's procedures. The EMPCo's DOT Liquids Manual was thoroughly reviewed and found to be in compliance with all applicable requirements by a centralized DOT review team, November 4 - 7, 2002. This was a focused and comprehensive audit which did not result in a recommended change to this section of EMPCo's procedures.

Additionally, EMPCo's DOT Liquids Manual is scheduled for another DOT Procedural Manual review during the week of April 2, 2007. This allegation could have a broad impact on the structure of EMPCo's DOT Liquids Manual, thus we feel it is more appropriate to discuss this issue during the DOT centralized review.

3. § 195.434. Signs

Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

PHMSA Allegation:
EMPCo's DOT Liquids Manual signage procedure only calls for signage around breakout tanks, meters, valves, and other critical locations, but not specifically pump stations.

EMPCo Response:
EMPCo disagrees that this procedure is inadequate. During the inspection it was explained to the Inspector that "Critical Locations" in a pipeline context would necessarily include pump stations. All field pump locations had the appropriate signage. Since the addition of "pump station" was a relatively easy addition, the change was made to EMPCo's DOT Liquids Manual during the next revision. This was communicated to the inspector in an e-mail sent to the PHMSA inspector October 2, 2006, (Attachment 1).

EMPCo's DOT Liquids Manual signage procedure now states:

(5) Emergency Notification
(A) Install station emergency information signs at each meter station, regulator station, **pump station**, valve site, and other critical locations where considered appropriate, Company's Name and Emergency Telephone Number shall be correctly identified.

4. § 195.569. Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under § 195.585, you must investigate 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.

PHMSA Allegation:
EMPCo's DOT Liquids Manual, Exposed Pipe procedures for the examination of exposed portions of pipelines does not reference the form that EMPCo employees use when implementing this function.

EMPCo Response:
EMPCO disagrees that the procedure is inadequate. At the time of the audit EMPCo's DOT Liquids Manual specified that "Condition of the coating and the extent of external corrosion must be recorded." The fact that a particular form number was not specified does not make the procedure inadequate as 49 CFR 195 does not specifically require form numbers be listed. EMPCo did however agree that the inclusion of the form number would add value to the procedure, and it has

been added to The DOT Liquids Manual. This was communicated to the inspector in an e-mail sent to the PHMSA inspector October 2, 2006, (Attachment 1). The manual now reads:

> **A. Exposed Pipe**
> Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe, and complete **Form PL-751**. When there is evidence of *significant corrosion*, the person responsible for corrosion matters must be notified. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

5. § 195.573. What must I do to monitor external corrosion control?

(b) Unprotected pipe. You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

(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) 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.

PHMSA Allegation:
Though EMPCo's DOT Liquids Manual discusses the possibility that EMPCo may have bare pipe, corrosion procedures do not give guidance for cathodically protecting bare pipe.

EMPCo Response:
EMPCO disagrees that the procedure is inadequate. EMPCo explained to the inspector that there is no unprotected pipe in the audit focus area, (EMPCo's Silvertip to Billings pipeline) and that EMPCo's Cathodic Protection program included in EMPCo's Facilities Inspection and Maintenance Management System (FIMMS) states that:

> **A. PLANNING**
> EMPCo and government regulations set survey requirements and

frequency. EMPCo's intent is to provide cathodic protection to all regulated assets.

We have attempted to provide a detailed response to each allegation of inadequate procedures in the event that these matters can be resolved outside of a hearing. However, if a solution to this matter cannot be agreed upon based on the information provided in this letter, we reserve our right to a hearing on all issues outlined in the Notice, at which time we would be represented by counsel.

Sincerely,



Attachments

10/02/06 e-mail document

ATTACHMENT 1

Montana DOT Audit June 2006
Findings

195.214 Welding procedures.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code (ibr, see §195.3) . The quality of the test welds used to qualify the welding procedure shall be determined by destructive testing.

(b) 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.

FINDING: EMPCo's Liquid Manual should cite the proper version of the correct standard (API 1104 in this case) and not reference the regulation (49CFR 195)

RESPONSE: EMPCo's Liquid Manual was reviewed and approved by a team of inspectors in 2002, the manual will be eligible for review again next year in 2007. EMPCo would like to address this issue during the next O&M Manual review.

195.222 Welders: Qualification of welders.

(a) Each welder must be qualified in accordance with section 6 of API 1104 (ibr, *see* §195.3) or section IX of the ASME Boiler and Pressure Vessel Code, (ibr, *see* §195.3) except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not re-qualify under that earlier edition.

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has—

(1) Engaged in welding with that process; and

(2) Had one welded tested and found acceptable under section 9 of API 1104 (ibr, *see* §195.3).

FINDING: EMPCo's Welding manual states that welders on liquid lines must requalify at intervals not exceeding 12 months.

> **3.2.5. Welder Requalification**
> 1) Requalification Time Period (Pipeline Welders)
> a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 12 months for liquid pipeline work and 6 months for gas pipeline work.

RESPONSE: EMPCo's Welding Manual has been revised to state that welders on liquid lines must requalify at intervals not exceeding 6 months.

> **3.2.5. Welder Requalification**
>
> 1) Requalification Time Period (Pipeline Welders)

a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 6months pipeline work.

§ 195.234 Welds: Nondestructive testing.

FINDING: EMPCo's Liquid Manual references 195.228 when it should reference the correct standard (API 1104 in this case).

RESPONSE: EMPCo's Liquid Manual was reviewed and approved by a team of inspectors in 2002, the manual will be eligible for review again next year in 2007. EMPCo would like to address this issue during the next O&M Manual review.

§ 195.434 Signs.

Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

EMPCo's Liquid Manual states:

(5) Emergency Notification

(A) Install station emergency information signs at each meter station, regulator station, valve site, and other critical locations where considered appropriate, Company's Name and Emergency Telephone Number shall be correctly identified.

FINDING: Need to revise EMPCo's Liquid Manual to specifically include "pumping stations".

RESPONSE: EMPCo's Liquid Manual will been revised to read:

(5) Emergency Notification

(A) Install station emergency information signs at each meter station, regulator station, valve site, **pump station**, and other critical locations where considered appropriate, Company's Name and Emergency Telephone Number shall be correctly identified.

§ 195.569 Do I have to examine exposed portions of buried pipelines?

A. Exposed Pipe

Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe. When there is evidence of significant corrosion, the person

responsible for corrosion matters must be notified. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

FINDING: EMPCo's Liquids Manual needs to state that whenever the pipeline is exposed a PL-751 form should be filled out.

RESPONSE: EMPCo's Liquids Manual will been revised to read:
A. Exposed Pipe
Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe and complete form PL-751. When there is evidence of significant corrosion, the person responsible for corrosion matters must be notified. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

§ 195.573 What must I do to monitor external corrosion control?

(b) *Unprotected pipe.* You must reevaluate your unprotected buried or submerged pipe and catholically protect the pipe in areas in which active corrosion is found, as follows:

(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) For the period in the first column, the second column prescribes the frequency of evaluation

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.

FINDING: EMPCo's Facilities Inspection and Maintenance Management System (FIMMS) Manual does not have a procedure for unprotected pipe. Need to revise the FIMMS to include a procedure for monitoring unprotected pipe or include a statement that states EMPCo does not intentionally operate unprotected pipe.

RESPONSE: A statement has been added to EMPCo's FIMMS Manual that reads, "Regarding unprotected pipe, ExxonMobil Pipeline Company's intent is to provide cathodic protection to all regulated assets. 195.573(b)"

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

FINDING: Currently EMPCo's Reference Library shows the date of the last review. Need to show last two review dates, or provide another method such as "Records of Revision/Review for manuals referenced in EMPCo's Liquid Manual.

RESPONSE: EMPCo lists the latest review date on the "Reference Library" section of our intranet site. Dates from earlier reviews can be found in the "Record of Revision" section of each manual requiring review.

§ 195.214 Welding procedures.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code (ibr, see §195.3) . The quality of the test welds used to qualify the welding procedure shall be determined by destructive testing.

(b) 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.

FINDING: EMPCo will provide a Procedure Qualification Report (PQR) for welding procedure
18-87-31 (Applying End Fillet Welds on Stopples, Sleeves, and Weld + Ends Under Flow Conditions)

RESPONSE: PQR's included with this sending.

§ 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart 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 Standard RP0169–96 (incorporated by reference, see §195.3).

FINDING: EMPCo will provide a graph plotting data form the 2005 annual corrosion survey on the same graph whit data from the 2004, 2003, and 2002 surveys.

RESPONSE: Graph is included with this sending.

Facsimile

ExxonMobil Pipeline

Date:03/27/07

Subject: Notice of Amendment PHMSA #CPF 5-2007-5005M

To: Mr Chris Hoidal
PHMSA Director
Western Region

Pages: (Including Cover)

Telephone: (720) 963-3160
Facsimile: (720) 963-3161

☐ **Urgent**
☐ **Please Comment / Reply**

From: Thad Massengale
EMPCo

☐ **FYI / Please Recycle**
Copy To:

Telephone: (713) 656-2258
Facsimile: (713) 656-8232

Message: Mr. Hoidal the following is response to PHMSA's Notice of Amendment #CPF 5-2007-5005M pertaining to a Liquid Pipeline Inspection conducted on EMPCo's Silvertip to Billings Pipeline in June 2006. The NOA was sent to Mr. John Y. DuPre. Mr. DuPre has moved on to other assignments, please send future correspondence on this matter to Mr. Jimmie James, address is included in the response. Thank you.

The information contained in this facsimile may be confidential and may also contain privileged attorney-client information or work product. The information is intended only for the use of the individual or entity to which it is addressed. If you are not the intended recipient, or the employee or agent responsible to deliver it to the intended recipient, you are hereby notified that any use, dissemination, distribution, or

1. **§ 195.222. Welders: Qualification of welders**

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has--

(1) Engaged in welding with that process; and

(2) Had one weld tested and found acceptable under section 9 of API 1104.

PHMSA Allegation:
ExxonMobil Pipeline Company's (EMPCo) Pipeline Welding Manual procedures state that a welder may not weld with a particular welding process unless that welder has welded and had an acceptable NDT using that process within the previous 12 months. The correct time limitations must be incorporated.

EMPCo Response:
EMPCo does not dispute this finding. As noted in an e-mail sent to PHMSA inspector, Mr. Jerry Davis, October 2, 2006, (Attachment 1) the EMPCo Pipeline Welding Manual was corrected to incorporate the six month limitation. Page 22 of the Pipeline Welding Manual now states:

> 3.2.5. Welder Requalification
> 1) Requalification Time Period (Pipeline Welders)
> a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 6 months pipeline work.

2. § 195.228. Welds and welding inspection: Standards of acceptability

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (incorporated by reference, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

PHMSA Allegation:
Nondestructive testing (NDT) procedures in EMPCo's DOT Liquids Manual reference 49CFR Section 195.228 instead of referencing Section 9 of API 1104.

EMPCo Response:
EMPCo disagrees that this procedure is inadequate. By referencing 49CFR 195.228 in its DOT Liquids Manual, Section 9 of API 1104 is already referenced in EMPCo's procedures. The EMPCo's DOT Liquids Manual was thoroughly reviewed and found to be in compliance with all applicable requirements by a centralized DOT review team, November 4 - 7, 2002. This was a focused and comprehensive audit which did not result in a recommended change to this section of EMPCo's procedures.

Additionally, EMPCo's DOT Liquids Manual is scheduled for another DOT Procedural Manual review during the week of April 2, 2007. This allegation could have a broad impact on the structure of EMPCo's DOT Liquids Manual, thus we feel it is more appropriate to discuss this issue during the DOT centralized review.

04-24-08A11:39 RCVD

ExxonMobil Pipeline Company
800 Bell Street, Room #603B
Houston, Texas 77002
(713) 656-0227 Telephone
(713) 656-8232 Facsimile

K. G. (Kevan) McCrae
Manager
Safety, Health And Environment Department

ExxonMobil
Pipeline

SENT TO COMPLIANCE REGISTRY
Hardcopy__ Electronically ✓
# of Copies 1 / Date 4/24/08

April 18, 2008

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 West Dalota Avenue, Suite 110
Lakewood, Colorado 80228-2585

Re: Notice of Amendment
PHMSA - File Number CPF 5-2007-5005M

Dear Mr. Hoidal:

A representative of the Western Region, Pipeline and Hazardous Materials Safety Administration (PHMSA) conducted a pipeline safety inspection of ExxonMobil Pipeline Company's (EMPCo) Silvertip to Billings, Montana pipeline system between June 20, 2006 and June 22, 2006.

On February 27, 2007 EMPCo received a Notice of Amendment (Notice) for alleged inadequate written procedures noted during the inspection. A response to the Notice was provided on March 22, 2007, that response was issued within 30 days of receipt of the Notice and was therefore timely.

EMPCo would like to provide additional information in order to close the five allegations contained in the Notice.

1. § 195.222. Welders: Qualification of welders

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has--

(1) Engaged in welding with that process; and

(2) Had one weld tested and found acceptable under section 9 of API 1104.

PHMSA Allegation:
ExxonMobil Pipeline Company's (EMPCo) Pipeline Welding Manual procedures state that a welder may not weld with a particular welding process unless that welder has welded and had an acceptable NDT using that process within the previous 12 months. The correct time limitations must be incorporated.

EMPCo Response:
EMPCo has corrected the EMPCo Pipeline Welding Manual to incorporate the six month limitation. Page 22 of the Pipeline Welding Manual now states:

> 3.2.5. Welder Requalification
> 1) Requalification Time Period (Pipeline Welders)
> a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 6 months pipeline work.

2. § 195.228. Welds and welding inspection: Standards of acceptability

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (incorporated by reference, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

PHMSA Allegation:
Nondestructive testing (NDT) procedures in EMPCo's DOT Liquids Manual reference 49CFR Section 195.228 instead of referencing Section 9 of API 1104.

EMPCo Response:
EMPCo has amended its DOT Liquids Manual to read:

195.234. Welds: Nondestructive Testing
PROCEDURE:
(c) Weld inspection procedures for compliance with 195.228 should be consistent with API 1104, Section 9. **For additional information, refer to ExxonMobil Pipeline Repair and Modification Manual-Section 6, and Welding Manual.**

3. § 195.434. Signs

Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

PHMSA Allegation:
EMPCo's DOT Liquids Manual signage procedure only calls for signage around breakout tanks, meters, valves, and other critical locations, but not specifically pump stations.

EMPCo Response:
EMPCo's DOT Liquids Manual signage procedure now states:

(5) Emergency Notification
(A) Install station emergency information signs at each meter station, regulator station, pump station, valve site, and other critical locations where considered appropriate, Company's Name and Emergency Telephone Number shall be correctly identified.

4. § 195.569. Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under § 195.585, you must investigate 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.

PHMSA Allegation:
EMPCo's DOT Liquids Manual, Exposed Pipe procedures for the examination of exposed portions of pipelines does not reference the form that EMPCo employees use when implementing this function.

EMPCo Response:
EMPCO has amended its DOT Liquids Manual to read:

A. Exposed Pipe
Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe, and complete Form PL-751. When there is evidence of significant corrosion, the person responsible for corrosion matters must be notified. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

5. § 195.573. What must I do to monitor external corrosion control?

(b) Unprotected pipe. You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

(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) 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.

PHMSA Allegation:
Though EMPCo's DOT Liquids Manual discusses the possibility that EMPCo may have bare pipe, corrosion procedures do not give guidance for cathodically protecting bare pipe.

EMPCo Response:
Changes to EMPCo's Cathodic Protection program included in EMPCo's Facilities Inspection and Maintenance Management System (FIMMS) will include a statement that will apply the procedures listed in the program to be applicable to both bare and coated pipe.

We have attempted to provide a detailed response to each allegation of inadequate procedures in the event that these matters can be resolved outside of a hearing. However, if a solution to this matter cannot be agreed upon based on the information provided in this letter, we reserve our right to a hearing on all issues outlined in the Notice, at which time we would be represented by counsel. Please confirm whether the responses provided above satisfactorily addresses the referenced Notice of Amendment. If you have additional questions, please contact Thad Massengale at (713)-656-2258. Thank you.

Sincerely,

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

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 20, 2008

Mr. John DuPre
Vice President – Operations, Northern
ExxonMobil Pipeline Company
3225 Gallows Road
Fairfax, VA 22037

CPF 5-2007-5005M

Dear Mr. DuPre:

On June 20 through June 22, 2006, a representative from the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to chapter 601 of 49 United States Code, conducted an on-site pipeline safety inspection of ExxonMobil Pipeline Company's (EMPCo) procedures in Bridger, Montana. As a result of the inspection, EMPCo was issued a Notice of Amendment on February 8, 2007, which proposed amendment of your procedures.

EMPCo submitted its amended procedures in written response on March 22, 2007 and April 18, 2008 and by email on May 14, 2008. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

Jeffrey D. Gilliam for C.H.

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 G. Davis (#116697)

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

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 11, 2008

Mr. Patrick Doolan
Vice President
ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

CPF 4-2007-5030M

Dear Mr. Doolan:

During April 9-13, 2007; April 23-27, 2007; and May 7, 2007 representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected ExxonMobil Pipeline Company (EMPCo) procedures for Hazardous Liquid Integrity Management in Houston, TX.

As a result of the inspection, EMPCo was issued a Notice of Amendment on August 2, 2007.

EMPCo submitted its amended procedures on October 31, 2007. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

Pat Doolan
Vice President
Southern Operations

ExxonMobil
Pipeline

October 31, 2007

VIA FACSIMILE (713-272-2859) AND
CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Notice of Amendment CPF No. 4-2007-5030M

Dear Mr. Seeley:

Representatives of the Office of Pipeline Safety conducted a comprehensive inspection of ExxonMobil Pipeline Company's (EMPCo) Integrity Management Program (IMP) during April 9-13, 2007; April 23-27, 2007; and May 7, 2007. Pursuant to this inspection, on August 7, 2007, EMPCo received a Notice of Amendment (NOA) and a Warning Letter from the Pipeline and Hazardous Materials Safety Administration (PHMSA). This letter is EMPCo's final response to the NOA. All items identified by the warning letter have been previously resolved.

The NOA identified one (1) area for amendment. This item is outlined in detail below, followed by EMPCo's completed actions to address the recommended improvement.

Item 1.
§195.452 Pipeline integrity management in high consequence areas
(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
(5) Assessment Methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
(iii) External corrosion direct assessment in accordance with §195.588

§195.588 What standards apply to direct assessment?
(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section 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.

(b) The requirements for performing external corrosion direct assessment (ECDA) are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include -

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment

A. *EMPCo must modify their ECDA procedures regarding indication severity classification in the ECDA Plan Table A3.3 which does not appear to be as conservative as NACE RP-0502-2002 Table 3. NACE RP 0502-2002 table 3 gives example severity criteria for several indirect inspection methods.*
B. *EMPCo must modify their ECDA procedures to ensure that more restrictive criteria in addition to those required by NACE RP-0502-2002 are applied when conducting ECDA direct examination for the first time on a pipeline segment per §195.588. EMPCo has indicated that additional excavations will be conducted when conducting ECDA direct examinations for the first time on a pipeline segment; however, these additional excavations are a requirement of NACE RP-0502-2002 and, therefore, the IMP rule. As such, the additional excavations do not represent "more restrictive criteria" as described in §195.588.*

EMPCo Action:
EMPCo has completed modification of the ECDA process as noted above. The revised version of the Facility Integrity Management System (FIMMS) ECDA document is attached. Specifically, EMPCo has completed the following revisions:

- Modified the ECDA process to include indication severity classifications which are as conservative as NACE RP-0502-2002 Table 3. See Section A3.2.3 of the attached procedures.
- Modified the ECDA procedures to apply criteria more restrictive than that required by NACE RP-0502-2002 for first time ECDA's. See Section A3.3.2 of the attached procedures.

If you have any questions about the information presented in this letter, or desire additional information, please contact Johnita D. Jones at 512-306-7981 or Steve Koetting at 713-656-2070.

We look forward to hearing back from PHMSA regarding final closure of this NOA item.

Patrick T Doolan
Operations Manager
ExxonMobil Pipeline Company

I. SCOPE AND OBJECTIVE

Purpose:

The focus of the DA approach described in this document is to identify more probable locations of time dependant, time independent, and stable integrity threats.

This document describes the minimum requirements for ExxonMobil Pipeline Company's (EMPCo) DA Inspection Program. It provides guidelines for the proper selection of techniques used for DA inspections of pipelines. These techniques are utilized to detect potential integrity threats without the need to remove the pipeline from normal operating service.

The DA Inspection Program provides the minimum requirements for compliance with applicable Department of Transportation (DOT) and State Regulations and OIMS requirements, and to provide information to support risk assessments and risk management decisions.

This document describes the process of performing External Corrosion Direct Assessment (ECDA) to buried pipeline segments. This procedure had been developed in accordance with the NACE RP0502-2002: Pipeline External Corrosion Direct Assessment Methodology.

Scope:

Direct Assessment (DA) is a process through which an operator may be able to assess the integrity of a pipeline. This process integrates a knowledge of the physical characteristics and operating history of a pipeline with the results of diagnostic and direct measurements performed on the pipeline. The process is intended to improve pipeline integrity and safety by assessing and reducing the impact of external corrosion (EC) and third party damage (TPD). By identifying and addressing EC and TPD activity, ECDA seeks to proactively prevent external corrosion defects from growing to a size that affects the structural integrity of the pipeline segments, and proactively

identify TPD defects by identifying locations where TPD has occurred and associated coating has been damaged .

DA Process:

The DA methodology is a four-step process that requires the integration of data from multiple indirect field inspections and from direct pipe surface examinations with the pipe's physical characteristics and operating history. The four steps of the process are:

1. Pre-Assessment
2. Indirect Inspection
3. Direct Examination
4. Post-Assessment

Each step of the DA Process is covered in detail below.

Pre-Assessment:

The Pre-Assessment step collects historic and current data to determine whether DA is feasible, what indirect inspection tools are appropriate, and defines DA regions. The types of data to be collected are available on alignment sheets, on maintenance records, in annual corrosion surveys, on encroachment and foreign line crossing reports, on hydrostatic pressure test records, entered in a Geographic Information System (GIS), in job or projects records in local and centralized record storage, and in the memories of personnel who have worked on and maintained pipeline facilities over the years. Past history of any TPD events on the applicable pipeline segment(s) and similar segments must be divulged to the DA Service Provider during the Pre-Assessment phase of a DA project such that adequate analysis and inspection for TPD can be planned for Indirect Inspections and Direct Examinations. **See Attachment 3: Execution, Pre-Assessment**

Indirect Inspection:

Indirect inspection covers above ground inspections to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity

may have or may be occurring. Normally, two or more indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability under the wide variety of conditions that may be encountered along a pipeline right-of-way. **See Attachment 3: Execution, Indirect Inspection**

Direct Examination:

The Direct Examination step includes analyses of indirect inspection data to select sites for excavations and pipe surface evaluations. The data from the direct examinations are combined with prior data (i.e. from pre-assessment and indirect steps) to identify and assess the impact of external corrosion or TPD on the pipeline. **See Attachment 3: Execution, Direct Examination**

Post-Assessment:

The Post-Assessment step covers analyses of data collected from the previous three steps to assess the effectiveness of the DA process and determine reassessment intervals. **See Attachment 3: Execution, Post-Assessment**

Integration of Results into IMP Processes

When the DA inspections are completed and a final report is received from the DA service provider, results from the DA Integrity Assessment are integrated with all other integrity data, exactly the same as other integrity assessments such as hydrostatic pressure test and In-Line Inspection within EMPCo's Integrity Management Program. The results of Data Integration is used to drive additional Preventive and Mitigative (P&M) processes for each pipeline segment. Special attention to Third Party Damage threats must be considered when analyzing data from DA projects and additional P&M activities must be considered to mitigate any TPD threats on lines assessed with Direct Assessment. If TPD is identified as a significant threat to the pipeline segment, additional preventive measures must be implemented by the operator and measures are to be taken to monitor the effectiveness of those additional preventive measures.

II. RESOURCES AND RESPONSIBILITY	**Risk and Integrity Manager**: Responsibility to assure that the Direct Assessments are implemented effectively. Is responsible for seeking regulatory approval to use DA for selected pipeline segments. Approves process and program exceptions. **Risk and Integrity Adviser:** Responsible for maintaining assessment schedule including integrity assessment method. Collects data on effectiveness of program. **Field Steward(s)**: Designated Local Operations Personnel and Field Engineers who are responsible for executing DA Project Field Inspections and locating records and personnel with knowledge to be gathered during pre-assessments. **Qualified Individuals:** Risk and Integrity Specialists and selected Field Engineers who are responsible for reviewing the results of integrity assessments and preparing repair and preventive and maintenance plans from data collected during the DA process. **Engineering Specialists**: Pipeline Integrity Specialist, Risk Assessment Specialist and others who set acceptability of DA process procedures and specifications. The Pipeline Integrity Specialist serves as Program Steward and the Program Expert for the DA Process and must be consulted for all changes to this process and for all program exceptions. **Pipeline Safety Advisor:** Responsible for providing formal notifications to the applicable State Regulatory Agencies for approval to use the Direct Assessment process for Integrity Assessment of pipeline segments in accordance with Integrity Management Program (IMP) and High Consequence Areas (HCA's) regulations. **Databases:** HCA Database, Geographic Information System (GeoIS) Databases, Central Information Center (CIC), CPDM Corrosion Database

III. PROCESSES AND PROCEDURES	A. PLANNING
	DA is addressed in DOT Regulation Title 49 CFR Part 195.452, *Pipeline Integrity Management in High Consequence Areas* and in DOT Regulation Title 49 Part 192 Subpart O, *Pipeline Integrity Management.* These sections allow Direct Assessment under the section of the liquid pipeline regulation 195.452 (c) (1) (i) (C) External Corrosion Direct Assessment in accordance with 195.588 (requires more stringent criteria than NACE RP 1502-2002: External Corrosion Direct Assessment), with appropriate notification and approvals by State regulators (as applicable), and in section 192.923 in the gas pipeline regulation. A DA program that exceeds the requirements of NACE Standard Recommended 0502-2002, *Pipeline External Corrosion Direct Assessment* can be used in lieu of the DOT hydrotest or In-Line Inspection requirements, and is an excellent option if a pipeline cannot tolerate any sizable amount of downtime, as would be the case of a hydrotest, and is not smart pig compatible (and cannot be feasibly modified to become smart pig compatible) such as a dual diameter line or very short pipeline segment. DA is not appropriate for all pipeline segments. The process is self-validating and so continually verifies that the DA process is applicable and is an appropriate integrity assessment to the particular pipeline segment. At this time EMPCo has only adopted DA to apply to a limited number of pipeline segments. The pipeline segments are limited to those with viable integrity threats of External Corrosion and TPD. Pipeline segments discovered to have susceptibility to significant internal corrosion, long seam failure, or stress corrosion cracking must be eliminated from consideration as ECDA candidates until such time as other processes are available to evaluate those threats. Similarly, pipeline segments that have areas of limited accessibility where the indirect techniques cannot suitably inspect nor the direct examination techniques provide sufficient data may not be appropriate candidates for DA. Finally, since DA is heavily data driven, segments with limited available historical data should be excepted from the DA process. It should be noted that a short pipeline segment can be 100% directly examined using the DA process as a valid integrity assessment without using Indirect Inspection techniques.

B. Execution

See Attachment 1: Available Indirect Inspection Techniques

See Attachment 2: Available Direct Examination Techniques

See Attachment 3: Execution

C. Data Management & Integration

The DA process is heavily data dependent. The pre-assessment process results are normally available within three to six weeks, depending on the availability of information. The indirect surveys are dependent on line access. The direct surveys are dependent on the ability to complete excavations on a pipeline. The detailed final analysis of the data usually takes from one to two months to get results following the completion of the direct surveys. DA results are maintained in corporate databases to be further integrated into a risk analysis and/or GIS platforms. Hard copies of the DA results are to be maintained at the respective field office and in the CIC.

D. Corrective Actions

After the initial program results are obtained and reviewed following the completion of the DA study, any major anomalies can be investigated with further investigative excavation and corrected according to the highest risk prioritization. See EMPCo Integrity Management Program Manual

IV. MEASUREMENT AND VERIFICATIONS	**Measurement:** • # of Segments and HCA Mileage assessed with DA • # of leaks after DA, in and outside of HCA's • # of repairs made during and as a result of DA **Verification:** • # of anomalies ID'd where ILI or Hydro methods are incapable of identifying • # of other integrity issues addresses as a result of DA • # of assessment method changes made due to identification of segment incompatibility with DA process.
V. FEEDBACK AND CONTINUOUS IMPROVEMENT	Periodically, the Program Steward will meet with Engineering's Pipeline Integrity Specialist and designated others as needed, to conduct a formal self-assessment of the DA Program. This internal self-assessment will review processes and results, technical aspects and analyze any audits or other assessments performed since the last self assessment. Results of the formal internal assessment will also be reviewed with the Integrity Management Team along with the proposed plans for any ongoing program improvements and refinement.
VI. REFERENCE MATERIALS	The following documents were used in writing this document: • Department of Transportation Regulations Title 49 Part 195 • Code of Federal Regulations 49CFR195.452, *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas.* • Code of Federal Regulations 49CFR192 - *Subpart O: Pipeline Integrity Management* • NACE Standard RP0502-2002, *Pipeline External Corrosion Direct Assessment Methodology* • ASME B31.8S: *Managing System Integrity of Gas Pipelines*

	• API 1160: *Managing System Integrity for Hazardous Liquid Pipelines* • EMPCo OIMS Manual • EMPCo In-Line Inspection FIMMS Document • Vendor Data

Attachment 1: AVAILABLE INDIRECT INSPECTION TECHNIQUES Technical Background

Direct Assessment utilizes a number of survey techniques to determine the integrity state of a pipeline. Listed below is a description of some of the more common methods presently used to conduct indirect surveys.

A1.0: Close Interval Survey (CIS)

Close interval surveys, which are also referred to as pipe to soil and potential gradient surveys, are applicable to all buried pipelines with an earthen cover. Close interval surveys are used to measure the potential difference between the pipe and the earth. Close interval surveys are typically used to determine cathodic protection (CP) levels, shorts to other structures, and stray current areas. There are various types of close interval surveys, including on/off potential surveys, depolarized potential surveys and on potential surveys. These survey techniques are limited in their ability to detect small coating holidays and are difficult to use in areas that are paved over. See also EMPCo FIMMS Close Interval Survey procedures.

A1.1: Method, Equipment and Reporting:

- Structure-to-electrolyte measurements shall be taken at intervals specified by the operator using a calibrated copper-copper-sulfate reference half-cell and high resistance direct current (DC) voltmeter.
- The condition of the reference cell must be monitored to ensure the accuracy of the voltage measurements. The plastic tube shall be kept full of saturated solution with some extra copper crystals to ensure the solution remains saturated. The plug must be inspected periodically to ensure it is moist and clean. If the cell leaks, cracks, or other damage is observed, the cell shall be replaced.
- The reference half-cell shall be positioned on the surface directly above the pipeline to be investigated. If this is not possible, place the reference cell off to the side of the structure where the nearest soil/earth exists. If this distance exceeds five (5) feet, a ½ inch boring (bar hole) with repairs shall be made at a depth necessary to obtain satisfactory contact with soil/earth to provide accurate and meaningful voltage measurements directly over the facility.
- If the soil is dry, moisten each test point, but do not saturate with water.
- If it is necessary to take voltage readings on a concrete surface, place a clean wet cloth on the concrete and then place the reference cell on the cloth.
- Voltage readings on macadam, asphalt (black top) surface shall never be taken unless a ½ inch boring is made to contact soil beneath the macadam surface.
- If one or more segments of pipe are protected by an impressed current rectifier system, the contractor shall have the capability to simultaneously interrupt all rectifier systems to ensure proper on/off voltage measurements are retrieved.
- ExxonMobil shall provide the contractor with location and acceptable limits of operation for all impressed current rectifier systems prior to test. The contractor shall read voltage and current outputs before beginning test to ensure proper operational output. Should any of the system outputs vary more than +/-25%, the contractor shall contact ExxonMobil's representative to investigate and correct before proceeding with the test.
- The contractor is required to retrieve static voltage measurements for those locations where the instant off potentials are less negative than –0.85 VDC to demonstrate and achieve acceptable criteria.
- The criteria for cathodic protection shall be in accordance with the Department of Transportation, Office of Pipeline Safety, Title 49, Part 195,

- The contractor shall record and plot on the appropriate data format the location of all cathodic test stations associated with but not limited to insulating joints, anodes, sleeves, rectifiers, valves and other meaningful pipeline or field components/conditions as well as those locations with significant stray current interference or depressed voltages (+/-25%) to facilitate positioning and analysis.

The contractor shall secure voltage recorders in areas determined to have stray current interference from the electrified railroad to ensure an uninterrupted 24-hour period to obtain an adequate sampling of voltage measurements for analysis.

A1.2: Direct Current Voltage Gradient Technique (DCVG)

DCVG (or alternatively ACVG) surveys are typically used to detect small to large holidays. They are sometimes used to determine whether a region is anodic or cathodic, but this technique cannot determine CP levels.

A1.2.1: Method, Equipment, and Reporting

Pre-job Considerations:

The following activities should be performed to allow the proper development of the DCVG coating evaluation:

A. Pipeline Data Collection:

- Pipeline material (steel, cast iron, etc.) and grade
- Diameter
- Length
- Wall thickness
- Year manufactured
- Type of coating

B. Pipeline Construction Data:

- Year Installed
- Route maps / Arial photos
- Construction Practices
- Road crossings along the pipeline route
- Location of valves, isolation devices (aboveground or underground), CP test points, electrical junction boxes
- Location of casings
- Pipeline depth of cover
- Soil chemical and physical properties
- Parallel pipelines in corridor and Pipeline crossings

C. Cathodic Protection System Data:

- Type of CP system (Impressed current or galvanic)
- Number and specifications of transformer rectifiers in the system
- Type of anode beds
- Cathodic Protection System Historical Data (On, Instant Off inspections, TR inspections, Close Interval Surveys, other CP system inspections)

D. Verification of the physical condition of the pipeline right of way

Instrumentation and Equipment:

Electrical measurements require proper selection and use of instruments. Recording potential differences require instruments that have appropriate voltage ranges. The user should know the capabilities and limitations of the equipment, follow the manufacturer's instruction manual, and be skilled in the use of electrical instruments. All survey equipment should be in good physical condition and properly calibrated before and during the Direct Current Voltage Gradient (DCVG) coating condition evaluation.

DCVG Equipment:

Interrupter: A DCVG (asynchronous) signal must be introduced to the pipeline system. This can be achieved by connecting a DC power supply unit to an Interrupter with a 1/3 of a second close and 2/3 of second open cycle and to the pipeline and a proper grounding. The equipment should be capable of raising a signal strong enough to create significant gradients around pipeline coating flaws. If available, the CP system can be used as a DC power supply.

DCVG Meter and probes:

Gradients in the soil must be measured with a digital or analog voltmeter with different voltage scales. The voltmeter must be connected to a pair of electrolytic probes.

Factors that may influence instrument selection for field testing:

- Input impedance (digital instruments)
- Input resistance or internal resistance (analog instruments)
- Sensitivity
- Conversion speed of analog-to-digital converters used in digital or data logging instruments
- Accuracy
- Instrument resolution
- Ruggedness
- Alternating current (AC) and radio frequency (RF) rejection; and
- Temperature and/or climate limitations

To log the coating flaw location, the distance to an above ground reference point must be measured. A pedometer may be used for that purpose. The precise distance must be measured along the pipeline route. If the DCVG equipment has no data logging capabilities, the distance information must be logged in a written format. The DCVG Operator may use a Geographical Positioning System unit to log coating flaw location.

Introduction of DCVG Signal in the pipeline:

Pipeline with no cathodic protection system installed: When an underground pipeline does not have a cathodic protection system, a DC interrupted current must be applied. A temporary DC supply unit must be connected to a proper grounding and to the pipeline through an interrupter with DCVG cycle interruption. The DCVG signal must be raised to an adequate level in the pipeline in order to locate small coating flaws at both ends of the section to be inspected. Verification must be done to guarantee the isolation of the DCVG signal from foreign pipelines and structures.

If the underground pipeline is protected with an impressed current CP system, the TR may be used as the DC power supply. An interrupter with DCVG cycle must be installed in between the TR and the pipeline. The DCVG signal must be raised to an adequate level in the pipeline in order to locate small coating flaws at both ends of the section to be inspected. Verification must be done to guarantee the isolation of the DCVG signal from foreign pipelines and structures.

Pipe Location and Marking Procedure:

To start a DCVG coating evaluation, the underground pipeline route must be determined. An electromagnetic pipe locator may be used to trace the pipeline route accurately. The pipeline route should be flagged at least every 100 feet to avoid misleading DCVG evaluation, especially if the coating is in very good conditions. If the coating condition is poor coating defects marking may act as pipeline route flags

Survey Procedure:

Verify adequate DCVG signal level at both ends of section to inspect

Data Validity: to be supplied
Data Format: to be supplied

1.3: AC Current Attenuation (ACCA)

This survey technique is typically used to qualitatively rank coating condition and highlight pipeline sections with the largest holidays. The C-Scan survey is used to detect various coating holidays on buried pipe, under paved areas and in frozen ground.

This technique was developed specifically to assess the electrical integrity of pipeline coatings on land based pipelines where the primary defense against external corrosion is the applied coating. A current is applied to the pipeline and coating damage is located and prioritized according to the magnitude of current attenuation.

The system is based on accurate measurement of the electromagnetic field radiated by a buried pipeline to which an AC signal current has been applied. The strength of the signal current remaining on the pipeline will decrease with increasing distance from the signal generator as the current gradually escapes to earth through the coating and any faults that may be present. The rate of loss (signal attenuation) will be dependent on the electrical integrity of the coating. In other words, the lower the coating conductance value, or the higher its resistance value, the lower the rate of signal loss. Any coating anomaly that results in a significant loss of current, hence changing the rate of attenuation for that section locally, can be observed readily by this survey technique.

The 'signal attenuation rate', usually measured in millibels per meter (mB/m) or millibels per foot (mB/ft), is the logarithmic rate of loss of signal current over the section of pipeline between any two survey points. The 'millibel' is a dimensionless ratio and thus independent of the value of the initial signal placed on the pipeline, and of the ground conditions (as they relate to total circuit impedance). It is determined by the average condition of the coating and by the area of coating in contact with the ground, per meter or foot of pipeline.

Therefore, for a pipeline of constant diameter the 'attenuation rate' is an absolute measure of average coating quality over each section surveyed. Using the electromagnetic field rather than ground contact means that the system is unaffected by variations in pipeline depth, changes in local electrical ground resistance or the presence of insulating ground surfaces such as ice, concrete, tarmac and sand.

Electromagnetic current attenuation survey systems can be used alone for overall coating evaluation (DA macro assessment) covering up to 30-50 miles (50-80 kilometers) per day and, alone or in combination with other techniques such as pin-to pin, DCVG or pipe to soil potential measurements, for location and/or evaluation of individual coating faults within an already identified 50-500 feet (15-150 meters). These will include sections showing 'high attenuation' on the macro assessment survey together with selected 'high consequence' (HCA) sections of pipeline (DA micro assessment). Coating condition can also be checked on newly installed or repaired pipelines, before back-fill is consolidated

In the most advanced electromagnetic current attenuation systems, all survey data can be stored internally and may be analyzed and displayed, or printed out in tabular or graphic form when required.

A1.3.1: Instrumentation and Equipment

The main elements of the system are the Signal Generator and the Detector, together with all necessary chargers, cables, earth spikes, etc. The accuracy and validity of data obtained with this method is dependent on the sophistication of design of the equipment which also significantly affects the surveyor/equipment interface in the field.

The signal generator should be a self-contained weatherproof unit powered by internal re-chargeable batteries that can operate in remote locations where an external power source may not be available. For prolonged operation, it is possible on most systems to augment the internal batteries with an external 12V DC power source (vehicle battery or similar). The signal generator should be to produce a fully stabilized AC signal at the selected frequency

Accurate survey results are primarily dependent on the analysis of relatively small differences in readings at successive locations. It is therefore essential that the input signal at the signal generator remains absolutely constant during the course of a survey. Once an appropriate output signal current has been selected by the operator, the signal generator should continue to output a constant current regardless of any changes of impedance in the external circuit, until the internal batteries or external power source are exhausted.

A1.3.2: Pre Survey Data Assembly

Before carrying out an electromagnetic current attenuation survey, it is advisable to collect as much as possible of the data listed below.

Pipeline Data

- Pipeline material (steel, cast iron, etc.) and grade.
- Diameter(s) and length
- Wall thickness.
- Product carried and operating pressure (nominal and maximum)
- Year manufactured.
- Type of coating
- Pipeline Construction Data –
- Year installed
- Route maps ('as built'), Arial photos
- Construction practices
- Road/rail/river/marsh crossings along pipeline route.
- Location of branches, valves, isolation devices (aboveground or underground), insulating joints, CP test posts, electrical junction boxes, sacrificial anodes, and CP ground beds.
- Location of casings/sleeves
- Pipeline depth (centerline and/or cover).
- Location and nature of all repairs and renovation (with dates) carried out over the last ten years.
- Location of all CP cross-bonds to other pipelines or structures indicating whether they can be disconnected.
- Existence of parallel pipelines and/or services in the pipeline corridor (right-of-way).
- Indication of any potential access barriers crossing the pipeline corridor (growing crops, dense undergrowth, fences, hedges, walls, or other structures)
- Soil chemical and physical properties.

Cathodic Protection System Data –

- Type of CP System (impressed current or galvanic/sacrificial anode)
- Number, locations and specifications of transformer/rectifier stations in the system.
- Type of anode beds/ground beds
- Historical data on CP System – CP current drain per mile/kilometer, CIS survey data, TR inspection data, CIS survey data, other CP system inspection data.
- Reports and results of all other surveys of the pipeline carried out in the last ten years.

A1.3.3: Survey Procedure

Before starting the survey it is essential that the operators carefully study the 'Operator's Manual' and any other material supplied by the manufacturer, together with relevant statutory or company regulations on operational health and safety. They should also check (against the packing list) that all the equipment, including spare batteries, is present. They must ensure that all periodic maintenance and charging procedures have been carried out and the equipment is in full working order.

WARNINGS: Before any connections are made to the pipeline it should be checked for any induced A.C. (from nearby HT power cables, AC traction systems, etc) High levels of induced A.C. could cause injury to any person who may act as a path to 'ground' by touching the pipeline or any lead or cable connected to it. Accidental 'earthing' of a strong induced A.C. current could also cause damage to some instruments and other equipment. Also, care must be used when operating this type of equipment on pipelines either inside the boundaries of, or connecting to facilities within, or even passing close by any airport. The nature of the AC signal being applied to the pipeline may have a serious adverse affect on the electronic systems used by the airport to communicate with and/or control aircraft in the vicinity.

The signal generator must be connected to the pipeline and to a suitable 'earth' point. Usually the best location for this is a transformer/rectifier CP station, making use of the CP ground-bed as the 'earth' connection, and the CP cable to the line as the 'pipe' connection. This must only be done after turning the transformer/rectifier off and disconnecting the CP cables from the ground bed and pipeline. If there is no T/R station in a suitable location, the signal generator can be connected to the pipeline via a CP test post (which connects to the pipeline). The 'earth' connection can then be set up nearby using one or more 'earth spikes' driven into the ground. This may not permit the applied signal to be as large as can be achieved using the T/R ground-bed, and the survey run may therefore be shorter.

Other possible connection points include block valves, insulating joints or other exposed sections of pipeline. The operator can then set the signal current. Detailed instructions for this will depend on the equipment being used and should be found in the manufacturer's 'Operators Manual'.

To minimize field interference, cables between the signal generator and the pipeline should be laid out at right angles to the pipeline, and the earthing point, whether ground-bed or earth spikes, should be at least 50 feet (15 meters) from the pipeline.

Survey Method

The first survey point – This should be at least 50 feet (15 meters) along the pipeline from the point where the signal generator is connected to the line. If the detector does not have integral GPS, a survey point should be selected which can be noted and used again for later surveys. The usual procedure is to approach the line at right angles until the detector indicates that it is precisely 'overhead'. For advanced systems, the operator is automatically guided to this position. For some other systems it may be necessary to make use of a standard pipe locator.

The detector should analyze the information collected by the antenna system together with the data entered by the operator, and display some or all of the following data:

- Overhead marker
- Survey reference, date, time and location number
- Depth of pipeline (cover or to centre-line)
- Pipeline diameter and wall thickness
- Strength of remaining signal current
- Latitude and longitude of present survey location (using GPS)

This data should be logged and, if possible, stored in the detector's computer. At each subsequent survey point (which may be several hundred meters or feet further along the pipeline) the detector should also display and store:

- Distance to any selected previous location (chainage or incremental)
- Signal attenuation rate over any section of pipeline
- Average coating conductance or resistance over the section (per sq.m or sq. ft.)
- If the equipment used does not generate, display and store this information automatically, the basic data must be noted down for later analysis.

The macro survey should continue with data collected at each survey location. Distances between survey points could be between 50 meters and 500 meters (150 -1500 feet) with even longer distances on lines with 'good' to 'excellent' coating. Any section indicating abnormally high attenuation may require additional readings to 'narrow down' the suspect section for subsequent 'micro' assessment to locate and evaluate individual faults.

The signal current remaining on the pipeline will reduce as the operator moves along the line. The rate of reduction will depend on the general condition of the coating. When the detectable signal falls below a useable level, it is necessary to move the signal generator to a new position and start the next 'leg' of the survey. The operator should ensure that there is an element of overlap between successive survey 'legs'.

When a general ('macro') survey has been completed, all survey data may be viewed on the detector LCD and it may be saved or downloaded to a computer for further analysis and printout in graphic or tabular form (if this facility is available on the system being used). Comparisons with previous survey profiles of the same pipeline may also be displayed to highlight areas of recent damage or deterioration over time. This operation can be carried out automatically with advanced current attenuation survey systems.

The printed-out survey report may indicate sections with unacceptably high attenuation levels and these may be the subject of 'micro' (close interval) surveys to locate and evaluate individual coating faults (holes and mechanical damage, general physical deterioration, porosity, cracking, contact with other buried services, etc). These faults may be located using different ground contact survey systems, provided good electrical contact with the ground can be achieved. Alternatively some current attenuation systems can be switched into 'close interval' (micro mode) to carry out this task, particularly where ground contact may be difficult. In micro mode, readings of 'current only' are taken at intervals of 2-3 meters (6-10 feet) over a 'suspect' section (say 75-100 meters – 200-300 feet). All the readings for each short survey are shown graphically and simultaneously on the LCD with the length of the baseline constantly adjusted to accommodate the readings. The location and significance of the individual faults can usually be clearly identified in this display

A1.3.4: Data Validity

The validity of the data generated is dependent on eliminating any possible causes of error to achieve the highest levels of accuracy and consistency in the readings recorded. Amongst the features necessary to obtain this in the most advanced current attenuation survey systems, are the following:

Applied signal current – The strength of the initially applied signal current must remain absolutely constant throughout the survey, since the determination of 'attenuation rate' and hence coating condition is determined by the ratio of one survey location reading to the next. A change of applied current due to small changes in ground resistance as the instrument is being moved between readings could produce a false reading of 'attenuation rate' and hence coating condition. It is therefore essential that the applied signal is constantly monitored and kept at the level set by the operator.

Operating frequencies – These should be crystal generated to maintain consistency of output and the operating frequencies selected must avoid, as far as possible any harmonics found with common ambient signals arising from other sources (50Hz, 60Hz, 100Hz, 120Hz, etc. etc.).

Antenna design – current attenuation systems use two or more groups of coils or other transducers that can derive the 'true' values of field strength and direction at every point, using the vector sum of the fields recorded. The overall length of the antenna assembly has been increased as far as is practicable with a hand-held 'field' instrument. This has produced further improvements in the accuracy of determination of 'depth' and 'current'.

Signal filtration – advanced detectors use very narrow band reception filters to minimize interference, and can 'warn' the operator if they receive large or anomalous transient signals (from 'above ground' sources, from AC traction systems, etc). In general, these will be 'ignored' by the system since it automatically analyses a large number of readings over several seconds before accepting them and proceeding to the next stage of calculation.

A1.3.5: Data Format

The format of the survey output will depend on the type of instrument being used. For a basic instrument, the information is noted down during the course of the survey - survey reference, location number, and distance from previous location (using road-wheel), and signal strength and pipeline depth. For a short survey with a strong signal, on a straight pipeline at a constant depth of about 1 meter (3 feet), this could be useful in indicating major problems, but would be of limited value for a long 'condition' survey, where pipeline depth may vary, and there would be rapid loss of accuracy with increasing depth or a low signal.

The more advanced current attenuation survey systems can automatically generate a range of timed and dated reports including the following:

- A point-to-point GPS 'map' of the pipeline showing all survey points
- A graphic plot or table showing the depth of the line
- ('cover' or to centre-line).
- A graphic plot or table showing signal current values for each survey location.
- A graphic plot or table showing absolute signal attenuation values, section by section.
- A graphic plot or table showing coating conductance or resistance (per sq. meter or sq. foot), section by section.
- A short range graphic plot of 'current' values for accurate fault location and evaluation when operating in close interval 'micro' mode.
- A table of pipeline identification information, survey equipment settings, and raw survey data with field notes recorded by the detector computer.

A1.4: Soil Models

Soil models have been developed to assist pipeline operators with the relative characterization of potentially significant SCC susceptible and non-significant SCC susceptible terrain conditions within a pipeline system. . A SCC Susceptibility Model is based upon the analytical results of extensive investigative excavations (i.e. SCC sites) and data compiled by pipeline owner/operators. The reliability and validity of any SCC Susceptibility Model is based upon investigative excavations and two important assumptions: disbonded coating and a susceptible line pipe steel.

The primary function of a SCC Susceptibility Model is not intended to predict the location of near critical SCC flaws or the next failure, but instead enables the identification of potential SCC susceptible areas along a pipeline. The practicality of a SCC Model allows valve sections or areas within a pipeline segment or system to be prioritized according to potential SCC susceptibility.

- A soil model is developed by combining terrain study information with available pipeline materials, construction and maintenance information.

The intuitive display allows the soil model user the ability to visualize numerous datasets at once and make educated integrity decisions quickly and decisively.

Attachment 2: AVAILABLE DIRECT EXAMINATION TECHNIQUES

Technical Background

A2.1: Investigative Excavations

Investigative excavations are to be used for direct validation of suspect anomalies identified during the pre-assessment or indirect inspection. Also, investigative excavations are to be used for validation of the DA methodology by direct examinations conducted at random sites not suspect or of concern (i.e. prove the null hypothesis). This involves uncovering short sections of pipeline (a minimum of one joint) at the locations considered most likely to contain an anomaly based on the indications completed during both the pre-assessment and indirect surveys. If anomalies are discovered that are severe enough to pose a threat to integrity in the future, then remedial action is taken. Severity of anomalies is to be determined using the repair criteria as delineated in the EMPCo Integrity Management Program Manual.

With the pipeline uncovered, the following direct inspections are required:

- classify and document terrain conditions (topography, soils, and site drainage) according to criteria developed by the DA service provider.
- assessment and documentation of coating conditions.
- sample and document pH values of electrolyte found beneath the pipeline coating.
- identify areas of coating disbondment for subsequent NDE analysis
- complete inspection of welds, long seams and areas of known or related integrity threats based on pipe manufacture or construction practices
- document and assess all detected integrity threats using internal or external codes, standards or procedures.
- incorporate findings into a database designed specifically for direct examinations
- adapt results for existing integrity programs as needed.

A2.2: Terrain Analysis

At each investigative site, the terrain conditions are recorded as the pipeline is excavated. The documentation of terrain conditions includes the identification of soil type, drainage, and topography parameters. Definitions and terms used by the DA service provider in the documentation of the terrain conditions at each investigative site are based on existing governmental (i.e. Agriculture Canada and USDA) procedures. The Canadian Energy Pipeline Association (CEPA) has adopted this classification system.

A2.3: Soil Type

The soil type classified at each investigative site is based on the mode of deposition and texture. Table A2.1 below lists the various soil environment descriptions:

Table A2.1: Soil Type Classifications

Soil Type	Description
Glaciofluvial/Fluvial	Sorted and stratified, sandy and/or gravel-textured material, which includes alluvial sand and gravel derived from relict watercourses.
Till (Morainal)	Variable soil texture with a variable-size range of unsorted stones. Includes gravel, sand, clay, and silt that were glacial in origin.
Lacustrine	Typically fine-textured deposits, clay to silt, with well-defined stratification. Deposits are formed in standing bodies of water.
Alluvial	Commonly rocky, gravel-textured sediment that is stream-derived.
Eolian	Wind-derived material, usually fine to very fine textured sands.
Organic	Partially decomposed organic material.

A2.4: Soil Drainage

The soil drainage is determined at pipe level based on soil characteristics such as depth of mottling and gleying or the absence of soil drainage impediments from the soil surface. Listed below are the definitions of drainage classifications identified at each site:

Table A2.2: Soil Drainage Classifications

Drainage Type	Description
Well Drained (W)	Oxidizing environment throughout the year.
Imperfectly Drained (I)	Alternating oxidizing and reducing environment. The environment is dependent on fluctuation of the water table.
Poorly Drained (P)	Primarily reducing conditions. The environment may be saturated throughout most of the season.
Very Poorly Drained (VP)	Reducing conditions throughout the entire year. The environment is saturated year-round.
Very Poorly – Very Poorly Drained (VP-VP)	Reducing conditions throughout the entire year. The soil consists of organic material and the environment is saturated year-round. Standing bodies of water are present on surface topography.

A number of factors can help determine the drainage of the soil. They are:

- Presence of an organic layer;
- Water table depth;
- Presence, abundance, and depth of mottles in the mineral soil; and
- Presence and depth of gley colors in the mineral soil.

The presence of a layer of organics on top of the mineral soil can also be indicative of the soil's drainage. A layer of 40 cm or more of organics indicates a very poorly drained soil.

Seasonal changes in the water table need to be considered when determining drainage. For example, if the water table depth is above the top of the pipe throughout the year in a mineral soil, the drainage can be classified as very poor.

Mottling of the soil appears as a blotches or spots of a different color or shade of color generally yellow to red hues than the main soil color. Mottled soils are indicative of a fluctuating water table, which produces alternating reducing and oxidizing conditions, and are mainly associated with imperfect or poorly drained soils.

Gleying of the soil appears as a gray to blue or green color within the soil matrix. Gleyed soils are indicative of saturated or reducing conditions throughout the year, and are mainly associated with poorly or very poorly drained soils.

The soil profile does not need to exhibit mottling or gleying if the drainage is imperfect, poor, or very poor.

A2.5: Topography

The topography at each site is documented according to the landscape pattern. Listed below are the topography and site position classifications used during each investigative program:

Table A2.3: Topography Classifications

Topography	Description
Undulating (U)	Regular sequence of gentle slopes from alternating concave and convex patterns.
Ridged I	Sharp crested or dome shaped.
Inclined (I)	Sloping surface.
Level (L)	Flat to very gently inclined.
Depressed (D)	Topographically low-lying area.
Side Slope (S)	Side slope of an incline, perpendicular to the pipeline right-of-way.

A2.6: Site Position on a Slope

The location of the site was identified with respect to local topography according to the following criteria:

Table A2.4: Site Position Classifications

Site Position	Description
Crest	The uppermost portion or apex of a slope.
Upper Slope	The uppermost portion of a slope immediately below the crest.
Middle Slope	The area between the upper and lower slope.
Lower Slope	The lower portion of the slope immediately above the toe.
Toe	The lowermost portion of the slope.
Depression	Any area that is concave in all directions.
Level	Any level area.

A2.7: Carbonates

The presence or absence of carbonates (CO_3^{2-}) within a soil profile is indicative of the carbon dioxide (CO_2) levels in the pipeline environment. Near neutral pH stress corrosion cracking (SCC) has been associated with soils with higher levels of CO_2, which forms carbonic acid, a weak acid within the pipeline environment.

A2.8: Soil Resistivity

Soil resistivity is measured using the Wenner 4 pin method. Higher soil resistivity may prevent CP current from reaching the pipeline.

A2.9: Coating Assessment

After the pipe is excavated, the pipeline coating condition is inspected and documented at each investigative site. In most cases, the furthest upstream girth weld is located to provide a reference point and all subsequent measurements are referenced to it. This girth weld is referred to as the reference girth weld, and is located between joint AA (upstream) and joint A (downstream). Personnel from the DA Service provider can identify and document the long seam (or other weld type) and girth weld positions at each site.

On a joint-by-joint basis, the coating condition is identified and documented. The coating conditions that are documented include areas that are well bonded, areas of disbondment, tented regions across welds, and locations of holidays. Below, Table 5 outlines the general definitions used to qualitatively characterize pipeline coating conditions:

Table A2.5: Qualitative Condition Descriptions

Coating Condition	Description of Disbonded Coating	Common Corrosion Deposits Pattern
Excellent	Very good adhesion; continuous thickness; <1% disbondment; an occasional holiday.	None
Good	1 to 10% disbondment; scattered holidays; good adhesion.	Spotty
Fair	10 to 50% disbondment; scattered to numerous holidays; random areas of poor adhesion.	Spotty to Intermittent
Poor	50 to 80% disbondment; numerous holidays; multiple or long areas of poor adhesion.	Intermittent to Continuous
Very Poor	>80% to total disbondment; numerous holidays; no adhesion, brittle coating.	Continuous to Dense

The description of the coating condition is correlated to the terrain conditions on a per-joint basis, allowing the DA Service Provider to determine the probability of similar coating conditions throughout a pipeline system.

A2.9: Corrosion Deposits and Electrolytes

Upon removal of the coating, the presence or absence of corrosion deposits is noted. Documentation of the corrosion deposits includes the color, texture, and distribution. These physical properties assist with identification of the corrosion deposits in the field.

Common corrosion deposits found beneath pipeline coatings can include:

- White, pasty iron carbonate ($FeCO_3$) - anaerobic, strong association with SCC, cathodic shielding and external corrosion;
- White, powdery calcium carbonate ($CaCO_3$) - indicative of a functioning CP system;
- Black, metallic/hard/pasty/powdery iron sulfide (FeS) - indicative of the presence of sulfate reducing bacteria (SRB);
- Orange/gray, powdery/scaly/film iron hydroxides and oxides (FeO, Fe_3O_4, FeO/OH) consisting of magnetite, maghemite, goethite, and lepidocrocite - variable aerobic/anaerobic conditions.

In order to properly assess an investigative site and its relationship to environmental conditions and integrity concerns, it is necessary to correctly identify corrosion deposits and the pH of the electrolyte beneath the disbonded coating. When combined with other specific environmental parameters, certain corrosion deposits are indicative of either the presence or absence of SCC, external wall loss, and microbial induced corrosion.

In the event that electrolyte is present between the surface of the pipe and coating, its location and properties are recorded. Electrolyte color is recorded and electrolyte pH is visually measured using pH litmus paper. Non-classical SCC is commonly associated with an electrolyte pH reading between 6.0 and 8.5; classical SCC is known to be associated with an electrolyte pH range between 9.0 and 11.0. SCC is not known to occur when the electrolyte pH is greater than 11.0.

If the presence of bacteria is suspected, corrosion deposit samples are collected and analyzed by population density, general bacteria type (SRB or APB), and by-product type (i.e. type of organic acid).

A2.10: Pipe-to-Soil Reading

A voltmeter and a $Cu/CuSO_4$ electrode are used during an investigative excavation to obtain CP readings at the 12:00 o'clock, 3:00 o'clock, 6:00 o'clock, and 9:00 o'clock positions at regular intervals along the pipeline. For short excavations, the readings will be taken at the upstream and downstream ends of the excavation. These readings will show whether the CP is reaching all areas of the pipeline or if there is any CP drop over the length of the excavation

A2.11: Non-destructive Testing

Following the completion of the terrain, coating, and corrosion deposit assessments, the pipe is prepared for MPI. Areas inspected typically include:

- Girth welds and associated pipe on either side of the weld;
- Long seams and associated pipe on either side of the weld;
- Coating holiday locations; and
- Disbonded coating areas.

The pipe is prepared for MPI (ASTM E709 Standard) with a high-pressure air blasting system that uses an abrasive substance consisting of crushed walnut shells, glass beads, or another accepted medium. The air blast system must be of sufficient size to produce 100 psi at the blast tip. This procedure is conducted under the guidance of qualified personnel and is conducted to remove any remaining coating, primer, and/or corrosion deposits from the pipe surface that may hinder the MPI and the identification of SCC or other pipe surface anomalies.

A2.12: Magnetic Particle Inspection

The DA service provider shall use one of two methods to detect SCC on ferromagnetic steel pipelines: Wet fluorescent magnetic particle inspection (WFMPI) and black on white contrast magnetic particle inspection (BWMPI). Both inspection methods are proven procedures for detecting external SCC and other surface anomalies.

Comparatively, the WFMPI method is more economical and generally less time consuming than BWMPI. However, BWMPI is required to document and photograph any external discontinuities detected. BWMPI is a favorable inspection method for short excavations (i.e. less than one full joint length) or if the site is excessively wet. If the ambient air temperature is above 20° Celsius, BWMPI is also the preferred inspection method due to the possible fatigue of inspection.

If any SCC colonies or other surface indications are detected on the pipe, each individual colony or indication is measured and documented by Marr personnel, except when physical constraints hinder this action (i.e. beneath the

pipe in tight locations). The depth of all detected SCC colonies are then visually estimated as a throughwall percentage of the pipe wall thickness.

In the event that SCC colonies are detected during the MPI inspection, selected SCC colonies will be removed by buffing. The colonies are buffed out using a grinder with a rubber-backed sanding disc. The reasons for buffing the SCC colonies are to:

- Verify the visual depth estimate;
- Verify the actual depth of the SCC colony; and
- Remove the colony from the pipe wall.

To determine the crack depth, UT wall thickness measurements are made before and after the colony is removed. The difference between the two readings is the throughwall depth of the colony, which is then recorded as both a percentage of the pipe wall thickness and in terms of millimeters.

SCC colonies occurring near or within external corrosion features are also evaluated. The SCC colonies near external corrosion are documented with the procedure outlined above, but the occurrences within external corrosion must be evaluated in conjunction with the depth of corrosion.

SCC colonies in external corrosion are usually visually estimated for depth. UT wall thickness measurements are made in the corrosion feature to determine the remaining wall thickness. The corrosion's throughwall depth and the SCC colony depth are both considered in determining the overall depth of the SCC colony. The procedure for documenting external corrosion is explained in the proceeding section.

A2.14: Corrosion Feature Assessment

To accurately document an external corrosion feature, a reference point is defined as the upper left corner of the feature. This reference location is defined as the distance from the girth weld and the circumferential distance from the top of the pipe. The overall axial and circumferential lengths of the feature are recorded. The corrosion feature is then prepared for mapping by superimposing a grid over the entire anomaly area. The grid size utilized is dependant on client preference, but typically, a 1 to 3 cm grid is used to delineate the corrosion feature area. UT techniques or mechanical gauges are used to obtain the remaining wall thickness readings at each grid reference node, both axially and horizontally along the pipe. The wall thickness readings are recorded in a spreadsheet.

A pit depth gauge is used to map the depth of the corrosion feature. The two edges of the pit gauge, which extend out 2 inches on either side, must be positioned on uncorroded pipe in order to obtain an accurate pit gauge reading. This procedure allows the corrosion depth to be assessed in reference to the original outside diameter of the pipe. In the event that the corrosion feature is extensive, a bridging bar is required in order to obtain representative readings. The bridging bar is positioned on the pipe so that measurements are calibrated from a flat surface.

UT pencil probe measurements are made using a ¼ in. ultrasonic transducer with a conical delay line of 1/8 in. diameter at the tip. Pencil probes measure the remaining wall thickness, while the pit gauge measures the corrosion depth. The pencil probe method is more versatile than the pit gauge technique because it is not limited by the requirement of a flat, uncorroded pipe surface to bridge the pit gauge across.

A2.15: Guided Wave Ultrasonic Testing - GWUT

The Guided Wave Ultrasonic Testing (GWUT) system is capable of characterizing long runs of pipe from a single set-up point. GWUT is a low frequency ultrasonic tool that can detect wall thickness variations in pipe up to 250 linear feet in either direction from a single inspection point. This method requires that coating and/or insulation be removed or access provided to only 24 inches of clean pipe with 6 inches clearance above and below circumferentially.

The tool can handle pipe sizes down to two (2) inches in diameter. The largest diameter pipe that can be inspected at the present time is 60 inches. This method has proven to be cost effective for inspections of piping at the soil-to-air interface and at road crossings where excavation would be costly and time consuming. Other applications are overhead lines where scaffolding would be required, on insulated lines where insulation removal would be time consuming or hazardous (asbestos), and for corrosion under insulation (CUI) inspections.

This method also provides a cost effective solution for assessing the unpiggable sections of pipelines. The technique has been employed on buried sections of pipe and routinely achieves inspection distances of 90 to 100 feet in each direction from the bell hole. Special techniques have also been developed that yield good results on lines that penetrate concrete walls going to a buried pipe section. One of the side benefits of utilizing the system is locating the position of welds along buried or insulated lines. This can be valuable information relative to corrosion mechanisms operating on a line and in locating and verifying signals received from questionable areas along the line.

Attachment 3 : EXECUTION

A3.0 Pre-Screening

A3.0.1 Identification of Candidate DA Pipeline Segments

Pipeline segments that are likely candidates for DA are identified from the HCA database or identified by field operations units. These candidate pipeline segments usually have some or all of the following attributes:

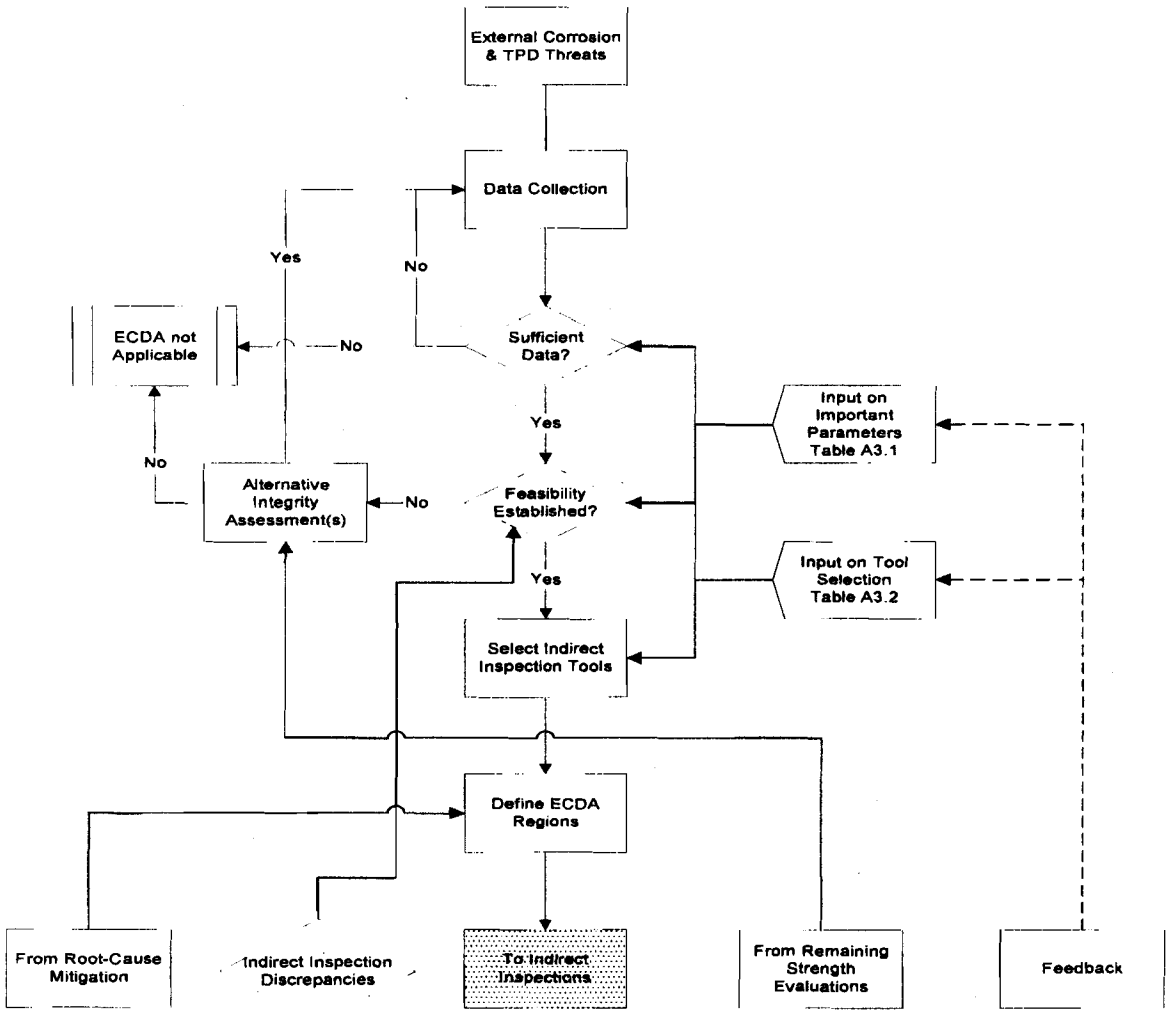
- Short length (normally less than a mile)
- No pig launching or receiving capabilities or impediments to smart pigging (internal coating)
- Difficulty in obtaining shutdown of the segment
- Little or no tolerance for entrained water
- Not susceptible to long seam failure
- Not susceptible to internal corrosion *
- Not susceptible to SCC *
- Transported material not compatible with ILI tools (pipe ID buildup, etc.)
- Readily accessible for indirect inspection techniques (no major waterway crossings, able to be traversed by foot, etc.)
- Coating compatibility with Indirect Inspection Techniques
- Good records of pipeline installation and operation including specifications, materials, coating (ECDA not applicable to bare pipe or disbonded, monolithic coating), inspection records, and leak history
- This list is not inclusive, other difficulties could render DA not applicable. Conversely, a pipeline segment could have attributes that initially make it a difficult line to assess with DA but the difficulties may be overcome with more extensive Indirect Inspection Tool (IIT) or Direct Examination methods.
- DA Technology and methodologies to evaluate Internal Corrosion and Stress Corrosion Cracking not available at the time this document was prepared.

A3.1 Pre-Assessment:

A3.1.1 Objectives:

- Collect the needed pipeline data to determine the feasibility of conducting DA
- Determine the feasibility of conducting DA for the pipeline segment
- Select Indirect Inspection Techniques (IIT)
- Establish ECDA Regions
- Document Pre-Assessment Results

Figure A3.1: Pre-Assessment Flow Chart



See Figure A3.2 (Indirect Assessment) for Continuation

A3.1.2 Data Collection

The following data sets should be investigated and attempts made to find any applicable records to fill in information:

Table A3.1: Direct Assessment Data

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Pipe Data				
Material and Grade	ECDA not applicable to non-ferrous materials	Consideration to locations where dissimilar metals join	Can create local corrosion cells	Required
Diameter	May reduce detection capability of IIT		Influences currect flow and interpretation of results	Required
Wall Thickness			Impacts critical defect size and remaining life predictions	Required
Year Manufactured			Older pipe materials may have lower toughness levels, reducing critical defect size and remaining life calculations	Consider
Seam Type	ECDA not applicable to seam failure susceptible pipe	Increased selective seam corrosion suscepotibility may require separate ECDA regions	Older pipe may have lower toughness in seams or be more susceptible to seam selective corrosion	Required
Bare Pipe	Limits ECDA tool selection	Bare pipe should be a separate region from coated pipe	See Attachment 1 for applicable ECDA methods	Required

Required = Data that must be available or be acquired during the DA process for ECDA Applicability

Desired = Data that is helpful to the DA Process, but may be obtained during the DA process

Consider = Data that is potentially helpful to the DA process but not required

Example: Depth of cover is Desired to be available during pre-assessment but will be obtained during the DA process anyway, therefore that data is not Required prior to performing the DA process.

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Construction Data				
Year Installed			Impacts time over which coating degradation could occur, defect population estimates, corrosion rate estimates	Required
Route Changes/ modifications		Changes may require separate DA regions		Desired
Route Maps/Aerial Photos		Provides general applicability information and DA region selection	May contain pipe data that could help facilitate DA	Desired
Construction Practices		Differences in construction methods could require separate DA regions	May indicate locations where construction problems may have occurred, backfill practices influence coating damage	Desired
Locations of Valves and other major appurtenances		Significant changes in CP current could occur, consider dissimilar metals	May impact local current flow and interpretation of results, dissimilar metals could create local corrosion cell, coating degradation rates may be different	Desired
Location of casings and construction methods	May preclude use of certain IIT	Requires separate DA region	May require operator to extrapolate nearby results to inaccessible regions. Additional tools could be required	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Construction Data (continued)				
Location of bends		Presence of miter or wrinkle bends may influence DA Regions	Coating degradation may be at different rates, corrosion on bends can be localalized, affecting local current flow and interpretation of results	Desired
Depth of Cover	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results	Desired
Underwater sections	Significantly restricts the use of many IIT	Requires separate DA regions	Changes current flow and interpretation of results	Required
Road and river/marsh crossings	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results	Desired
Location of river weights and anchors	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results, corrosion near weights and anchors can be localized	Desired
Proximity to other pipelines, structures, high-voltage electric transmission lines, rail crossings	May restrict the use of some IIT	Regions where the CP currents are significantly affected by external sources should be treated as separate DA regions	May impact current flow and interpretation of results	Desired

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Soils and Environmental				
Soil Characteristics	Some soil characteristics reduce the accuracy of various IIT	Influences where corrosion is most likely, significant differences require separate DA regions	Useful in interpreting results. Influences corrosion rates and remaining life assessment	Desired
Drainage		Influences where corrosion is most likely; significant differences require separate DA regions	Useful in interpreting results. Influences corrosion rates and remaining life assessment	Desired
Topography	Conditions such as rocky areas can make IIT inspections difficult or impossible			Desired
Land Use (current and past)	Paved roads, etc. Influence IIT selection	Can influence DA application and region selection		Required
Frozen Ground	May impact applicability and effectiveness of some DA methods	Frozen areas should be considered separate DA regions	Influences current flow and interpretation of results	Required
Corrosion Control				
CP System Type (anodes, rectifiers, locations)	May effect IIT DA tool selection		Localized use of sacrificial anodes within impressed current systems may influence current flow and interpretation of results	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Corrosion	**Control (cont'd)**			
Stray current source/location			Influences current flow and interpretation of results	Desired
Test point locations (or pipe access points)		May provide input to DA region selection		Required
Foreign pipeline crossings		May provide input to DA region selection	Influences current flow and interpretation of results	Desired
CP Cross Bonding to other pipelines or structures		May provide input to DA region selection	Influences current flow and interpretation of results	Required
CP evaluation criteria			Used in post assessment analysis	Required
CP maint. history		Coating condition indicator	Can be useful in interpreting results	Desired
Years without CP applied		May make DA more difficult to apply	Negatively affects ability to estimate corr. rates and make remaining life predictions	Desired
Coating type - pipe	ECDA may not be applicable to disbonded coatings with high dielectric constants, which can cause shielding		Coating type may influence time at which corrosion begins and estimates of corrosion rates based on measured wall loss	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Corrosion	**Control (cont'd)**			
Coating type - joints	ECDA may not be applicable to coatings which can cause shielding		Shielding due to certain joint coatings may lead to requirements for other assessment activities	Desired
Coating condition	DA may be difficult to apply with severely degraded coatings			Desired
Current demand			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface	Desired
CP survey data/history			Useful in interpreting results.	Desired
Operational	Data			
Pipe Operating Temperature		Significant differences generally require separate DA regions	Can locally influence coating degradation rates	Desired
Operating stress levels and flunctuations			Impacts critical flaw size and remaining life predictions	Required
Pipe inspection reports - excavations		May provide input when defining DA regions		Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Operational	**Data (continued)**			
Monitoring programs (coupons, patrols, leak detection, etc.)		May provide data when defining DA regions	May impact repair, reemediation, replacemetn schedules	Desired
Repair history/records (sleeves, locations, etc.)	May affect DA IIT selection	Prior repair methods, such as anode installations, can create a local difference that may influence DA region selection	Provides useful data for post assessment analyses such as interpreting data near repairs	Desired
Leak/Rupture history		Can indicate condition of existing pipe		Required
Evidence of external MIC			MIC may accelerate external corrosion rates	Desired
Third Party Damage freq.		Critical to detemine TPD threat risk	High TPD areas may have increased IIT coating faults	Required
Data from previous IIT surveys			Essential for preassessment and DA region selection	Required
Hydrotest dates & pressures			Influences inspection intervals	Desired
Land Use		Could indicate TPD risk	changes affect TPD risk	Desired
Other prior integrity related activities (CIS, ILI results, etc.)	May impact IIT selection - isolated versus larger corrosion areas		Useful post assessment data	Required

A3.1.3 Feasibility Assessment

The amount and quality of data collected in the pre-assessment shall be used by the Field Steward and/or the Qualified Individual to determine if the DA process can reasonably be applied to the pipeline segment. If conditions are such that DA is not applicable, the Field Steward shall make the appropriate HCA schedule change due to assessment method change (and probably timing as well).

Table A3.2: ECDA Tool Selection Matrix

CONDITIONS	CIS	DCVG/ACVG	ACCA	GWUT
Coating holidays	Yes	Yes	Yes	No
Anodic zones on bare pipe	Yes	No	No	Yes
Near river or water crossing	Yes	No	Yes	Yes
Under frozen ground	No	No	Yes	Yes
Stray currents	Yes	Yes	Yes	No
Shielded corrosion activity	No	No	No	Yes
Adjacent metallic structures	Yes	Yes	Yes	No
Near parallel pipelines	Yes	Yes	Yes	Yes
Under high voltage AC electric lines	Yes	Yes	No	Yes
Shorted casings	Yes	Yes	No	Yes
Under paved roads	No	No	Yes	Yes
Uncased crossing	Yes	Yes	Yes	Yes
Cased piping	No	No	Yes	Yes
At deep burial locations	Yes	Yes	Yes	Yes
Wetlands	Yes	Yes	Yes	Yes
Rocky terrain/backfill	No	No	Yes	Yes

A3.1.4 Indirect Inspection Tool Selection

A minimum of two complete IIT methods shall be employed for the entire length of the pipeline segment to be assessed by DA. Tools shall be selected based upon their ability to detect corrosion activity and/or coating faults reliably under conditions present for the specific pipeline being assessed. Tools shall also be selected based upon their compatibility with each other. A 100% direct examination that follows the requirements of Attachment 2 of this document in lieu of indirect inspections combined with direct examinations can be substituted where feasible. Pre-Assessment and post assessment steps are still required when substituting 100% direct examination for indirect inspections. Table A3.2 can be used to assist in the IIT decision making process. In some cases 3 or more Indirect Inspections techniques may be required to get acceptable IIT results. The DA Service Provider shall notify the DA Field Steward if more than 2 IIT surveys are required.

A3.1.5 Identifications of DA Regions

The DA service provider will analyze the data collected in the Pre-Assessment step to identify DA Regions. A DA Region is a portion of a pipeline segment that has similar physical characteristics, corrosion histories, expected future corrosion conditions, and that uses the same Indirect Inspection Tools. All conditions that could significantly affect corrosion will be considered by the DA service provider when defining DA regions using Tables A3.1 and A3.2 of this section as well as other information provided by the DA service provider and EMPCo personnel. DA region definitions may be modified based upon results of the Indirect Inspections and the Direct Examinations. A DA region does not need to be contiguous, it may be broken for a river crossing but extend on either side of the crossing. An entire pipeline segment could also be one contiguous DA region. Once the DA service provider has determined the DA region(s) for a particular pipeline segment, it shall be reviewed with the Field Steward and modifications made as desired. DA regions should be documented at the end of the Pre-Assessment Step of DA by the service provider and that documentation modified as necessary during Indirect Inspections and Direct Examinations. A final document delineating the DA regions used in the assessment will be located in the final report by the DA service provider.

A3.1.6 Pre-Assessment Review Meeting

A meeting between the DA service provider and the Field Steward (and other data sources as necessary) will be held to answer any questions the DA service provider has remaining about the data, interview those with knowledge of the pipeline segment, and advise of the proposed selection of DA regions and IIT equipment for each region of the pipeline segment that have been selected. Expected outcome of this meeting is finalization of the DA region selection and IIT methods to be used. It is expected that the DA service provider should conduct the Pre-Assessment meeting and have identified DA regions and IIT proposed surveys within one month of approval from the Field Steward to begin a DA assessment. Integration of the pre-assessment data is critical in determining applicability of the DA process and in determining the applicable threats identified from the history of the pipeline segment. In some cases, the amount and quality of the data available on the pipeline segment may invalidate its selection as a candidate for DA. In all cases, the outcome of the Pre-Assessment shall be documented in a detailed report provided by the DA Service Provider.

A3.2 Indirect Inspections

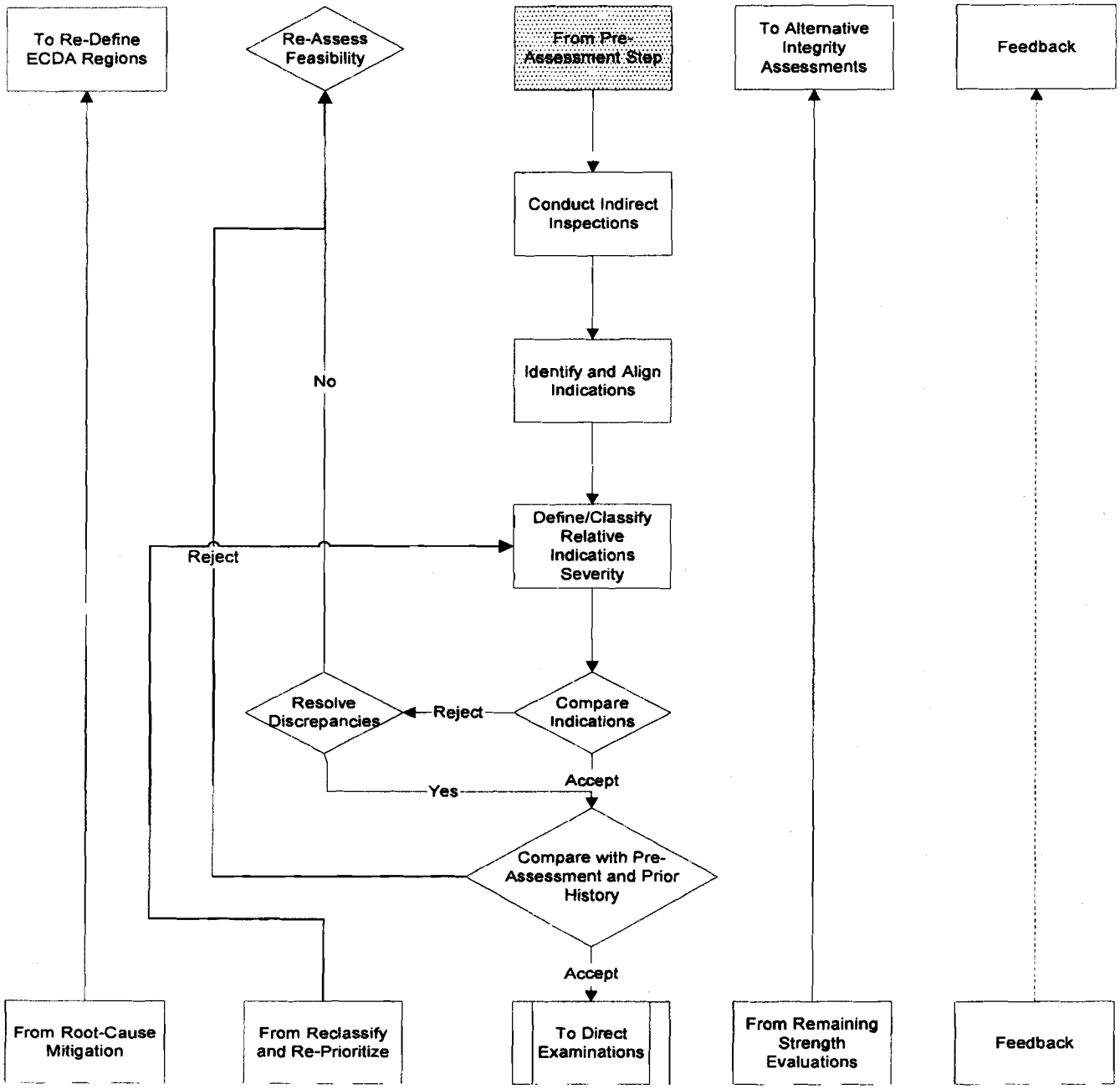
A3.2.1 Objectives:

- Locate and define the severity of coating faults, other anomalies, and areas where external corrosion and third party damage may have occurred.
- Conduct at least two indirect inspections over the entire pipeline segment
- Align and compare the results from the IIT surveys
- Identify and classify indications
- Analyze and report results for the Direct Assessment Step

A3.2.2 Conducting and Aligning the IIT Surveys

Boundaries of each DA region should be clearly identified and marked in the field for reference while performing IIT. Consideration to overlapping IIT across the DA region boundaries should be made by the DA service provider for completeness of data gathering. Additional IIT surveys may be determined to be necessary during the Indirect Inspection Step if IIT equipment does not perform as predicted or if different conditions are found that negates the accuracy of the IIT methods chosen in the Pre-Assessment Step. IIT methods shall be performed per the attached Appendix 1. The Indirect Inspection Step shall follow the attached Indirect Inspection Flow Chart Figure A3.2. When DA is applied for the first time, EMPCo and the DA service provider should consider spot checking, repeating IIT surveys, or other verification measurements to ensure consistent data is collected. IIT survey data points shall be conducted using intervals spaced closely enough to permit a detailed assessment, with the goal to use the IIT such that coating defects, possible corrosion, and anomalies can be detected with reasonable certainty. Normally, IIT survey data points shall be collected in spacing from 2.5 to 10 feet along the length of the pipeline. In some cases and with some IIT surveys, initial spacing can be more than 10 feet provided that detailed IIT surveys are conducted in areas with coating fault indications or in areas with suspect indications.The separate IIT surveys should be conducted as close in time as practical to avoid weather changes and changes normally occuring to CP systems over a longer period of time. If significant changes occur between the IIT surveys (such as a change of seasons or a change in pipeline configuration) comparison of results will be affected and may become difficult or invalid. Aboveground location measurements should be referenced to consistent geographic locations (for instance using GPS Coordinate systems) and so documented so that inspection results can be compared and used to identify excavation locations and for future reference. Overlay of IIT surveys shall be aligned on a common mapping system such as a Geographic Information System.

Figure A3.2: Indirect Inspection Flow Chart
(continuation of Fig. A3.1: Pre-Assessment Flow Chart)



(Continued on Direct Inspection Flow Chart: Fig. A3.3)

A3.2.3 Defining and Classifying Indication Severity

Classification of anomalies identified during the Indirect Inspection Step is a process of estimating the likelihood of corrosion activity at each indication under typical year-round conditions. Anomalies shall be classified according to the following:

Severe: Indications that the DA service provider considers as having a high likelihood of corrosion activity or a high likelihood of TPD.

Moderate: Indications that the DA service provider considers as having possible corrosion activity.

Minor: Indications that the DA service provider considers as having a low likelihood of corrosion activity.

The criteria for classifying the severity of anomalies shall take into account the capabilities of the IIT used and the unique conditions of the DA region examined. When DA is used for the first time, indications that the DA service provider cannot determine whether corrosion is active shall be classified as severe. The following Table A3.3 gives example severity criteria to be used for the IIT methods identified in Appendix 1 of this document. The table is a general guideline and not meant to be absolute. The DA service provider must consider specific conditions along the pipeline and the accuracy of the inspection methods when classifying indications. The DA Service Provider shall give special attention to the location of coating failures or stray currents in areas where TPD could be expected (such as in areas of foreign line crossings or subsurface construction or in areas of shallow cover with farming operations).

After indications have been identified and classified, the DA service provider shall compare the results from the separate IIT methods to determine consistency. If two or more IIT indicate significantly different sets of locations at which corrosion activity may exist and if the differences cannot be explained by the inherent capabilities of the tools or specific and localized pipeline features or conditions, additional indirect inspections or preliminary direct examinations should be considered. Preliminary direct examinations may be used in lieu of additional IIT surveys provided the direct examinations identify a localized and isolated cause of the discrepancy(s). If additional IIT surveys or Direct Examinations do not resolve the discrepancies, DA feasibility should be re-assessed. During initial DA applications, locations at which discrepancies cannot be resolved shall be treated as a severe indications. Locations with indications at foreign line crossings or other areas where a high likelihood of TPD exists shall also be treated as severe indications. Once IIT discrepancies are resolved, the DA service provider shall compare the IIT survey results with the Pre-Assessment results and prior operating history for each DA region and the entire pipeline segment being assessed. If the IIT surveys are not consistent with the Pre-Assessment results, the DA service provider shall re-assess DA feasibility. Following validation that IIT methods have confirmed Pre-Assessment prediction results, the DA service provider shall report to EMPCo's Field Steward the results of the IIT surveys and explain any additional validation IIT surveys required for the Indirect Inspection Step and any re-validation of pre-assessment activities required to align the Pre-Assessment predictions with the Indirect Inspection results.

A3.2.4 Defining and Classifying Indication Severity (continued)

Table A3.3: Severity Classification

Tool/ Environment	Minor	Moderate	Severe
Close Interval Survey (aerated, moist soil)	• Small depression in potential profile • "On" and "Off" potentials are both more negative than -850 mV	• Medium depression in potential profile • "On" potentials are more negative than -850 mV • "Off" potentials are not more negative than -600 mV	• Large depression in potential profile • "Off" potentials are not more negative than -600 mV
DCVG Survey (aerated, moist soil)	• < 36% IR • Cathodic both "On" and "Off"	• 36% to 60% IR • Cathodic "On" • Anodic or Neutral "Off"	• > 60% IR • Anodic both "On" and "Off"
AC Current Attenuation survey (Pipeline Current Mapper or C-Scan)	• -9 to -30 mdB/ft	• -31 to -60 mdB/ft	• > -60 mdB/ft

A3.2.5 Deliverables from IIT

The DA service provider shall provide the IIT surveys with a minimum of the following pipeline attributes identified and aligned with the IIT survey data:

- Identification of line segment (map number and segment name from HCA database)
- Station numbers and GPS Coordinates of starting and stopping locations and all identified attributes (from alignment sheets or schematics).
- PI's with stationing and GPS coordinates
- Depth of pipeline (at least every 100 feet)
- Pipeline Markers and Test Leads with stationing and GPS coordinates
- CP Equipment, type and location with stationing and GPS Coordinates
- Land use descriptions
- Valves with stationing and GPS Coordinates
- Roadway descriptions (name and orientation) with stationing and GPS Coordinates
- Topographical features

The DA service provider shall compare the results of the Indirect Inspection results with the Pre-Assessment results and prior maintenance history of the pipeline segment to see if they validate each other. If the assessment results are not consistent with the operating history of the pipeline, the DA service provider must reassess the feasibility of the DA process. The DA service provider shall prepare a summary Indirect Inspection Report for the pipeline segment being assessed with at least the following elements:

- DA Region Report (can be identical to report prepared in A3.1.5 above)
- Indication Classification and Direct Examination proposed sites

Results from the IIT surveys shall be delivered to the Field Steward within 60 days of completion of the field work associated with the IIT. The results shall be complete with dates that inspections were performed, description of the IIT surveys performed and over what stations of the pipeline, the names of personnel who performed the IIT surveys, and summary information. The results can be in either electronic or hard copy format according to the preference of the Field Steward. An Excavation Plan shall be prepared by the DA service provider with a prioritized list of planned Direct Examination excavation sites. HCA maps shall have been delivered to the DA service provider from EMPCo's Field Steward at the time of the Pre-Assessment meeting

Table A3.4: Prioritization of Indirect Inspection Indications

		Close Interval Survey			
		Severe	**Moderate**	**Minor**	**No Indication**
DCVG	Severe	Immediate	Scheduled	Scheduled	Monitored
	Moderate	Immediate	Scheduled	Monitored	No Action
	Minor	Immediate	Scheduled	Monitored	No Action
	No Indication	Immediate	Scheduled	Monitored	No Action
ACCA	Severe	Immediate	Scheduled	Scheduled	Monitored
	Moderate	Immediate	Scheduled	Monitored	No Action
	Minor	Immediate	Scheduled	Monitored	No Action
	No Indication	Immediate	Scheduled	Monitored	No Action

Immediate indications from the above chart shall be treated equivalent to an Immediate Repair indication from an ILI Tool Run as delineated in the EMPCo IMP Manual, whereas Scheduled indications can be treated as a 60 day or 180 day repair in the EMPCo IMP. For example, a point where CIS data indicates a potential of -400 mV off (severe CIS Indication) and ACCA indicates more than -60 mdB/ft (severe ACCA indication) shall be treated as an Immediate Repair Condition, requiring excavation for remediation and/or a pressure reduction of 20% as soon as possible, but not to exceed 5 days from the date that the situation was determined to exist, The DA service provider must immediately contact the DA Field Steward upon discovery of an Immediate Indication from the integration of data from 2 IIT surveys.

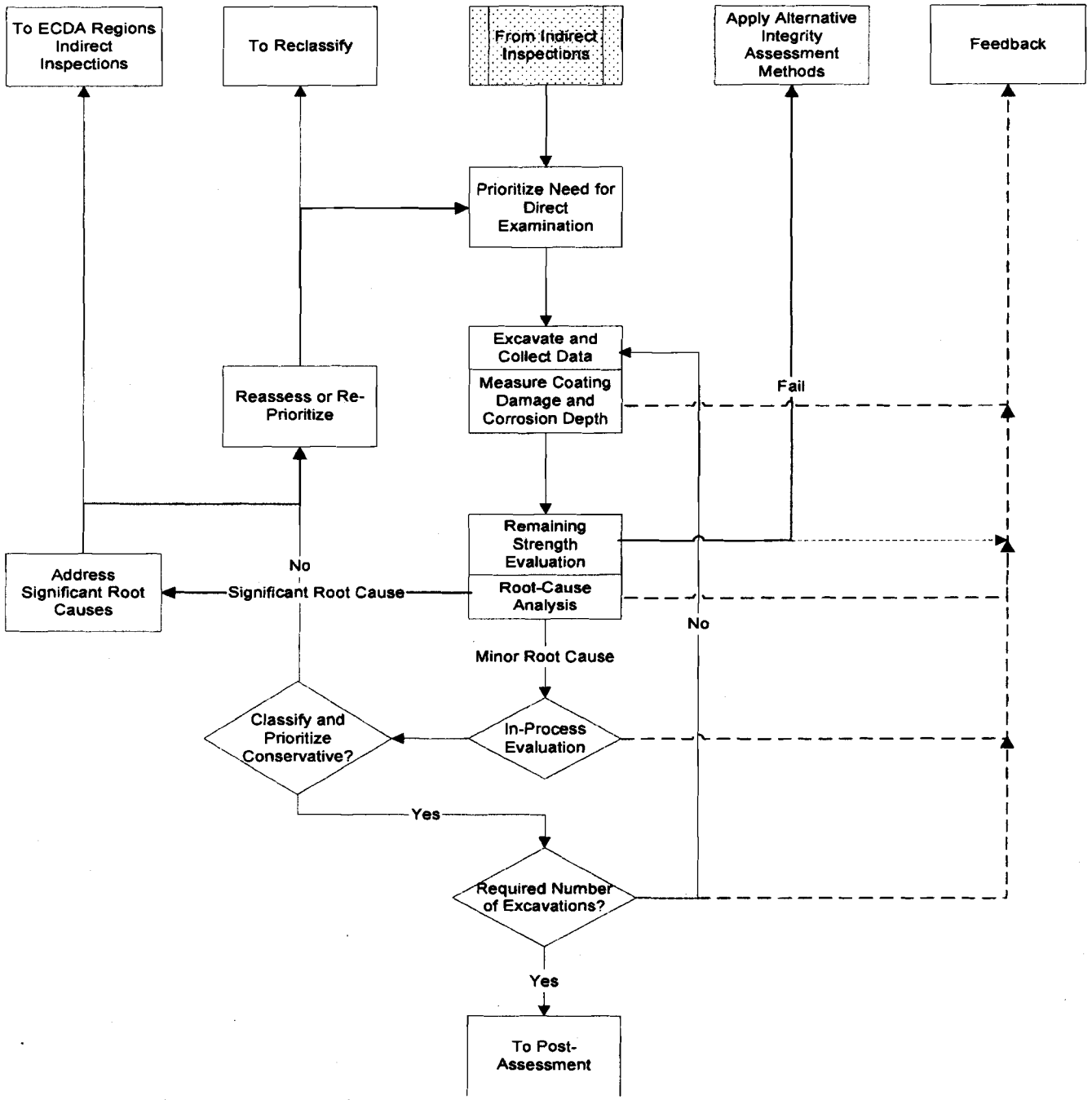
A3.2.6 Excavation Plan

An excavation plan shall be prepared by the DA service provider using the results of individual IIT surveys and an analysis with prioritization performed. A minimum of two excavations is required regardless of the results of the IIT surveys and Pre-Assessment steps. It should be noted that a DA project requiring only two excavations will be rarely encountered. At least three excavations are required for first time DA projects for each pipeline segment assessed with Direct Assessment. The DA Service Provider shall be counseled to err on the conservative side when determining excavation requirements for the Direct Examination step of a DA project.

Direct Assessment proposed excavation sites should be prioritized according to the presence of HCAs with the following priority:

1. Immediate indications inside HCAs
2. Immediate indications outside HCAs
3. Scheduled indications inside HCAs
4. Scheduled indications outside HCAs
5. Monitored indications inside HCAs
6. Monitored indications outside HCAs
7. Null digs inside HCAs
8. Null digs outside HCAs

Figure A3.3: Direct Examination Flow Chart
(continuation of Figure A3.2: Indirect Inspection Flow Chart)



(continued on Figure A3.4: Post Assessment Flow Chart)

A3.3 Direct Examinations

A3.3.1 Objectives:

- Calibrate and validate the prioritization of the IIT indications and their severity
- Collect data to assess corrosion activity at areas where it is most likely
- Measure coating damage, TPD and corrosion defects
- Evaluate remaining strength of the pipeline at any corroded or damaged pipe location
- Perform root cause analysis of corrosion and TPD encountered
- Re-Prioritize remaining indications based on results of Direct Examinations
- Evaluation of the effectiveness if the Indirect Inspection Step to determine if addional IIT surveys are required.
- Evaluation of the DA proces

A3.3.2 Required Excavations

The DA Process requires excavations to expose the pipe surface so that measurements can be made on the pipeline and in the immediate surrounding environment. A minimum of two digs is required regardless of the results of the Indirect Inspection Step and the Pre-Assessment Step. Additional guidelines for excavation are included below. The order in which excavations are made shall be determined in accordance with the results of the IIT and the site of the indication being able to affect a High Consequence Area in accordance with Integrity Management regulations.

Immediate Indications: All Immediate Indications shall be excavated during the Direct Examination Step. If Immediate Indications are re-prioritized to a lesser priority, they may be excavated in accordance with the lower priority.

Scheduled Indications: A minimum of one Scheduled Indication shall be excavated per each DA region. A minimum of two Scheduled Indications shall be excavated per DA region for the first DA project. If 20% or more metal loss is found at a Scheduled Indication, then excavation will continue on the Scheduled Indications in order of priority until at least two Scheduled Indications exhibit less than 20% metal loss. If Scheduled Indications are re-prioritized to Immediate Indications then there shall be at least one more excavation of a Scheduled Indication per each DA region.

Monitored Indications: Monitored Indications are not required to be excavated and can be either monitored or re-prioritized unless a DA region did not have any Immediate or Scheduled Indications, then at least one Monitored Indication shall be excavated for each DA region. At least 2 monitored indications shall be excavated for an initial DA project on that pipeline segment.

Initial DA Projects: Two additional null excavations are required for initial DA projects to assess the effectiveness of the DA process.

A3.3.3 Response to Indications

If Immediate Indications are indicated by the IIT surveys, the Field Steward shall be immediately notified. Excavations for severe anomalies shall be scheduled within 5 working days of the results being received by the Field Steward.

If other significant integrity conditions (other than Third Party Damage and External Corrosion) are found during the Direct Examinations, the DA service provider shall immediately notify the Field Steward. Significant integrity conditions such as significant internal corrosion, ERW seam cracks or Stress Corrosion Cracking found during the excavation process may be cause to invalidate the applicability of the DA process to the pipeline segment under investigation.

A3.3.4 Performing Excavations and Piping Examinations

Procedures for excavations, pipe coating examinations, and pipe surface examinations shall follow the requirements in Appendix 2 of this document and EMPCo's Safe Operating Practices Manual. The results from each excavation shall be recorded on EMPCo's PL-0751 Form: Piping Inspection and Remedial Action Report. The location and size of the excavation shall be expanded in length if the severity of corrosion indications extends beyond the planned excavation area.

A3.3.5 Evaluation of External Corrosion Defects and Third Party Damage

Criteria for repair of defects exposed during the Direct Examination Step shall follow the requirements of the Integrity Management Program Manual as well as EMPCo's Repair and Modifications Manual.

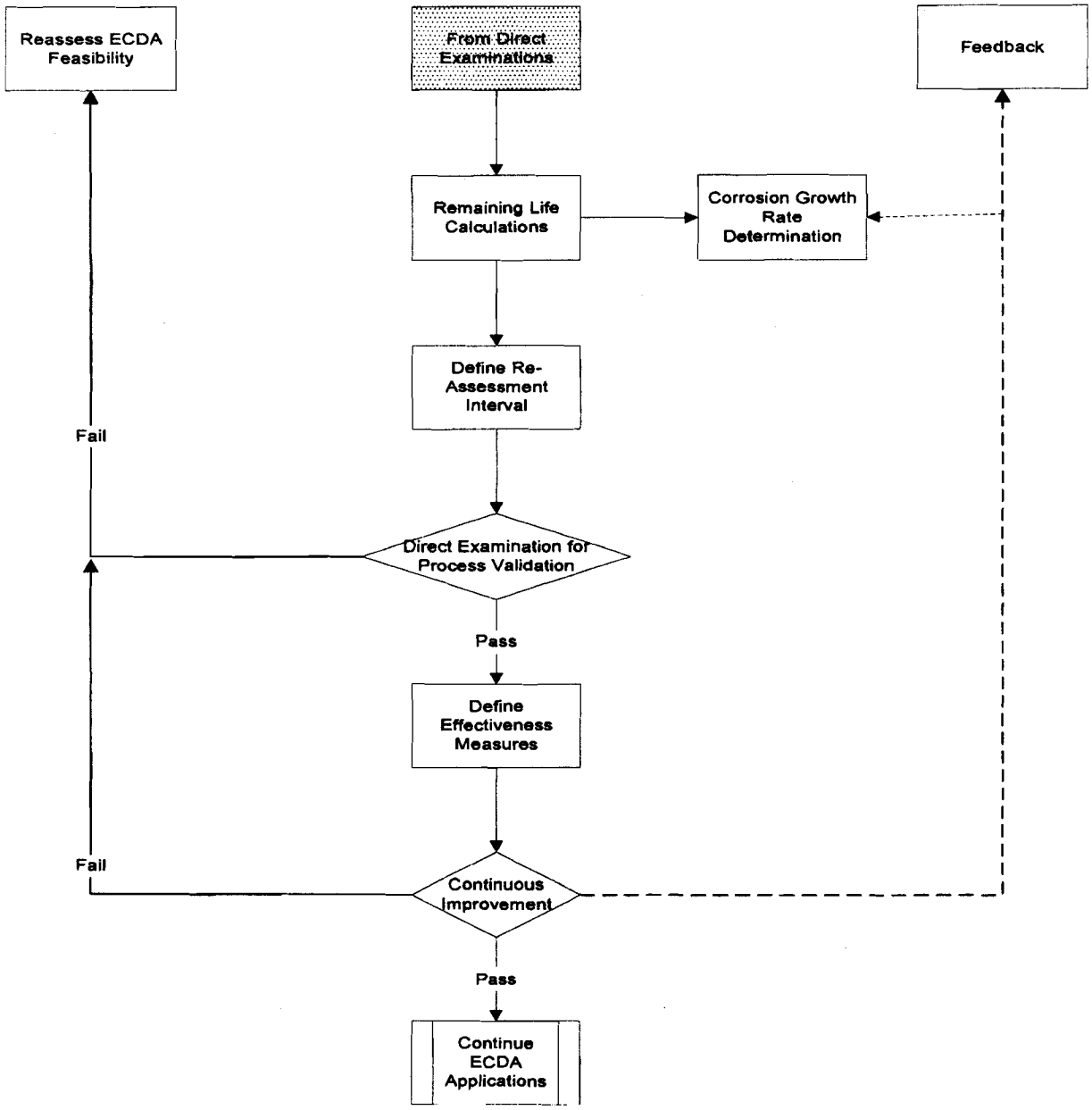
A3.3.6 Root Cause Analysis of External Corrosion Defects and Third Party Damage

The DA Service provider shall identify any existing root cause of significant corrosion activity. Root causes could include inadequate CP current, disbonded coating, interference currents from other facilities, or other causes. If the DA Service provider uncovers a root cause for which the DA process is not well suited, it shall be brought to the attention of the Field Steward at the first opportunity. The Field Steward shall determine, with the aid of the Risk ands Integrity Specialist and/or the Pipeline Integrity Specialist whether the DA process can be applied as a viable integrity Assessment for the pipeline segment under consideration.

A3.3.7 In Process Evaluation

The DA service provider shall perform an evaluation to assess the indirect inspection data and the results of the direct examinations performed to date. The evaluation shall be performed to assess the criteria used to classify the severity of the individual indications and how that criteria matched the pipe conditions found during excavations. If existing corrosion is less severe than prioritized in the IIT surveys, the DA service provider may modify the criteria and reprioritize the remaining indications. For initial DA applications, no reprioritization should be performed that downgrades the prioritization criteria. If existing corrosion is more severe than what was indicated and prioritized from the IIT surveys, then the DA service provider must modify the criteria and re-prioritize the remaining indications. The DA service provider shall immediately notify the Field Steward if re-prioritization must be performed. In addition, the need to perform additional Indirect Inspections shall be considered by the DA service provider and communicated to the Field Steward. If repeated Direct Examinations show corrosion activity that is worse than predicted even after re-classification and prioritization of indications has been performed and criteria adjusted, then the Field Steward must evaluate the viability of DA for the segment being evaluated.

Figure A3.4: Post-Assessment Flow Chart
(continued from Figure A3.3: Direct Examination Flow Chart)



A3.4 Post Assessment

A3.4.1 Objectives:

- Perform remaining life calculations
- Define Re-assessment Intervals
- Assess the overall effectiveness of the DA process
- Provide feedback to improve the DA Process
- Provide a final report of the Direct Assessment Integrity Assessment results

A3.4.2 Remaining Life Calculations

If no significant corrosion defects are found, no remaining life calculations are needed, the remaining life can be considered the same as for a new pipeline, i.e. in excess of forty years. The maximum remaining flaw size must be assumed to be as large as the most severe indication in all locations that have been excavated. If the root cause analysis determines that the most severe location is unique for the DA region, the size of the next most severe location may be used for remaining life calculation with appropriate justification. As an alternative, an operator may substitute a different value based on a statistical or more sophisticated analysis of the excavated severity(s). The corrosion growth rate shall be based upon sound engineering analysis. Measured corrosion rate data for the pipeline and applicable to the DA region under consideration may be used for the corrosion growth rate as demonstrated by the operator. If no measured corrosion rate has been established for the pipeline under consideration, published data should be used in accordance with NACE recommended practices.

Remaining life of the maximum remaining flaw shall be estimated using sound engineering analysis. One method per NACE RP0502-2002 is as follows:

$RL = C \times SM \times [T / GR]$ where:

RL = Remaining Life (years)

C = Calibration Factor = 0.85 (dimensionless)

SM = Safety Margin = Failure pressure ratio - MAOP ratio (dimensionless)

Failure pressure ratio = Calculated failure pressure/yield pressure (dimensionless)

MAOP ratio = MAOP/yield pressure (dimensionless)
T= Nominal wall thickness (inches)
GR = Growth rate (inches / year)

Note: this method of calculating expected remaining life is based on corrosion that occurs continuously and on typical sizes and geometries of corrosion defects and is considered to be a conservative method. An example published corrosion Growth Rate is shown in table A3.6

Table A3.6: Corrosion Rates vs Soil Resistivity per ASME B31.8S

Corrosion Rate (mils per year)	Soil Resistivity (ohm-cm)
3	> 15,000 + no active corrosion
6	1,000 - 15,000 and/or active corrosion
12	<1,000 (worst case)

When other data is not available, a pitting rate of 16 mils per year is recommended for determining re-inspection intervals per NACE RP0502. This rate represents the upper 80% confidence level of maximum pitting rates for long term (up to 17 year duration) underground corrosion tests of bare steel pipe coupons without CP in a variety of soils including native and nonnative backfill.
An example of estimating corrosion growth rate is as follows: A pipeline under cathodic protection in soil with a resistivity measured between 1500 and 2500 ohm-cm would be assumed to have a worst case corrosion rate at 6 mils per year, unless data collected in the field during the direct assessment phase of a DA project indicated a corrosion growth rate at 4 mils per year in the same DA region. The maximum reassessment interval for each DA region shall be taken as one-half the calculated remaining life. The maximum reassessment interval is limited by regulation and at the time of this document was at a maximum of five years for a hazardous liquid pipeline and at 10 years for a natural gas pipeline. Different DA regions may have different reassessment intervals based on variations in expected growth rates and maximum corrosion defect encountered during the assessment. All scheduled indications should be excavated and repaired prior to the scheduled reassessment date.

A3.4.3 Assessment of Direct Assessment Effectiveness

Direct Assessment is a continuous improvement process through which an operator can identify and address locations at which corrosion activity has occurred, is occurring, or could occur in the future. At least one additional excavation should be performed at a randomly selected location where no indications have been detected with IIT surveys. This "null hypothesis" excavation should yield no indications as a validation that no corrosion or Third Party Damage was found where the process and inspections predicted that no corrosion or TPD would occur. In this way the process is made to prove the positive indication as well as a negative indication. If significant corrosion or TPD is found at the "null hypothesis" site, a process re-evaluation is in order. For the initial DA application to a pipeline segment, two additional excavations are required to be performed in order to further validate that the DA process is applicable and has been implemented successfully. If conditions are found that are more severe than that predicted during the DA process, such that an acceptable reassessment interval is not achieved, the process should be re-evaluated and either repeated or a different assessment method chosen. Sections IV and V of the first part of this document delineate measurements and verification steps as well as continuous improvement items to be implemented as a part of the DA program within EMPCo.

A3.4.4 Feedback

As a continual improvement process, the DA Process is uniquely designed to provide feedback on the performance of both individual assessment evaluations as well as program evaluation. Each flowchart of each step of the process has a feedback loop built into the process such that continuous improvement in each step of the process is facilitated. The DA process is also built to continuously validate each step of the process and recycle steps as appropriate to continuously validate itself during the execution of the process in assessing pipeline integrity. For example, the Indirect Assessment Step provides feedback on performance of the IIT methods selected back to the Pre-Assessment Step in order to further improve IIT selection during the Pre-Assessment Step. The Direct Examination Step provides feedback on performance of the IIT methods and selection of severity criteria back to the Indirect Inspection Step and the Pre-Assessment Step. Post-Assessment also provides feedback on performance of the Direct Examination Step to the Indirect Inspection Step and the Pre-Assessment Step. In this way the process continuously attempts to validate itself as an appropriate integrity assessment method for the pipeline being assessed as well as the DA program overall and it's applicability to assessment of the External Corrosion and Third Party Damage threats to pipeline integrity.

A3.4.5 Final Report

The records and deliverables to be included in the Final Direct Assessment Report by the DA service provider include the following:

- Cover letter to Field Steward requesting approval of DA results
- Pre-Assessment Documentation
  - Data Elements collected for pre-assessment
  - Methods and procedures used to integrate the data collected and to determine which IIT methods can and cannot be used
  - Methods and procedures used to select the IIT.
  - Characteristics and boundaries of DA regions and the applicable IIT methods chosen for each DA region
- Indirect Inspection Documentation
  - Geographically referenced locations of the beginning and end points of each DA region and each fixed point used for determining the location of each measurement
  - Date, weather, and soil conditions under which each IIT survey was performed
  - IIT survey results in sufficient resolution to identify the location of each indication
  - Procedures for aligning data from the IIT surveys and expected alignment errors for each IIT
  - Procedures for defining the criteria to be used in prioritizing the severity of the indications
- Direct Examination Documentation
  - Complete inspection reports for each excavation performed
  - Procedures and criteria used to prioritize the IIT survey results
  - Data collected before, during, and after excavation of IIT indications including:
    - Pipe coating examination results
    - Metal loss anomaly measurements
    - Data used to identify other areas that may be subject to corrosion
    - Data used to estimate corrosion growth rates
    - Results of any root-cause analyses
    - Description and the reason for any re-prioritization performed
    - NDT performed and results of NDT examinations
- Post-Assessment Documentation
  - Remaining life calculations
  - Maximum remaining flaw size determinations
  - Remaining strength evaluation of flaws discovered during DA
  - Corrosion growth rate determinations
  - Method of estimating remaining life
  - Results of remaining life calculations
  - Reassessment intervals and scheduled activities
  - Criteria used to assess DA effectiveness and results from assessment
  - Data from periodic assessments
  - Recommendations for Scheduled and Monitored indication remediations with timeframes proposed for implementation
  - Preventive and mitigative measures considered for improvements to pipeline integrity
  - Feedback items including:
    - Assessment of criteria used in each step of the DA process
    - Modifications of criteria

The Final Report from the DA service provider shall be submitted to the Field Steward for review and approval with comments no later than 90 days after completion of all field work related to the Direct Examinations (other than

ongoing repair activities) has been completed. Hard copies or electronic copies of the Final Report shall be provided in accordance with the Field Steward's preference.

A3.4.6: Integration of DA Results Into IMP Activities

After the DA service provider has made delivery of the final report, EMPCO's Risk and Integrity Specialist is charged with integration of the integrity assessment test results with all other integrity data in order to prepare a Repair Plan for any anomalies remaining to be remediated and then perform Preventive and Mitigative Analysis and prepare P&M Activites in accordance with EMPCo's IMP Manual. RIS's are to pay particular attention to P&M Activities to prevent TPD if significant TPD is discovered during the DA of the pipeline segment.

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 10, 2007

Mr. Patrick Doolan
Vice President
ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

RE: Request for Time Extension - Response to Notice of Amendment (NOA) letter dated August 2, 2007, for CPF 4-2007-5030M

Dear Mr. Doolan:

ExxonMobil Pipeline Company submitted a letter dated September 04, 2007 regarding the referenced NOA requesting a time extension until October 31, 2007 for the actions required for amending the deficient procedures noted in the referenced NOA.

We have reviewed your request and grant the extension for all issues in the NOA until October 31, 2007 in order to ensure that there is adequate time for revisions to the processes and procedures and appropriate internal technical review of the revisions noted in **CPF 4-2007-5030M**.

Sincerely,

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

Pat Doolan
Vice President
Southern Operations

ExxonMobil
Pipeline

September 4, 2007

VIA FACSIMILE (713-272-2859) AND
CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Notice of Amendment CPF No. 4-2007-5030M
Warning Letter CPF No. 4-2007-5029W

Dear Mr. Seeley:

Representatives of the Office of Pipeline Safety conducted a comprehensive inspection of ExxonMobil Pipeline Company's (EMPCo) Integrity Management Program (IMP) during April 9-13, 2007; April 23-27, 2007; and May 7, 2007. Pursuant to this inspection, on August 7, 2007, EMPCo received a Notice of Amendment (NOA) and a Warning Letter from the Pipeline and Hazardous Materials Safety Administration (PHMSA). This letter is EMPCo's initial response to the NOA. A response to the warning letter items, although not required, is also included herein.

We first want to assure you that EMPCo is committed to continuous improvement of a thorough and comprehensive IMP that is fully integrated with ongoing operational processes. After review of the recommended amendments, our plan forward for amending our program is outlined below. As required by 49 CFR §190.237 EMPCo is providing to the OPS written explanation of our plan regarding the item noted in the NOA.

The NOA identified one (1) area for amendment. This item is outlined in detail below, followed by EMPCo's response and plans to address the recommended improvement.

Item 1.
§195.452 Pipeline integrity management in high consequence areas
(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
(5) Assessment Methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(iii) External corrosion direct assessment in accordance with §195.588

§195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section 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.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan the includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include -

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment

A. *EMPCo must modify their ECDA procedures regarding indication severity classification in the ECDA Plan Table A3.3 which does not appear to be as conservative as NACE RP-0502-2002 Table 3. NACE RP 0502-2002 table 3 gives example severity criteria for several indirect inspection methods.*

B. *EMPCo must modify their ECDA procedures to ensure that more restrictive criteria in addition to those required by NACE RP-0502-2002 are applied when conducting ECDA direct examination for the first time on a pipeline segment per §195.588. EMPCo has indicated that additional excavations will be conducted when conducting ECDA direct examinations for the first time on a pipeline segment; however, these additional excavations are a requirement of NACE RP-0502-2002 and, therefore, the IMP rule. As such, the additional excavations do not represent "more restrictive criteria" as described in §195.588.*

EMPCo Response:
EMPCo will modify the ECDA process to include indication severity classifications which are as conservative as NACE RP-0502-2002 Table 3. Furthermore, EMPCo will modify the ECDA procedures to apply criteria more restrictive that that required by NACE RP-0502-2002 for first time ECDA's. EMPCo expects to complete these modifications to our process and procedures and submit the revised documentation to PHMSA no later than October 31, 2007.

In addition to the Notice of Amendment Letter, EMPCo also received a Warning Letter of probable violations of the Pipeline Safety Regulations. The items cited, and EMPCo's corrective plans for each are cited below:

1. **§195.452 Pipeline integrity management in high consequence areas.**

(h) What actions must an operator tale to address integrity issues?

(3) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the scheduled and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.

ExxonMobil Pipeline Company (EMPCO) documented a decision to not repair an anomaly on the Grand Isle Block 22L to Grand Isle Terminal segment meeting 180-day rule repair criteria without notifying PHMSA or obtaining regulatory relief from PHMSA through the waiver process. The inspection team noted that EMPC developed draft material for technical justification that indicated the segment of pipeline containing the anomaly could not affect an HCA. However, formal re-evaluation of whether the segment could affect an HCA was not fully pursued and documented in sufficient detail to establish this position.

PHMSA recognizes that some operators used methods with conservative assumptions in identifying which pipeline segments can affect HCA's to meet the initial compliance deadline. Refinement of these "could affect segments", potentially changing the boundaries of the identified segments, may occur as more detailed analyses are performed. This refinement process could result in conclusions that some segments (or portions of segments) identified by the initial deadline cannot affect an HCA. PHMSA expects operators to document their justification for any such elimination of an identified segment, and may review the technical basis for these changes during inspections.

Operators should not, however, apply refinements which impact the determination of whether a segment can affect an HCA once the process of conducting an integrity assessment for that segment has begun. The integrity assessment results must be evaluated, and repairs required by the criteria of paragraph (h) must be performed, for the entire segment as defined prior to conduct of the assessment. The boundaries of the segment can be reconsidered after conclusion of an integrity assessment and repair process.

EMPCo response:
The repair of this anomaly was completed on August 30, 2007

2. §195.49 Annual report

Beginning no later than June 15, 2005, each operator must annually complete and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operator 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 encourages, but not required, to file an annual report by June 15, 2004, for calendar year 2003.

Included in the integrity assessment data reviewed by the Inspection Team were anomalies that met immediate repair criteria and were remediated as part of confirmatory digs within a short

Included in the integrity assessment data reviewed by the Inspection Team were anomalies that met immediate repair criteria and were remediated as part of confirmatory digs within a short period of time but were not classified as immediate conditions. The classification of these anomalies as "confirmatory digs" rather than "immediate conditions" in EMPCo's internal tracking system results in a failure to accurately trend and report anomalies that meet the immediate repair criteria. EMPCo should ensure that immediate conditions are identified as such and included in data that is required to be annually transmitted to PHMSA.

Response:
The EMPCo Integrity Management Program manual will be updated to provide specific guidance regarding inclusion of confirmatory digs as part of the overall immediate repair category, as appropriate. EMPCo personnel responsible for repair tracking and final repair plan determination have been apprised of this issue.

EMPCo is committed to having a robust and continuously improving integrity management program. We appreciate your input.

If you have any questions about the information presented in this letter, or desire additional information, please contact Johnita D. Jones @ 512-306-7981 or Kevin Badgett at 713-656-2651.

Patrick T Doolan
Operations Manager
ExxonMobil Pipeline Company

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

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 2, 2007

Mr. Patrick Doolan
Vice President
ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

CPF 4-2007-5030M

Dear Mr. Doolan:

During April 9-13, 2007; April 23-27, 2007; and May 7, 2007 representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected ExxonMobil Pipeline Company (EMPCo) procedures for Hazardous Liquid Integrity Management in Houston, TX.

On the basis of the inspection, PHMSA has identified apparent inadequacies found within EMPCo's plans or procedures, as described below:

1. **§195.452 Pipeline integrity management in high consequence areas**

   (j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

   (5) Assessment methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

   (iii) External corrosion direct assessment in accordance with §195.588

   §195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section 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.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see § 195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment.

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include--

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment

A. EMPCo must modify their ECDA procedures regarding indication severity classification in the ECDA Plan Table A3.3 which does not appear to be as conservative as NACE RP-0502-2002 Table 3. NACE RP-0502-2002 Table 3 gives example severity criteria for several indirect inspection methods.

B. EMPCo must modify their ECDA procedures to ensure that more restrictive criteria in addition to those required by NACE RP-0502-2002 are applied when conducting ECDA direct examination for the first time on a pipeline segment per §195.588. EMPCo has indicated that additional excavations will be conducted when conducting ECDA direct examinations for the first time on a pipeline segment; however, these additional excavations are a requirement of NACE RP-0502-2002 and, therefore, the IMP Rule. As such, the additional excavations do not represent "more restrictive criteria" as described in §195.588.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2007-5030M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

FILE COPY

ABBREVIATED PROCEDURES
STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report	Post Inspection Memorandum
Inspector/Submit Date: 10/2/06	**Inspector/Submit Date:** 10/2/06 **Peer Review/Date:** 10/5/06 **Director Approval/Date:**

Need VL, NAA & PCO

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator: ExxonMobil Pipeline Company	**OPID #:** 4906
Name of Unit(s): Silver Tip Pipeline	**Unit # (s):** 1255
Records Location: Bridger, MT	
Unit Type & Commodity: Crude Oil	
Inspection Type: Standard	**Inspection Date(s):** 6/20-22/2006
PHMSA Representative(s): Jerry Davis	**AFO Days:** 3.0

Summary:

With the addition of the inter-tie with Terasen's Express pipeline at Edgar ExxonMobil has completed a re-analysis of the Silvertip pipeline's hydraulics. This analysis has resulted in all automated valves being retrofitted with a faster acting bypass valve to prevent over-pressuring the pipeline during valve closures. Originally the automatic by pass valves were Flex Flow. This is an axial pressure relief valve that senses upstream pressures and opens at a preset pressure. These new valves now use bottled nitrogen to open the valve and not the upstream pressure, so they are more responsive.

A new pump station was added at Edgar that takes crude oil stored at Terasen's Edgar station's breakout tanks and transfers it to the Silvertip pipeline for transportation into the Billings ExxonMobil refinery.

CP records show a low spot below 850 on at MP 54.800. In August EMPCo is going to dig the road crossing at MP 54.8 which is a low CP spot.

County Rd Xing next to Peterson farm 880 mV

Bridger Station west 1240 mV on.

Bridger Station inlet 1347 mV on.

Upstream Yellowstone River Xing MOV, in Billings, 1340 mV on. This valve was retrofitted with a bypass pressure relief valve that resulted from the surge analysis done for the Silvertip pipeline after the Edgar station came on line. This valve had no bypass prior to the surge analysis.

MP 15.58 just upstream of the proposed location of a Walmart in Laurel, 1663 mV on.

Casing at 15.58 -100 mV.

Inlet Edgar Station, 782 mV. Appears that the mag anode is not connected to the pipe, there was no jumper in the CP junction box. I will check to see if this issue has been resolved in the near future.

MP 134.171, Edgar Station to Silvertip junction on mainline, 1501 mV on, , casing 948

Noted that casing at future Walmart site has a low reading of -.17 V. Appears to be an influence issue.

They used Armor Plate wrap for repairs. Number of wraps depended on the depth of the pit. CoreCal was the methodology used for determining remaining strength, it is modified B31G.

Findings:

WL

§195.410 Right-of-Way Markers

There were not pipeline markers lacking at the Peterson road crossing, MP 54.8.

WL

§195.402(c)/§195.422 & §195.214(a) Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.

EMPCo's Pipeline Welding Manual and DOT Liquids Manual procedures do not reference the specific edition of API 1104 that is currently accepted under Part 195. *See Attachment #1.*

ABBREVIATED PROCEDURES
STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Findings:

NOA

§195.222(b) Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.

EMPCo's Pipeline Welding Manual procedures state that a welder may not weld with a particular welding process unless that welder has welded and had an acceptable NDT using that process within the previous 12 months. *See Attachment #2.*

NOA

§195.402(c)/ §195.422/ §195.228/§195.234 Do procedures require welds to be nondestructively tested to ensure their acceptability according to Section 9 of API 1104 (19th) and as per §195.228(b) and per the requirements of §195.234 in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.

EMPCo's DOT Liquids Manual NDT procedure references §195.228 and not Section 9 of API 1104. *See Attachment #3.*

NOA

§195.402(a)/ §195.434 Operator must maintain signs visible to the public around each pumping station and breakout tank area.

EMPCo's DOT Liquids Manual signage procedure only calls for signage around breakout tanks and meters and valves and other critical locations, but not specifically pump stations. *See Attachment #4..*

NOA

§195.569 Examination of Exposed Portions of Buried Pipelines.

Though EMPCo's One-Call Procedures reference a form to complete if the pipeline is uncovered EMPCo's DOT Liquids Manual Exposed Pipe procedures for the examination of exposed portions of pipelines does not reference the form that EMPCo employees use when implementing this function. *See Attachment #5.*

NOA

§195.573 b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;

EMPCo corrosion procedures do not give guidance to cathodically protect bare pipe. EMPCo's DOT Liquids Manual though does discuss the possibility that EMPCo may have bare pipe.

WL

§195.230 Welds: Repair or removal of defects.

Weld number S129's disposition was unaccounted for on the Edgar project.

WL

§195.402(a) Annual Review of O&M Manual (1 per yr/15 months)

EMPCo records only show the date of the latest manual review and not the last 2 manual reviews. *See Attachment #6*

PCO if PQR not received by the time the violation letter is written

§195.404(c)(1) Pipe Repairs (maintain for useful pipe life)

Records for dig number 465 have no PQR for the in-service welding procedure that was used. I have been told that they are getting this PQR from Houston.

PCO if EMPCo does not provide the requested CP plot.

§195.589(c)/ §195.573(a)(1) External Corrosion Control, Protected Pipelines Annual CP tests (1 per yr/15 months)

EMPCo cathodic protection monitoring procedures require that the annual monitoring survey be plotted with the previous 3 years of survey data to determine if there is a deficiency in cathodic protection. EMPCo records only had the previous two years of data plotted with the annual survey. I requested a plot of 2005 along with previous 3 years data to determine if IR drop accounted for.

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Name of Operator: ExxonMobil Pipeline Company (EMPCo)	
OP ID No. [1]	**Unit ID No.** [1]
H.Q. Address:	**System/Unit Name & Address:** [1]
3225 Gallows Rd Fairfax, VA 22037 I have emailed Claude Allen on this apparent change.	110 Cemetery Road Bridger, MT 59014
Co. Official: Jimmy James Operations Manger- Northern	**Activity Record ID#:** 116697
Phone No.: 703-846-6692	**Phone No.:** (406) 662-3569
Fax No.: 703-846-6904	**Fax No.:**
Emergency Phone No.: 800-537-5200	**Emergency Phone No.:** 800-537-5200

Persons Interviewed	Titles	Phone No.
Thad Massengale	Safety Health & Envir. P/L Safety Advisor	713-656-2258
Robert D. Foote	Montana Area Superintendent	406-657-5400
James A. Althoff	Senior Operations Tech. A	406-662-3569
Steve Everett	Technican	406-662-3569
Dave Ort	CP Tech	661-763-7621

PHMSA Representative(s) [1] **Inspection Date(s)** [1]

Company System Maps (copies for Region Files):

Unit Description:

The 12.75" pipeline originates at the Silvertip pump station (Elk Basin field) in Carbon County, MT and terminates at the ExxonMobil refinery in Billings, MT. This pipeline is made up of approximately 22 miles of 12 3/4 inch diameter, .250 wt. X-42 and X-35 ERW pipe installed in 1949 and 1954, approximately 44.5 miles of 12 3/4 inch diameter, .312 wt. X-35 ERW pipe installed in 1949 and 1957, 2.5 miles of 12 3/4 inch diameter .375 inch pipe installed in the 50's and 60's. The balance of the 69 plus mile long pipeline is made up of both ERW and SMS 8 5/8 inch, .322 wt pipe and 12 3/4 inch .375 and .5 inch wt pipe. This system includes a pump station with 5 breakout tanks at the Silver Tip station, and a booster station at Bridger, MT. The line delivers crude oil to both the ConocoPhillips refinery and the ExxonMobil refinery in Billings, MT. A Cenex pipeline booster station, located in Laurel, MT, delivers crude oil from Cenex Pipeline's Front Range Pipeline. In 2005 there was a tie-in made to the Terasen Pipeline's Express pipeline at Terasens's Edgar station, MT. This tie-in consists of two ½ mile long 12 3/4-inch, X-52, .312 wt pipelines from the Silvertip pipeline to the Edgar station. At the Edgar Station ExxonMobil installed 2 pumps to receive crude from Terasen's breakout tanks. This pipeline now receives crude from the Express pipeline, the Silvertip station or from Cenex's Front Range pipeline. Crude from the Express pipeline is kept separate from all other flows, it is considered a syncrude. Operating pressure ranges from 400-900 psi, depending on demand and location.

Portion of Unit Inspected [1]

I inspected records and some procedures at the Bridger office. I inspected some locations along the ROW where CP monitoring indicated a low CP reading, inspected the upstream Clarks Fork MOV, the Bridger station, the terminal facility at the ExxonMobil

[1] Information not required if included on page 1.

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refinery in Billings, the upstream Yellowstone River MOV in Billings, the King Avenue MDT construction project that crosses the Silvertip pipeline, the Horse Palace replacement project site, the site of a proposed Walmart in Laurel, MT where the Silvertip pipeline crosses under the proposed parking lot, the Cenex Front range tie-in at the Cenex refinery in Laurel, MT, the upstream Yellowstone MOV in Laurel, the Edgar station and tie-in, and the Elbow creek upstream manual block valve.
Completed IM field verification. See the attached Hazardous Liquid IMP Field Verification Form.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/14/01 and 03/14/06.

Western Region: Conducted abbreviated procedures inspection on 195 Operations and Maintenance Items that changed since the last inspection. Items that were included in the operator's O & M Manual at the previous inspection (as per date entered below) may be marked with a "1" in the N/C column to reflect the standard "Note 1" in the Comments blocks. Records And Field Item Will Be Inspected As Per A Routine Inspection.

(check one below and enter appropriate date)

	Team inspection was performed (Within the past five years.) or,	Date:	2002
	Western Region Inspector reviewed the O & M Manual (Since the last yearly review of the manual by the operator.)	Date:	

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
*	.49	Complete Annual Report and submit DOT form RSPA 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. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.	✓			
*	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02			✓	

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
* .402(c)/ .422	.214(a)	Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04. Need to reference the edition, their O&M manual uses. Their procedures state the correct section but not which edition. This is a minor issue and I advised them that they need to reference the DOT referenced edition.		✓		

ABBREVIATED PROCEDURES
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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04. See above.		✓		
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03. O&M manual good but welding manual states 12 months for liquids welders.		✓		
		Nondestructive Testing Procedures				
.402(c)/ .422*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **§195.228(b)** and per the requirements of **§195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04. References 195.228 and not API 1104.		✓		

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	✓			

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
.402(a) *	.403(a)(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. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	✓			

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

		SIGN PROCEDURES	S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area. Signage procedure only calls other breakout tanks and meters and valves and other critical locations, not specifically pump stations		✓		
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	✓			

Comments:

ABBREVIATED PROCEDURES
STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Establishing a continuing educational program (in English and other pertinent languages) to better inform the public in how to recognize and report potential hazardous liquid or carbon dioxide pipeline emergencies [prior to June 20, 2006]	✓			
		Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance? Self Verification with supervisor signature for Bridger, but Dave is the CP tech responsible for maintaining CP compliance and he is OQed every two years and is also NACE Technologist.	✓			
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.	✓			
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;	✓			
		2) Is a segment that is relocated, replaced, or substantially altered?	✓			
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance. This procedure referenced .559 but the procedure also included the requirements of 195.559	✓			
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.	✓			
		b. All coating damage discovered must be repaired.	✓			
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**	✓			
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or	✓			

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
		2) Is a segment that is relocated, replaced, or substantially altered?	✓			
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.	✓			
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.	✓			
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.	✓			
	.567	Test leads installation and maintenance.	✓			
	.569	Examination of Exposed Portions of Buried Pipelines. Needs to reference the form that is used. The one-call procedure does but not the 569 procedure.		✓		
	.571	Cathodic protection 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 Standard RP0169-96** (incorporated by reference). **They compare the last 3 years readings and if significant drop then they must investigate. Criteria are 850 on or 100 mV. This is from the 2003 hearing with Kevin Garrity. This falls under the other under 6.2 of RPO 169.**	✓			
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.	✓			
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.	✓			
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify 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 RP0169-96.**	✓			
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment **Their O&M manual discusses bare pipe and refers to FIMMS CP Management procedure but this procedure does not discuss bare pipe inspection procedures.**		✓		
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**	✓			
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**	✓			
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)	✓			
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.	✓			
	.575	Are there adequate provisions for electrical isolations?	✓			
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures. They reference NACE RPO 169 2002 section 7 design which states this so appears to be ok.	✓			
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.	✓			
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.	✓			

ABBREVIATED PROCEDURES
STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**	✓			
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.	✓			
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).	✓			
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**	✓			
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**	✓			
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?	✓			
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?	✓			
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**	✓			
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).	✓			

Comments:

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations	✓			
.262	Station Safety Devices	✓			
.308	Pre-pressure Testing Pipe - Marking and Inventory They have none			✓	
.403	Supervisor Knowledge of Emergency Response Procedures	✓			
.410	Right-of-Way Markers Markers lacking at the Peterson road crossing MP 54.8 that is due for excavation.		✓		
.412	ROW/Crossing Under Navigable Waters	✓			
.420	Valve Maintenance	✓			
.420	Valve Protection from Unauthorized Operation and Vandalism	✓			
.426	Scraper and Sphere Facilities and Launchers	✓			
.428	Pressure Limiting Devices	✓			
.428	Relief Valves - Location - Pressure Settings - Maintenance	✓			
.428	Pressure Controllers	✓			
.430	Fire Fighting Equipment	✓			
.432	Breakout Tanks We did not inspect the Silvertip station were the breakout tanks reside.				✓
.434	Signs - Pumping Stations - Breakout Tanks	✓			
.436	Security - Pumping Stations - Breakout Tanks	✓			
.438	No Smoking Signs	✓			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form I did an OQ verification during the last inspection cycle.			✓	

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	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	✓			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	✓			
.575	Electrical Isolation; shorted casings	✓			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	✓			

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			✓	
.5(c)	Pipeline Records (Life of System)			✓	
	Pipeline Investigations			✓	
	Pipeline Testing			✓	
	Pipeline Repairs			✓	
	Pipeline Replacements			✓	
	Pipeline Alterations			✓	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	✓			
.52	Telephonic Reports to NRC (800-424-8802) No spills			✓	
.54(a)	Written Accident Reports (DOT Form 7000-1)			✓	
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)			✓	
.56	Safety Related Conditions They did a pressure reduction because of an indeterminate condition which they thought may have been SCC, but Kiefner's investigation determined it to be surface delaminations, there was no SRC.			✓	
.57	Offshore Pipeline Condition Reports None			✓	
.59	Abandoned Underwater Facility Reports None.			✓	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	✓			
.214(b)	Test Results to Qualify Welding Procedures Appears they use the welder qualification as weld qualification. The tests used 7010 for the root but the procedure called for 6010, look at 1104 for metal class. Did not have PQR for the in-service weld. They are getting this.	✓			
.222	Welder Qualification. Qualification on a 45 angle I think this allows for any angle.	✓			
.234(b)	Nondestructive Technician Qualification	✓			
.589	Cathodic Protection	✓			
.266	Construction Records	✓			
.266(a)	Total Number of Girth Welds	✓			
	Number of Welds Inspected by NDT 100% appears so.	✓			
	Number of Welds Rejected	✓			
	Disposition of each Weld Rejected One weld disposition unaccounted for on the Horse Palace project, Weld S129.		✓		

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	✓			
.266(c)	Location of each Crossing with another Pipeline	✓			
.266(d)	Location of each buried Utility Crossing	✓			
.266(e)	Location of Overhead Crossings	✓			
.266(f)	Location of each Valve and Test Station	✓			
	PRESSURE TESTING				
.310	Pipeline Test Record	✓			
.305(b)	Manufacturer Testing of Components	✓			
.308	Records of Pre-tested Pipe				✓
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**) The records of previous reviews are not consistently kept, only the latest is kept on the manual data base. Their records should show last 2 years reviews.		✓		
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions Consider all areas as immediate response area.	✓			
.402(c)(10)	Abandonment of Facilities			✓	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	✓			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures They do an annual LOI review by all employees during a training session. I made a suggestion that they modify the form to include what action if any resulted in the reviews and the follow-up actions.	✓			
.402(d)(1)	Response to Abnormal Pipeline Operations	✓			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures They do an annual LOI review by all employees during a training session.	✓			
.402(e)(1)	Notices which require immediate response			✓	
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency			✓	
.402(e)(9)	Post Accident Reviews			✓	
.403(a)	Emergency Response Personnel Training Program	✓			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**) They have a data base that notifies employees quarterly of the emergency response training they need to take. It is called Mocking Bird.	✓			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures See above.	✓			
.404(a)(1)	Maps or Records of Pipeline System	✓			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines They are in the process of redrawing the entire set of alignment sheets as CADD sheets which will show the Edgar tie in.	✓			
.404(a)(3)	MOP of each Pipeline They have a listing of each pipe segment but they call out 960 psig in Ops manual.	✓			
.404(a)(4)	Pipeline Specifications	✓			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs) They keep electronic records on their SCADA system which are archived at 6 months. They gave me Dec 7 2003 pressure records for all stations. Got it within 4 hours of request.	✓			
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs) OCC Trouble Log	✓			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life) Dig number 465 there is no PQR for procedure they are getting from Houston.		✓		

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr) Not checked.				✓
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	✓			
.406(a)	Establishing the MOP	✓			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions. OCC Trouble Log	✓			
.412(a)	Inspection of the ROW	✓			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways			✓	
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			✓	
.420(b)	Inspection of Mainline Valves Inspections are completed twice per year and maintenance once per year.	✓			
.428(a)	Insp. of Overpress. Safety Devices (1 per yr/15 months non-HVL; 2 per yr/7½ months HVL) Several Flex Flow valves were replaced with Daniels valves with a more rapid reponse and higher Cv factor allowing set pressures to be increased.	✓			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE 5 yrs).			✓	
.428(d)	Inspection of Overfill Systems (1 per yr/15 months non-HVL; 2 per yr/7½ months HVL)	✓			
.430	Inspection of Fire Fighting Equipment	✓			
.432	Inspection of Breakout Tanks (1 per yr/15 months or per API 510 or 653).	✓			
.440	Public Education/Awareness Program	✓			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	✓			
.442(c)(2)	Notification of Public/Excavators	✓			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	✓			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	✓			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	✓			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	✓			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (1 per yr/15 months) I requested a plot of 2005 along with previous 3 years data, as required in their procedures, to determine if IR drop accounted for.		✓		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator) There was a close interval done at the area of low reading above using on readings only.	✓			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (1 per 3 cal yr/39 months)			✓	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✓			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks Tank measurements on 4 sides. Nothing below 850 on but there is no comparision with previous 3 years data.	✓			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h). They are going to dig the MP 54.8 low spot in August.	✓			
.589(c)/.575	Electrical isolation inspection and testing The old highway 10 casing at MP 16.844 is 104 mV difference between pipe. Was gel filled in 1999.	✓			
.589(c)/.577	Testing for Interference Currents None determined from the annual monitoring.	✓			
.589(c)/.579(a)	Corrosive effect investigation They have limits tested for various constituents.	✓			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (2 per yr/7½ months)	✓			

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	✓			
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)** Need to include follow-up action comment on the form. Inspections completed in 2003 and they have begun the 2006 ones.	✓			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG They used Armor Plate wrap for repairs. Number of wraps depended on the depth of the pit. CoreCal was the methodogy used for determining remaining strength, it is modified B31G.	✓			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	✓			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	✓			

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]			✓
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			✓
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			✓
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]			✓
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]			✓

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

I did not review the Oil Spill Response Plan. I reviewed this during the last inspection. There had been an issue with Washington reviewing the plan at that time.

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

Number	Date	Subject
ADB-04-02	July 22, 2004	Pipeline Safety: Semi-Annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management
ADB-04-03	August 18, 2004	Pipeline Safety: Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities
ADB-04-04	September 23, 2004	Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan
ADB-04-05	November 26, 2004	Pipeline Safety: Operator Qualification Requirements
ADB-05-01	January 21, 2005	Pipeline Safety: Semi-Annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management
ADB-05-02	April 6, 2005	Pipeline Safety: Strapping Table Calibration for Pipeline Breakout Tank Operators
ADB-05-03	May 23, 2005	Pipeline Safety: Planning for Coordination of Emergency Response to Pipeline Emergencies
ADB-05-04	July 29, 2005	Integrity Management Notifications for Gas Transmission Lines
ADB-05-05	August 10, 2005	Pipeline Safety Advisory Bulletin - Inspecting and Testing Pilot-Operated Pressure Relief Valves
ADB-05-06	August 11, 2005	ADB-05-06 - Pipeline Safety - Countermeasures to Prevent Human Fatigue in the Control Room
ADB-05-07	September 7, 2005	Pipeline Safety Advisory - Potential for damage to Natural Gas Distribution Pipeline Facilities Caused by the Passage of Hurricane Katrina
ADB-05-08	September 7, 2005	Pipeline Safety Advisory - Potential for damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina
ADB-06-01	January 17, 2006	Pipeline Safety: Notice to Operators of Natural Gas and Hazardous Liquid Pipelines To Integrate Operator Qualification Regulations into Excavation Activities

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm

- DOT Part 192 – Transportation of Natural and Other Gas by Pipeline, Subpart E - Welding of Steel in Pipelines
- API Standard 1104 – Standard for Welding Pipelines and Related Facilities
- API RP 1107 – Recommended Pipeline Maintenance Welding Practices
- API Standard 650 – Welded Steel Tanks for Oil Storage
- ASME Pressure Vessel Code Section IX – Welding and Brazing Qualification

3.2.4. Policy

Welding on pipelines or pipeline facilities before being tested and qualified as specified in this policy is prohibited. Welding shall be performed within the essential variables established by the qualification tests. These essential variables are in API Standard 1104, API RP-1107, and Section IX of the ASME code. Welders must be qualified by a Company Welding Inspector under approved welding procedures.

Welders shall be tested and qualified in one or more of the following categories:

- Single qualification (API Standard 1104, Section 6.2) – Category A
- Multiple qualification (API Standard 1104, Section 6.3) – Category B
- Maintenance Welding (API RP-1107, Section 3.0) – Category C
- Tank Welding (API 650, ASME Section IX) – Category D

Welders, tested and qualified under category B, are automatically qualified in categories A and C.

1) Category A and B

   Welders shall be tested and qualified as specified in the latest edition of API Standard 1104 as incorporated in the latest edition of Part 195 (Hazardous Liquids) or Part 192 (Gas) (whichever is appropriate) of the DOT regulations.

2) Category C

   Category C welders shall be tested by one of the following methods:

   a) Method 1

      Multiple qualifications - API Standard 1104 Section 6.3 (Preferred Method)

   b) Method 2

      Test assembly inclined to a 45° angle - API RP-1107 Section 3.2

   c) Method 3

      To qualify for one welding task only (for example, welding on 2" weldolets), the test assembly shall be welded in accordance with Section 6.2 of API Standard 1104 and tested in accordance with Section 6.5 of API Standard 1104.

3) Category D

   Welders shall be tested and qualified as specified in Section IX of the ASME Boiler and Pressure Vessel Code. Welding procedure and positions for qualification testing shall be jointly approved by Construction and Engineering and shall depend on the welding done.

Attach # 1 Pg 10 of 2

Operations or the Engineering Department shall conduct welder qualification tests for Company welders. Operations or the Engineering Department shall be notified at least three working days prior to a scheduled test to ensure a witness is provided.

Copies of qualification forms for all Company welders and contract welders that work steadily for the Company shall be kept on file by Operations or the Engineering Department. The field logistics office shall supply these records to the Engineering Department office.

4) Qualification Forms

The qualification forms required for each category are given below:

Category	Form Number
A	PL–0734
B	PL–0734
C	PL–0736 or PL–0734
D	ASME Form E00008

3.2.5. Welder Requalification

1) Requalification Time Period (Pipeline Welders)

a) Company welders and term contractor welders - Company welders and term contractor welders that work steadily for the Company shall be requalified at periodic intervals not to exceed 12 months for liquid pipeline work and 6 months for gas pipeline work.

b) Contract welders on major pipeline construction projects - Contract welders on major pipeline construction projects shall receive a qualification test by destructive testing before start of the project.

c) Special requalification tests at discretion of company - The Company Welding Inspector or Engineering Department has the right to require requalification of any welder as is deemed necessary.

i) Requalification Method (Pipeline Welders)

To requalify in Categories A, B, C, or Method 1, a welder shall be tested and qualified on a butt weld by either radiographic or destructive testing. The type of testing will be determined by the Company Welding Inspector supervising the test. To requalify in Category C, Method 2 or 3, a welder shall be tested and qualified on the same test assembly used for the initial qualification test.

ii) Requalification for Tank Welders

Before a tank welder can weld using a given process, they must have used that process within the proceeding 3 months or complete requalification testing as determined by the Engineering Department.

3.2.6. Requirements for Welder Max, Welder Min, and Welder Helpers

1) Requirements for Welder Max classification shall include the following:

a) Pass API Multiple Qualification Test - Downhill.

b) Weld uphill, repair leaks, and perform required welding to loaded lines.

c) Layout and fabricate manifolds, etc.

195.222 WELDERS: QUALIFICATION OF WELDERS

(a) Each welder must be qualified in accordance with Section 6 of API Standard 1104 (ibr, see § 195.3) or Section IX of the ASME Boiler and Pressure Vessel Code, (ibr, see § 195.3) except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not re-qualify under that earlier edition.

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has-

(1) Engaged in welding with that process; and

(2) Had one weld tested and found acceptable under Section 9 of API 1104 (ibr, see § 195.3).

NOTE: **Refer to EMPCo's Pipeline Welding Manual for appropriate procedures to be followed.**

195.224 WELDING: WEATHER

Welding must be protected from weather conditions that would impair the quality of the completed weld.

195.226 WELDING: ARC BURNS

(a) Each arc burn must be repaired.

(b) An arc burn may be repaired by completely removing the notch by grinding, if the grinding does not reduce the remaining wall thickness to less than the minimum thickness required by the tolerances in the specification to which the pipe is manufactured. If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed.

(c) A ground may not be welded to the pipe or fitting that is being welded.

195.228 WELDS AND WELDING INSPECTION: STANDARDS OF ACCEPTABILITY

(a) Each weld and welding must be inspected to ensure compliance with the requirements of this subpart. Visual inspection must be supplemented by nondestructive testing.

Attachment 1 Pg 2 of 2

195.234 WELDS: NONDESTRUCTIVE TESTING

(a) A weld may be nondestructively tested by any process that will clearly indicate any defects that may affect the integrity of the weld.

(b) Any nondestructive testing of welds must be performed-

(1) In accordance with a written set of procedures for nondestructive testing; and

(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

(c) Procedures for the proper interpretation of each weld inspection must be established to ensure the acceptability of the weld under §195.228.

(d) During construction, at least 10 percent of the girth welds made by each welder during each welding day must be nondestructively tested over the entire circumference of the weld.

(e) All girth welds installed each day in the following locations must be nondestructively tested over their entire circumference, except that when nondestructive testing is impracticable for a girth weld, it need not be tested if the number of girth welds for which testing is impracticable does not exceed 10 percent of the girth welds installed that day:

(1) 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, and any offshore area;

(2) Within railroad or public road rights-of-way;

(3) At overhead road crossings and within tunnels;

(4) Within the limits of any incorporated subdivision of a State government; and

(5) 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.

(f) When installing used pipe, 100 percent of the old girth welds must be nondestructively tested.

Attach #2 p. 1 of 1

(4) Aerial Markers

Aerial markers shall be installed at appropriate intervals, and at pipeline alignment angles if needed for effective patrol.

(5) Emergency Notification

(A) Install station emergency information signs at each meter station, regulator station, valve site, and other critical locations where considered appropriate, Company's Name and Emergency Telephone Number shall be correctly identified.

(B) Install "No Smoking" signs near each fence gate, meter station building, storage tank, or other hazardous location in a position most prominent to the general public's view.

(6) No Smoking Signs

Install "No Smoking" signs in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

(7) Reporting

During scheduled line patrols, and any other ROW related work, all signs and markers will be inspected and any needed repairs will be reported.

(8) Breakout Tanks

Install and maintain signage around breakout tank areas. Signage must contain the name of the operator and an emergency telephone number.

Attach #41 Pg 1 of 1

- At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire

C. Maintenance of Electrical Test Leads - 195.567(c)

Electrical test leads, required for cathodic protection surveys, must be maintained to ensure that accurate electrical measurements can be obtained.

For additional information on Company's Cathodic Protection Program Procedures, refer to documents **CATHODIC PROTECTION PROGRAM,**

in **ExxonMobil Pipeline's** Intranet Site under **Reference Library / Manuals / FACILITIES INSPECTION AND MAINTENANCE MANAGEMENT SYSTEM (FIMM System) Manual.**

All records associated with cathodic protection surveys, periodic rectifier readings, permanent test station data, and corrective actions are maintained in the computer database program, Cathodic Protection Data Manager (CPDM). Scheduling of the surveys is done through ExxonMobil Maintenance Application (EMA), or other local system where EMA is no available.

§195.569 *Do I have to examine exposed portions of buried pipelines?*

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under §195.585, you must investigate 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.

PROCEDURES:

A. **Exposed Pipe**

Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe. When there is evidence of significant corrosion, the person responsible for corrosion matters must be notified. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

Attach # a or 1 of 5

Attach #6

ExxonMobil Pipeline

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Manuals

Select a Type of Manual...

TITLE	BUSINESS AREA	CONTACT	REVIEW FREQUENCY	DATE REVIEWED
Adminitrative				
Basic Records Retention Schedule	CIC/Global IMS	Mary J. Pursley	As Required	1/1/2006
Construction Industry Institute - Project Definition Rating Index for Industrial Projects	Business Development	Bill Patterson	2 years	4/1/04
Corporate Alcohol & Drug Use Policy	HR	Mary J. Pursley	As Needed	2/16/2005
Corporate Basic Standards	Controllers	Mary J. Pursley	As Required	7/1/1999
Corporate Environmental Policy	HR/OID	Mary J. Pursley	As Needed	2/16/2005
Corporate Health Policy	HR/OID	Mary J. Pursley	As Needed	2/16/2005
Corporate Product Quality Policy	HR/OID	Mary J. Pursley	As Needed	2/16/2005
Corporate Safety Policy	HR/OID	Mary J. Pursley	As Needed	2/16/2005
Corporate Standards of Business Conduct	HR	Mary J. Pursley	As Required	1/6/2006
Delegation of Authority Guide - DOAG	FA&C	Charles Yeates	As Required	2/2/2006
DOAG Process	FA&C	Charles Yeates	As Required	02/01/2000
Financial Analysis and Controls Manual	FA&C	Kim Baumbach	As Needed	09/01/2004
Materials and Services Procurement Manual	Materials and Services Group	Controls Advisor	As required	11/13/03

Attach #4

Project System Manual	Business Development	Bill Patterson	As required	4/3/04
Project System User Guide	Business Development	Bill Patterson	As required	4/3/04
Records Management Guidelines	CIC/Global IMS	Mary J. Pursley	As Required	8/26/2005
Vehicle Policy	Operations	Ted Marsh	As Required	3/14/2005
Warehouse Process	Engineering	Dorsey Allen	As required	7/3/04
Applications				
Centralized Proving and Ticketing (CPTSe)	FA&C	David Sokol	As Required	1/1/2003
Revenue Accounting System (RAS)	FA&C	David Sokol	As Required	1/1/2003
Construction				
Engineering Specialist White Papers	Engineering	Frank Marchhart	Annual	10/5/04
Hydrostatic Test Manual	Engineering	Steve Koetting	1/CY, NTE 15M (Under Review 10/12/05)	6/15/04
Maximum Operating Pressure System Users Guide	Engineering	Junior Lloyd	5 years	2/3/04
Pipeline Repair and Modifications Manual	Engineering	Don Drake	Once per calendar year, not to exceed 15 mo	9/30/2005
Pipeline Welding Manual	Engineering	Don Drake	Once per calendar year, not to exceed 15 mo	9/30/2005
Project Implementation Guide	Engineering Projects	Malcolm South	As required	7/25/2005
Contingency Plans				
EMPCo EMB 2006 BCP	SHE	John W. Dunn	Annual	5/11/2006
EMPCo Emergency Response Quick Reference Guide	SHE	John W. Dunn	As Needed	6/6/2006
EMPCo ESG Manual	SHE	John W. Dunn	As Needed	5/31/2006
OCC Contingency Plan Manual	OCC	Ted Marsh	Annual	7/3/04
Spill/Release Notification Guide	SHE	Thad Massengale	Once per calendar year - Not to exceed 15 mo	12/16/2005

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Design				
E&I Design Practice	Engineering	David Shotwell	As Required	1/30/2006
HAZOP Application Guide	Engineering	Todd Bunnell	As needed	3/10/2006
Mechanical Design Guideline	Projects	Frank Marchhart	5 years	11/10/94
Offshore Design Guide	Projects	Bill Lumpkin	5 years	11/3/2005
Pipe Data Book	Engineering	Norm Yee	5 years	7/2/04
Pipeline Hydraulics Manual	Engineering	Norm Yee	3 years	7/3/04
Risk Assessment Procedures Manual	Engineering	Keith Blair	Annual	3/10/2006
Standard for Automated Custody Transfer Units (GP 81-88-02) - Link to EMEPS Site	Engineering	Pat Abshire	5 years	12/27/04
Standard for P&Ids	Projects	Frank Marchhart	5 years	3/2/04
Temperature and Pressure Calibration Procedures	Engineering	Pat Abshire	As Required	11/30/2005
OIMS				
Critical Safety Equipment Manual	Operations	Ted Marsh	Annually	6/13/2006
Downstream OIMS Guidelines	SHE	M.L. Wilson	2 years	3/1/2004
Facility Control Drawing Guide	CIC	Junior Lloyd	As Needed	2/1/2005
FIMMS Manual	Operations	Johnita Jones	1/CY, NTE 15M Under Review	3/28/2006
Local OIMS Practices Guide	SHE	M.L. Wilson	Annual	8/13/02
OIMS Assessment Guide	SHE	M.L. Wilson	Annual (Under Review 10/12/05)	2/2/04
OIMS Awareness Training	SHE	M.L. Wilson	Annual	4/1/02
OIMS Booklet	CIC	Mary J. Pursley	3 Years	9/2/2005
OIMS Reference Manual	SHE	M.L. Wilson	Annual	4/11/2006
OIMS System 4A Documentation List	CIC	Stefanie R. Johnson	As Needed	6/14/2006
Operations				
Aviation Operations Standards Manual (AOSM, Red Book)	EMPCo	Keith Camp	Annually	1/31/2005
Measurement Manual	OCC	Kenneth R. Wilson	3 Years	8/1/2005
Policies and Guidelines				

GIS Guidance for Controlling Classified Electronic Information	CIC	Mary Jo Pursley (IPA)	As required	6/1/2006
MPI - Safeguarding Information Standards (SMC)	Controllers	Mary Jo Pursley (IPA)	Annual	3/1/2006
MPI Downstream Minimum Common Classification Guide	CIC/Global IMS	Mary Jo Pursley (IPA)	Annual	12/1/2005
MPI Guidelines	CIC/Global IMS	Mary Jo Pursley (IPA)	Annual	12/1/2005
MPI Reference Card	CIC/Global IMS	Mary Jo Pursley (IPA)	Annual	7/1/2005
Regulatory Compliance				
DOT Gas Manual	SHE	M. H. Adams	Once per calendar year, not to exceed 15 mo	2/1/2006
DOT Liquid Manual	SHE	M. H. Adams	Once per calendar year, not to exceed 15 mo	1/30/2006
EMPCo Air Emissions Inventory Procedures Document	SHE	Frank Rogers	Annually	2/13/2006
EMPCo Anti-Drug and Alcohol Misuse Plan	SHE	Catherine O Casey	Annual (Under Review)	6/22/2005
EMPCo Injury Illness Prevention Program (California)	Operations	Ralph L. Mixon	Annually	7/29/2005
Environmental Permit Handbook-Webster -Air-NSR/PSD Permits	SHE	Wesley Crawford	As Required	10/1/01
EPI-KPI EMPCo Supplemental Guide	SHE	Ray Ramirez	Annually	6/9/2006
Field ERST Tech Regulatory Compliance Guidebook	SHE	Thad Massengale	Annual (Under Review 10/12/05)	8/2/2002
Green Book Air, Water, Hazardous Waste & Other - Permits	SHE	Field Enviornmental Advisors	Annually	11/7/2005
Incident Notification & Reporting Guide	SHE	Ron Walton	Annual	4/20/2006
Integrity Management Program	Operations	Johnita Jones	Once per calendar year, not to exceed 15 mo	06/27/2005
Integrity Management Program - Gas Rule Requirements (Appendix J)	Operations	Johnita Jones	Annual	12/15/2004

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New York PBS Manual	SHE	Tim S. Martin	Annual	4/12/2006
One Call Procedures Manual	Operations	Teresa Anderson	1/CY, NTE 15M - UNDER REVIEW	1/2/2006
Public Awareness Plan RP 1162	Public Affairs	Brian Dunphy	Annual	6/19/2006
Qualification of Pipeline Personnel Covered Task List	SHE	Paul Merritt	1/CY, NTE 15M	10/31/2005
Qualification of Pipeline Personnel Guidance Document	SHE	Paul Merritt	1/CY, NTE 15M	10/31/2005
Qualification of Pipeline Personnel Written Program	SHE	Paul Merritt	1/CY, NTE 15M	10/31/2005
Qualification of Pipeline Personnel, Abnormal Operating Conditions Test (March 2006)	SHE	Paul Merritt	1/CY, NTE 15M	3/9/2006
Qualification of Pipeline Personnel, Abnormal Operating Conditions Test with Answers (March 2006)	SHE	Paul Merritt	1/CY, NTE 15M	3/9/2006
Qualification of Pipeline Personnel, Abnormal Operating Conditions Training (March 2006)	SHE	Paul Merritt	1/CY, NTE 15M	3/9/2006
Source Inspection Handbook	SHE	Wesley Crawford		10/1/00
The Emergency Response Action Plan (ERAP) & Oil Spill Response Plan (OSRP)	SHE	Tom Jamieson	Annually	12/6/2005
Waste Management Plan	SHE	Ray Ramirez	Annual	6/7/2006
Safety				
Conducting an Investigation	SHE	Ron Walton	Annual	6/3/04
Contractor Orientation Training	SHE	Tommy G. Jackson	Annual	3/24/2006
Contractor Safety and Administration Manual	SHE	Tommy G. Jackson	As Required	1/9/2006
EMPCo Approved Chemical List (June 13, 2006)	SHE	Paul Merritt	As Needed	6/13/2006
EMPCo Safety Manual	SHE	Eric Niederstadt	Annually	2/16/2006
Guidelines for Safe Entry into In-Service Petroleum Storage Tank & Access onto the IFR	SHE	Paul Merritt	As Required	10/1/2004
Hearing Conservation Program	SHE	Paul Merritt	As Required	2/1/2005

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Lead Program	SHE	Paul Merritt	As Required	2/1/2005
Safety Manual	SHE	Eric Niederstadt	3 Years	2/5/2004
Safety Manual Revisions 3-03	SHE	Eric Niederstadt	As Required	3/3/04
Training				
2004 Training & Education Guide	SHE	Jan Bowman	As Required or Triennial	10/25/2004

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Operator: ExxonMobil Pipeline Company (EMPCo)
Op ID (s): 4906

US Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Field Verification Inspection

Integrity Management Program
49 CFR Part 195.452

General Notes:

1. This Field Verification Inspection is performed on specific field activities being performed by an Operator in support of their Integrity Management Program (IMP).
2. Not all parts of this form may be applicable to a specific Field Verification Inspection, and only those applicable portions of this form need to be completed.
3. This form may be combined with the "IOCS Activity Report" to fulfill the Post Inspection Memo requirement.
4. This is a two part inspection:
    i. A review of applicable Operations and Maintenance (O&M) and IMP processes and procedures applicable to the field activity being inspected to ensure the operator is implementing their IMP in a consistent manner.
    ii. A Field Verification Inspection to determine that activities on the pipeline and facilities are being performed in accordance with written procedures or guidance.

Integrity Management

Inspection Form for Field Verification

Name of Operator: ExxonMobil Pipeline Company (EMPCo)

Headquarters Address:
3225 Gallows
Fairfax, VA 22037

Company Official: John DuPre, V.P. Operations - Northern

Phone Number:

703-846-6692

Fax Number:

703-846-6904

Operator ID:

4906

Activity ID:

1255

Persons Interviewed	Title	Phone No.	E-Mail
Thad Massengale	Primary Contact	713-656-2258	
Robert D. Foote	Montana Area Superintendent	406-657-5400	
James A. Althoff	Senior Operations Tech. A	406-662-3569	
Steve Everett	Technican	406-662-3569	
Dave Ort	CP Tech	661-763-7621	

OPS/State Representative(s): Jerry Davis **Dates of Inspection: 6/20-22/2006**

Inspector Signature: _____

System Descriptions:

The 12.75" pipeline originates at the Silvertip pump station (Elk Basin field) in Carbon County, MT and terminates at the ExxonMobil refinery in Billings, MT. This pipeline is made up of approximately 22 miles of 12 3/4 inch diameter, .250 wt. X-42 and X-35 ERW pipe installed in 1949 and 1954, approximately 44.5 miles of 12 3/4 inch diameter, .312 wt. X-35 ERW pipe installed in 1949 and 1957, 2.5 miles of 12 3/4 inch diameter .375 inch pipe installed in the 50's and 60's. The balance of the 69 plus mile long pipeline is made up of both ERW and SMS 8 5/8 inch, .322 wt pipe and 12 3/4 inch .375 and .5 inch wt pipe. This system includes a pump station with 5 breakout tanks at the Silver Tip station, and a booster station at Bridger, MT. The line delivers crude oil to both the ConocoPhillips refinery and the ExxonMobil refinery in Billings, MT. A Cenex pipeline booster station, located in Laurel, MT, delivers crude oil from Cenex Pipeline's Front Range Pipeline. In 2005 there was a tie-in made to the Terasen Pipeline's Express pipeline at Terasen's Edgar station, MT. This tie-in consists of two ½ mile long 12 3/4-inch, X-52, .312 wt pipelines from the Silvertip pipeline to the Edgar station. At the Edgar Station ExxonMobil installed 2 pumps to receive crude from Terasen's breakout tanks. This pipeline now receives crude from the Express pipeline, the Silvertip station or from Cenex's Front Range pipeline. Crude from the Express pipeline is kept separate from all other flows, it is considered a syncrude. Operating pressure ranges from 400-900 psi, depending on demand and location.

Site Location of field activities:

I inspected records and some procedures at the Bridger office. I inspected the ROW where CP monitoring indicated a low CP reading, the upstream Clarks Fork MOV, the Bridger station, the terminal facility at the ExxonMobil refinery in Billings, the upstream Yellowstone River MOV in Billings, the King Avenue MDT construction project that crosses the Silvertip pipeline, the Horse Palace replacement project site, the site of a proposed Walmart in Laurel, MT where the Silvertip pipeline crosses under the proposed parking lot, the Cenex Front range tie-in at the Cenex refinery in Laurel, MT, the upstream Yellowstone MOV in Laurel, the Edgar station and tie-in, and the Elbow creek upstream manual block valve.

Key Documents Reviewed:

Document Title	Document No.	Rev. No	Date
Various repair documentation from 2004 ILI tool run			**2004**
Magpie/TD Williamson 2004 ILI tool run report			
Welding Procedures			
Facilities Inspection and Maintenance Management System FIMMS		**1.25**	**1/2/06**
DOT Liquid Manual			**1/30/06**
Pipeline Welding Manual			**8/8/03**

Part 1 - Performance of Integrity Assessments

In-Line Inspection (Protocol 3.04 & 3.05)	No Issue	Issue	N/A	Notes: Tool speed was kept around 5 mph. The limit of the tool is between 1 and 9 mph. This was a Magpie, TD Williamson MFL tool and deformation tool.
Verify that Operator's O&M and IMP procedural requirements (e.g. launching/receiving tools) for performance of ILI were followed.	✓			
Verify Operator's ILI procedural requirements were followed (e.g. operation of trap for launching and receiving of pig, operational control of flow), as appropriate.				
Verify ILI tool systems and calibration checks before run were performed to ensure tool was operating correctly prior to assessment being performed, as appropriate.				
Verify ILI complied with Operator's procedural requirements for performance of a successful assessment (e.g. speed of travel within limits), as appropriate.				
Document ILI Tool Vendor and Tool type (e.g. MFL, Deformation). Document other pertinent information about Vendor and Tool, as appropriate				
Other:				

Hydrostatic Pressure Testing (Protocol 3.06)	No Issue	Issue	N/A	Notes: They used a smart tool as the assessment method.
Verify that hydrostatic pressure tests complied with Part 195 Subpart E requirements.			✓	
Review documentation of Hydrostatic Pressure Test parameters and results. Verify test was performed without leakage and in compliance with Part 195 Subpart E requirements.				
Review test procedures and records and verify test acceptability and validity.				
Review determination of the cause of hydrostatic test failures, as appropriate.				
Document Hydrostatic Pressure Test Vendor and equipment used, as appropriate.				
Other:				

Other Assessment Technologies (Protocol 3.07)	No Issue	Issue	N/A	Notes: They used a smart tool as the assessment method.
Verify that application of "Other Assessment Technology" complied with Operator's requirements, that appropriate notifications had been submitted to OPS, and that appropriate data was collected.			✓	
Review documentation of notification to OPS of Operator's application of "Other Assessment Technology". Verify compliance with Operator's procedural requirements and performance of assessment within parameters originally submitted to OPS.				
Verify that appropriate tests are being performed and appropriate data is being collected, as appropriate.				
Other.				

Part 2 - Remediation of Anomalies

Remedial Actions – Process (Protocol 4.1)	No Issue	Issue	N/A	Notes: Anomaly remediation had already occurred for this pipeline. I did observe during my daily activities throughout the last 2 years, that there have been several excavations along this pipeline by ExxonMobil forces. I inspected the anomaly prioritized callout list and several of the inspection/repairs associated with those anomalies. Some of the locations of these digs where areas I had observed ExxonMobil digging on during the last two years.
Verify that remedial actions complied with the Operator's procedural requirements.	✓			
Witness anomaly remediation and verify documentation of remediation (e.g. Exposed Pipe Reports, Maintenance Report, any Data Acquisition Forms). Verify compliance with Operator's O&M Manual and Part 195 requirements.				
Verify that Operator's procedures were followed in exposing the anomaly (e.g. any required pressure reductions, line location, excavation, coating removal).				
Verify that procedures were followed in measuring the anomaly, determining the severity of the anomaly, and determining remaining strength of the pipe.				
Other:				

Remediation - Implementation (Protocol 4.02)	No Issue	Issue	N/A	Notes: See above comments. They used Armor Plate wrap for repairs. Number of wraps depended on the depth of the pit. CoreCal was the methodology used for determining remaining strength, it is modified B31G.
Verify that the operator has adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis.	✓			
Verify that repairs were completed in accordance with the operator's prioritized schedule and within the time frames allowed in §195.452(h).				
Review any changes to the schedule. Ensure that the changes to the schedule were justified by the operator and the schedule changes were demonstrated not to jeopardize public safety or environmental protection, as appropriate.				
Review any documentation of cases where OPS was notified that the repair schedule could not be met, remediation exceeded the time frames allowed in §195.452(h), and safety could not be provided through a reduction in operating pressure.				
Review any documentation of cases for an immediate repair condition (§195.452(h)(4)(i) where operating pressure was reduced or the pipeline was shutdown. Verify for an immediate repair condition that temporary operating pressure was determined in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or, if not applicable, the operator should provide an engineering basis justifying the amount of pressure reduction.				
Verify that repairs were performed in accordance with §195.422 and the Operator's O&M Manual, as appropriate.				
Review CP readings at anomaly dig site, if possible. (See Part 4 of this form – "Field Inspection to Verify adequacy of the Cathodic Protection System" , as appropriate.				
Other:				

Part 3 - Preventive and Mitigative Actions

Installed Leak Detection System Information (Protocol 6.05)	No Issue	Issue	N/A	Notes: They have a CPM system on this pipeline. They did a simulated test, ie not actually withdrawing product, and the test came out good. The simulated test of the CPM system was done on the Silvertip pipeline.
Identify installed leak detection systems on pipelines and facilities that can affect an HCA.	✓			
Document leak detection system components installed on system to enhance capabilities, as appropriate.				
Document the frequency of monitoring of installed leak detection systems and verify connection of installed components to leak detection monitoring system, as appropriate,				
Other:				

Installed Emergency Flow Restrictive Device (Protocol 6.06)	No Issue	Issue	N/A	Notes: Each river crossing on the Silvertip pipeline has an upstream remote control valve with a pressure relief bypass to prevent un-commanded closures from over-pressuring the pipeline.
Verify additional preventive and mitigative actions implemented by Operator.	✓			
Document Emergency Flow Restrictive Device (EFRD) component(s) installed on system. Note that EFRD per §195.450 means a check valve or remote control valve as follows: (1) Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction. (2) Remote control valve or RCV means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.				
Document the frequency of monitoring of installed EFRDs and verify connection of installed components to monitoring/operating system, as appropriate.				
Comment on the perceived effectiveness of the EFRD in mitigating the consequences of a release on the HCA that it is designed to protect.				
Other:				

Part 4 - Field Investigations (Additional Activities as appropriate)

Field Inspection for Verification of HCA Locations	No Issue	Issue	N/A	Notes: I did not review their HCA maps but records of repairs show that these repairs were in those locations that NPMS shows as HCAs.
Review HCAs locations as identified by the Operator. Utilize NPMS, as appropriate.	✓			
Verify population derived HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document newly constructed (within last 2-3 years) population and/or commercial areas that could be affected by a pipeline release, as appropriate. Note that population derived HCAs are defined in §195.450				
Verify drinking water and ecological HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document newly established drinking water sources and/or ecological resources areas (within last 2-3 years) that could be affected by a pipeline release. Note that unusually sensitive areas (USAs) are defined in §195.6				
Verify commercially navigable waterway HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document any activity (commercial in nature) that could affect the waterways status as a commercially navigable waterway, as appropriate. Note that commercially navigable waterway HCAs are defined in §195.450				

Field Inspection for Verification of Anomaly Digs	No Issue	Issue	N/A	Notes: They did correlation digs.
Verify repair areas, ILI verification sites, etc.	✓			
Identify anomaly dig sites in the area, if possible, that will not be investigated as part of this field activity (e.g. three other digs to be performed in this area, but not part of this inspection)				

Field Inspection to Verify adequacy of the Cathodic Protection System	No Issue	Issue	N/A	Notes: They used a smart tool as the assessment method.
In case of hydrostatic pressure testing, Cathodic Protection (CP) systems must be evaluated for general adequacy.			✓	
Review records of CP readings from CIS and/or annual survey to ensure minimum code requirements are being met, if available.				
Review results of random field CP readings performed during this activity to ensure minimum code requirements are being met, if possible.				
Perform random rectifier checks during this activity and ensure rectifiers are operating correctly, if possible.				

Field inspection for general system characteristics	No Issue	Issue	N/A	Notes: Please see standard inspection.
Through field inspection determine overall condition of pipeline and associated facilities for a general estimation of the effectiveness of the operator's IMP implementation.			✓	
Visit nearby pump stations, valve settings, aboveground crossings, etc. to ensure minimum code requirements are being met, if possible and as appropriate.				
Evaluate condition of the ROW to ensure minimum code requirements are being met, as appropriate.				
Comment on Operator's apparent commitment to the integrity and safe operation of their system, as appropriate.				
Other				

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: ExxonMobil Pipeline Company	
OP ID No. [1] see below	**Unit ID No.** [1]
H.Q. Address:	**System/Unit Name & Address:** [1]
800 Bell Street, Room 741D Houston, Texas 77002	
Co. Official: Mr. Gary Pruessing, President	**Activity Record ID#:**
Phone No.: 713-656-5056	**Phone No.:**
Fax No.: 713-656-9579	**Fax No.:**
Emergency Phone No.: 800-537-5200	**Emergency Phone No.:**

Persons Interviewed	Titles	Phone No.
Cathey Casey	Pipeline Safety Advisor	713-656-6913
Thad Massengale	Pipeline Safety Advisor	713-656-2258
Guy Peltier	Pipeline Safety Advisor	
Don Drake	Metallurgist	

PHMSA Representative(s) [1] **Jim Arnold, Jon Manning, Bob Smallcomb, Jason Terry**	**Inspection Date(s)** [1] **4/2-6/2007**
Company System Maps (copies for Region Files):	N/A

Unit Description:
OPID's
4906 ExxonMobil Pipeline Company
12628 Mobil Pipeline Company
26120 Collins Pipeline
31167 MOEM Pipeline LLC
ExxonMobil operates 8361 miles of pipeline with 905 employees
Approximatley 255 Breakout tanks

Portion of Unit Inspected [1]

Headquarters Team O&M procedures inspection

*Startup and shut down site specific procedures will need to be reviewd during standard inspection

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/02/02 and 03/02/07.

[1] Information not required if included on page 1.

Warren Miller 5/2/07

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		CONVERSION TO SERVICE	S	U	N/A	N/C
*	.5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.	x			

Comments:
Subpart A General pg 45

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).	x			
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**	x			
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery	x			
	.54(b)	Supplemental report - required within 30 days of information change/addition	x			
	.55	Safety-related conditions (SRC) - criteria	x			
	.56(a)	SRC Report is required to be filed within five (5) working days of the determination and within ten (10) working days after discovery	x			
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)	x			

Comments:
Subpart B Reporting pg 55-64;Subpart F Operations and Maintenance pg 128

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section	x			

Comments:
Subpart C Design pg 78; EMEPS GP-59-01-01 Onshore Pipeline Design;Offshore Design Guide**need to update referenceon pg 78 of manual

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.	x			
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.	x			
		Welding procedures must be qualified by destructive testing.	x			
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.	x			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 pub 06/09/06 eff 07/10/06.	x			
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	x			
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.	x			
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate).** Pipe must be removed for non-repairable notches.	x			
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.	x			
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **§195.228(b)** and per the requirements of **§195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.	x			
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**	x			
		2. By qualified personnel	x			
		3. By a process that will indicate any defects that may affect the integrity of the weld	x			
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.	x			
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.		**		

Comments:
Subpart D Construction pg 84; Pipeline Welding Manual Section 3 Welding and Welder Qulaifications; Section 2 General Welding Requirements for Pipeline Welding; Section 6 Radiographic; Section 5 Inspection and Repair Testing Pipeline Repair and Modification Manual**add Boiler and Pressure vessel code**need procedure to include inspection of weld after repair has been completed(Table 19 explain asterick)

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).	x			
	.302(b)	Except for lines converted under **§195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.	x			
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).	x			
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)	x			

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Comments:
Subpart F Maintenance and Operations**appropriate parts need to be available at locations where O&M activities are conducted

MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?	x			
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?	x			
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph (c)(4) and minimizing the possibility of recurrence of accidents analyzed under paragraph (c)(5)?	x			
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by §195.406, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?	x&			
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406?	x			
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under §195.402(c)(4) or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?	x			
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards	x			
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per §195.59.	x			
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases?	x			
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.	x			
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?	x			
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.	x			

Comments:
Subpart F Maintenance and Operations (&Startup and shut down site specific procedures will need to be reviewd during standard inspection); Subpart B Reporting pg 67; Emergency Response Manual Section 5; EMPCO Public Awareness Plan; Safety Manual Confined Space-Excavation Manual

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?	x			
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?	x			
		iii. Loss of communications?	x			

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
		iv. The operation of any safety device?	x			
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?	x			
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?	x			
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?	x			
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?	x			
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?	x			

Comments:
Subpart F Maintenance and Operations pg 120-122; OCC Operating Instructions(Daily Trouble Sheet)

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?	x			
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?	x			
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?	x			
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?	x			
	.402(e)(5)	Controlling the release of liquid at the failure site?	x			
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?		**		
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?		**		
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?	x			
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?	x			

Comments:
Subpart F Operations and maintenance pg 122-128 ;OCC Operating Instructions; Emergency Response Plan Volume 1**need to include railroad traffic**reference to section 5 of emergency manual

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.	x			
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.	x			
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.	x			

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		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
	.403(a)(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.	x			
*	.403(a)(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. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	x			
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.		**		
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program	x			
	.403(b)(2)	Make appropriate changes to the emergency response training program	x			
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.	x			

Comments:
Subpart F Operations and Maintenance pg136-138; pg 128**remove "about" 402f)

		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.	x			
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks	x			
		ii. Pump stations	x			
		iii. Scraper and sphere facilities		**		
		iv. Pipeline valves	x			
		v. Facilities to which **§195.402(c)(9)** applies		**		
		vi. Rights-of-way		**		
		vii. Safety devices to which **§195.428** applies	x			
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.		**		
	.404(a)(3)	The maximum operating pressure of each pipeline.	x			
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.	x			
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.	x			
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under **§195.402** apply.	x			
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.	x			
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.	x			
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.		**		

Comments:

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Comments:
Subpart F Operations and maintenance pg 111, pg 139-141**Procedures need to specify that scraper and sphere facilities, Facilities the are not equipped to fail safe in immediate response areas and rights-of-way will be identified on current company maps.**Procedures need to specify the company will maintain current maps and records identifying rivers, buried utilities and foreign pipelines**include monthly Tank inspection records as required by API 653

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by **§195.106.** Amt 195-86 pub 06/09/06 eff 07/10/06.		**		
	.406(a)(2)	The design pressure of any other component on the pipeline.		**		
	.406(a)(3)	**80%** of the test pressure **(Subpart E).**		**		
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.		**		
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E.**		**		
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:		**		
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP.**		**		

Comments:
Subpart F Operations and Maintenance pg 143**need procedures for MOP not exceeding (a)(1) through (a)(5) and/or procedure reference NOTE:**need reference for design GP/Local Operating instructions pg 144 for operation contraints**add language to O&M stating that overpressure protection equipment must be installed to prevent the pressure from exceeding 110% of MOP

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.	x			
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9).**		**		
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.	x			
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.	x			
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.		**		

Comments:
Subpart F Operations and Maintenance pg 146; Emergency Response Manual**need to define failsafe**need procedure or reference for alternate form of communication i.e. GETS to insure establishment of communications during emergencies or natural disasters.

		LINE MARKER PROCEDURES	S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known		**		
	.410(a)(2)	Must have the correct characteristics and information	x			
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public	x			

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Comments:
Subpart F pg 148**procedure needs to be more descriptive on placement of line markers

		INSPECTION RIGHTS-of-WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES	S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**	x			
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**.	x			

Comments:
Subpart F pg 150-151; FIMMS Manual Aerial Patrol; Navigable Crossing Inspection (need to add "crossing" pg 150)

		UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES	S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.	x			
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.	x			
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.	x			
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.	x			
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.	x			
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections	x			

Comments:
Subpart F pg 152 Underwater Inspection Plan

		VALVE MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.	x			
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.	x			
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.		**		

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Comments:
.Subpart F pg 154**procedure needs reference Appendix E (Security Guidlines) for how valves will be protected from vandalism

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.	x			
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.	x			

Comments:
Subpart F pg 156; Repair and Modification manual section 2 &4

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.	x			
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.	x			
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.	x			
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**	x			
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.	x			
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.	x			
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.	x			

Comments:
Subpart F pg 158-161; Repair and Modification Manual Section 7

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.	x			
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.	x			

Comments:

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Comments:
Subpart F pg 161

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.		**		
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.	x			
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.	x			
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.	x			
*	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt 195-86 pub 06/09/06 eff 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.	x			
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.	x			

Comments:
Subpart F pg 162**procedure needs to be more descriptive on what steps are taken to validate inspections of overpressure protection provided by a third party operator.; ?paragraph at top of 163?

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.		**		
		The equipment must be:				
		a. In proper operating condition at all times.	x			
		b. Plainly marked so that its identity as firefighting equipment is clear.	x			
		c. Located so that it is easily accessible during a fire.	x			

Comments:
Subpart F pg 165**Procedures need to specify how the operator determines the adequacey of firefighting equipment for each pump station and breakout tank area

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c);**				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **§195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				x
*	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt 195-86 pub 06/09/06 eff 07/10/06.				x
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999,** or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				x
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Breakout tank specific procedures were inspected in more detail using Form 10.

		SIGN PROCEDURES	S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.	x			
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.	x			

Comments:
Subpart F pg 168

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.	x			

Comments:
Subpart F pg 169, Appendix E Security Guidelines

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.		**		

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Subpart F pg 169; EMPCO Safety Manual; pg 149**need to reference .410 procedure in liquid manual for installation of "No Smoking" signs

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				x

Comments:
Public Awareness plan submitted to HQ

		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?	x			
	.442(b)	Does the operator participate in a qualified One-Call program?	x			
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.	x			
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.	x			
		ii. How to learn the location of underground pipelines before excavation activities are begun.	x			
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.	x			
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.		**		
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.	x			
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.	x			
		ii. In the case of blasting, any inspection must include leakage surveys.		**		

Comments:
Subpart F pg 175; EMPCO One-Call Manual(reference Public Awarenes Plan)**precedure needs to describe how an excavator is notified of the type of temporary marking provided and how to identify the marking.**procedures nned to specify that a leakage survey will be performed after any blasting close to the pipeline.

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt 195-86 pub 06/09/06 eff 07/10/06.	x			

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

Subpart F pg 175(as defined in guidance material EM's sysem does not have to be inspected per .134 and .444

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

SUBPART H - CORROSION CONTROL PROCEDURES			S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?	x			
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424.**	x			
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;			x	
		2) Is a segment that is relocated, replaced, or substantially altered?			x	
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.		**		
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.		**		
		b. All coating damage discovered must be repaired.	x			
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**	x			
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or	x			
		2) Is a segment that is relocated, replaced, or substantially altered?	x			
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.	x			
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.	x			
		e. Unprotected pipe must have cathodic protection if required by **195.573(b).**	x			

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.567	Test leads installation and maintenance.	x			
	.569	Examination of Exposed Portions of Buried Pipelines.		**		
*	.571	Cathodic protection 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 Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.	x			
	.573	a. (1) Pipe to soil monitoring **(annually / 15months).**	x			
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months).**			x	
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify 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 RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.	x			
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment			x	
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**			x	
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**	x			
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)	x			
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**	x			
	.575	Are there adequate provisions for electrical isolations?	x			
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.	x			
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.	x			
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.	x			
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**	x			
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.		**		
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).	x			
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**		**		
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**		**		
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?	x			
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?	x			

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**	x			
	.589	Corrosion Control Records Retention (Some are required for 5 yrs; Some are for the service life).	x			

Comments:
Subpart H Corrosion Control pg 201-;FIMMS Corrosion Control; GP198701; GP590112**Procedures need to reference coating testing documents and/or specify what coating material specifications are required.**Procedures for electronic testing of coating should be more specific for sensitivity settings for anomaly detection.**procedure needs to specify that if external corrosion is found requiring corrective action, the pipe must be investigated circumfrentially and logitudinaly beyond the exposed portion to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion**procedure needs to specify that if internal corrosion is found requiring corrective action, the pipe must be investigated circumfrentially and logitudinaly beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe**Procedures need to address repair criteria based on evaluation of atmospheric corrosion inspection N/A: ExxonMobil does not have any converted pipelines, seperatley protected short sections or bare pipelines

Subpart F - Operations & Maintenance (Breakout Tanks)		S	U	N/A	N/C
§195.402(a)	**General O&M Requirement:** Each operator must prepare and follow for each pipeline system (including breakout tanks) a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies				
	Does the operator have written procedures for Breakout tanks? (Procedures must address operations, maintenance, repair, emergency, and abnormal operations.)	X			
195.404(a)(1)(i)	**Maps:** Are maps and records maintained showing the location and identification of the following;				
	1. Breakout tanks (capacity, other information)	X			
	2. Pipeline valves (tank isolation valves, manifold valves, emergency valves..,)	X			
	3. Cathodically protected tanks and associated facilities	X			
	4. Overpressure and overfill safety devices (as required under 195.428)	X			
§195.402(a)	**Protection against Ignition and Safe Access/Egress Involving Floating Roofs**				
§195.402(c)(3)	405(a). **Protection against Ignition (After October 2, 2000)** Protection against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with **API Recommended Practice 2003 (Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents).** *Not required if operator notes in procedures why compliance with API 2003 is not necessary for tank safety).* ***(Refer to Subsection 4.5, Subsection 4.6, Subsection 5.4 , Subsection 5.5, and Subsection 6.3 of API RP 2003)***	X			
	405(b). **Safe Access/Egress Involving Floating Roofs (After October 2, 2000)** The operator must review and consider the potentially hazardous conditions, safety practices and procedures with respect to access/egress onto floating roofs of in-service aboveground breakout tanks to perform inspection, service, maintenance or repair activities in **API Publication 2026 (Safe Access/Egress Involving Floating Roofs Of Storage Tanks In Petroleum Service)** for inclusion in the procedure manual (Sec. 195.402(c)).				

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	Has the operator reviewed and considered the potentially hazardous conditions, safety practices and procedures outlined in **API 2026 (Safe Access/Egress Involving Floating Roofs Of Storage Tanks In Petroleum Service)** for inclusion in the operator's procedure manual? *Review for documentation that this has been done.*	X				

Comments:
Subpart F pg 165-168; OCC Operating Instructuions Patoka Tank Farm; Safety Manual

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§195.402(a)		External Corrosion Control	S	U	N/A	N/C
§195.402(c)(3)	.563(d)	Breakout tank areas, bare pipelines, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.	X			
	.565	**Breakout Tank CP installation** Does operator install (after 10/2/00) required cathodic protection systems to protect above ground breakout tanks over 500 bbl capacity, in accordance with API RP 651? *(Not required if operator notes in the corrosion control procedures why compliance with API 651 is not necessary for tank safety).*	X			
	.571	**Cathodic Protection Acceptance Criteria** Cathodic protection levels must comply with the applicable criteria outlined in NACE Standard RP0169-96 (paragraphs 6.2 and 6.3)	X			
	.573(d)	**Breakout Tank CP inspections**				
		Cathodic protection systems used to protect breakout tanks must be inspected in accordance with API 651.	X			
		(Not required if operator notes in the corrosion control procedures why compliance with API 651 is not necessary for tank safety).				
	11.3.2	**Cathodic Protection Surveys** - Annual CP surveys are required. Surveys may include one or more of the following:				
		1. Structure to soil potential.	X			
		2. Anode current.			X	
		3. Native structure to soil potentials			X	
		4. Structure-to-structure potential			X	
		5. Piping-to-tank isolation if protected separately.			X	
		6. Structure-to-soil potential on adjacent structures.			X	
		7. Continuity of structures if protected as a single structure.			X	
		8. Rectifier DC volts, DC amps, efficiency, and tap settings.			X	
		Rectifier Inspections:				
		- every 2 months. - (Inspections should include a check for electrical shorts, ground connections, meter accuracy, and circuit resistance).	X			
		- Annual inspection (Inspections should include a check for electrical shorts, ground connections, meter accuracy, efficiency, and circuit resistance).	X			
	11.3.3.3	**Insulator, bonds, isolating devices** - Must be done periodically. May be done by on-site inspection or evaluating corrosion test data.	X			
	11.3.3.4	**Tank Bottoms** - Tank bottom should be examined for evidence of corrosion whenever access to the bottom is possible. (During repairs, modifications, during API653 inspections) Examinations may be done by coupon cutouts or nondestructive methods.	X			

Comments:

Subpart F pg GP097734

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§195.402(a)		External Corrosion Control (cont.)	S	U	N/A	N/C
	.577(a)	**Interference Currents** For breakout tanks exposed to stray currents, is there a program to minimize the detrimental effects?	X			
	.579(d)	**Breakout tank - internal corrosion mitigation** After October 2, 2000, tank bottom linings installed in tanks built to **API 12F (Specification for Shop Welded Tanks for Storage of Production Liquids), API 620 (Design, Construction, Large, Welded, Low-Pressure Storage Tanks), API 650 (Welded Steel Tanks for Oil Storage), or its predecessor 12C** must be installed in accordance with API RP 652. *Not required if operator notes in the corrosion control procedures why compliance with API 652 is not necessary for tank safety.*	X			
§195.402(a)		**Tank Repairs, Alterations, and Reconstruction Procedures**				
§195.402(c)(3) §195.422	.205(a)	Aboveground breakout tanks repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads. *The repair/alteration history includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes (recorded with service conditions such as stored product temperature and pressure). These records should include the results of any experiences with coatings and linings.*	X			
	.205(b)	After Oct. 2, 2000 compliance with paragraph (a) above requires:				
		(1) Tanks designed for approximately atmospheric pressure, constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated built to **API Standard 650 (Welded Steel Tanks for Oil Storage)** must be repaired, altered, or reconstructed according to API Standard 653. *The basis for repairs and alterations shall be an API Standard 650 equivalence*	X			
		(2) Tanks built to API Specification 12F (Specification for Shop Welded Tanks for Storage of Production Liquids) or API Standard 620 (Design, Construction, Large, Welded, Low-Pressure Storage Tanks), the repair, alteration, and reconstruction must be in accordance with the design, welding, examination, and material requirements of those respective standards. Tanks built to API 620 may be modified by the design, welding examination and testing provisions of API 653 in proper conformance with the stresses, joint efficiencies, material and other provisions in API standard 620.			X	
		(3) For high pressure tanks built to API Standards 2510 (Design and Construction of LPG Installations), repaired, altered, or reconstructed will be in accordance with API 510 (Pressure Vessel Inspection Code).			X	
	.422	Are repairs made in a safe manner and are made so as to prevent damage to persons or property?	X			

Comments:
Subpart H pg 215

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	Impoundment, Protection Against Entry, Relief, and Venting Procedures-Aboveground Breakout Tanks	S	U	N/A	N/C
	.264(a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank. Containment and impoundment are effective means of controlling environmental releases and fires.	X			
	.264(b) After Oct. 2, 2000, compliance with paragraph (a) above requires:				
	(1) For tanks built to **API Specification 12F (Specification for Shop Welded Tanks for Storage of Production Liquids)**, **API Standard 620 (Design, Construction, Large, Welded, Low-Pressure Storage Tanks)**, and others (such as **API Standard 650** or its predecessor Standard **12C**), the installation of impoundment must be in accordance with the following sections of **NFPA 30 (Flammable and Combustible Liquids Code):**				
	(i) Impoundment around a breakout tank must be installed in accordance with Section 3.2.3.2; and		**		
	(ii) Impoundment by drainage to a remote impounding area must be installed in accordance with Section 4.3.2.3.1.			X	
	(2) For tanks built to **API Standard 2510**, the installation of impoundment must be in accordance with Section 5 or 11 of **API Standard 2510. (Design and Construction of LPG Installations):** *Refer to Section 5 API Standard 2510 - Siting Requirements and Spill Containment* *5.1 Siting* *5.2 Drainage* *5.3 Spill Containment* *5.4 Remote Impoundment* *5.5 Diking* *Section 11 - Refrigerated Storage* *11.3 Siting Requirements* *11.3.1 Minimum Distance Requirements for Refrigerated LPG Tanks* *11.3.2 Siting of Refrigerated LPG Tanks* *11.3.3 Spill Containment* *11.3.4 Remote Impoundment* *11.3.5 Diking*			X	

Comments:
GP090101**all tank containment areas need to be installed in accordance with NFPA 30

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	Impoundment, Protection Against Entry, Relief, and Venting Procedures-Aboveground Breakout Tanks (cont.)	S	U	N/A	N/C
	.264(d) Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure/vacuum-relieving devices must be provided for each low-pressure and high-pressure breakout tank. *Two basic types of pressure or vacuum vents, direct-acting vent valves and pilot-operated vent valves, are available to provide overpressure or vacuum protection for low-pressure storage tanks. Direct-acting vent valves may be weight loaded or spring loaded. Another type of venting device, an open vent, is available to provide overpressure or vacuum protection for storage tanks designed to operate at atmospheric pressure. An open vent is always open. It allows a tank designed to operate at atmospheric pressure to inbreathe and outbreathe at any pressure differential.*	X			
	.264(e) For normal/emergency relief venting and pressure/vacuum-relieving devices installed on aboveground breakout tanks after October 2, 2000, compliance with paragraph (d) of this section requires the following for the tanks specified:				
	(1) Normal/emergency relief venting installed on atmospheric pressure tanks built to **API Specification 12F (Specification for Shop Welded Tanks for Storage of Production Liquids)** must be in accordance with Section 4, and Appendices B and C, of **API Specification 12F (Specification for Shop Welded Tanks for Storage of Production Liquids)**. *4 - Venting Requirements* *4.1 Normal Venting* *4.2 Emergency Venting* *Appendix B – Recommended Practice for Normal Venting* *Appendix C – Recommended Relieving Capacities*			X	
	(2) Normal/emergency relief venting installed on atmospheric pressure tanks (such as those **built to API Standard 650** or its predecessor **Standard 12C**) must be in accordance with **API Standard 2000. (Venting Atmospheric and Low-Pressure Storage Tanks Nonrefrigerated and Refrigerated)**	X			
	(3) Pressure-relieving and emergency vacuum-relieving devices installed on low pressure tanks built to **API Standard 620 (Design, Construction, Large, Welded, Low-Pressure Storage Tanks)** must be in accordance with Section 9 of API Standard 620 and its references to the normal and emergency venting requirements in API Standard 2000. *Section 9 - Pressure- and Vacuum-Relieving Devices* ***9.1 Scope*** ***9.2 Pressure Limits*** ***9.3 Construction of Devices*** ***9.4 Means of Venting*** ***9.5 Liquid Relief Valves*** ***9.6 Marking*** ***9.7 Pressure Setting of Safety Devices***			X	

Comments:
GP097703

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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			S	U	N/A	N/C
	Impoundment, Protection Against Entry, Relief, and Venting Procedures-Aboveground Breakout Tanks (cont.)					
	(4)	Pressure and vacuum-relieving devices installed on high pressure tanks built to **API Standard 2510 (Design and Construction of LPG Installations):** must be in accordance with Sections 7 or 11 of API Standard 2510. *Section 7 - Tank Accessories, Including Pressure and Vacuum-Relieving* *7.1 Mandatory Equipment* *7.2 Tank Accessory Materials* *Section 11 - Refrigerated Storage*			X	
§195.402(a)	**Overpressure Safety Devices Procedures**		S	U	N/A	N/C
§195.402(c)(3)	.428(a)	Inspect and test each pressure limiting device, relief valve, pressure regulator, or other pressure control equipment. (Annually/15 mo)			X	
	.428(c)	Aboveground breakout tanks • constructed or significantly altered according to section 5.1.2 of **API Standard 2510 (Design and Construction of LPG Installations)** after October 2, 2000 must have an overfill protection system according to 5.1.2 of API Standard 2510. • **if (600 gallons or more)** constructed or significantly altered after October 2, 2000, must have overfill protection according to **API Recommended Practice 2350 (Overfill Protection for Storage Tanks in a Petroleum Facility).** *(Not required if operator notes in procedures why compliance with API RP 2350 is not necessary for tank safety).* **For Unattended Facilities (for definition, see API RP 2350, paragraph 1.3.1), Section 2.** **For Attended Facilities (for definition, see API RP 2350, paragraph 1.3.1), Section 3 and for all facilities, transfer procedures need to be per Section 4.**	X			
	.428(d)	After October 2, 2000, paragraphs (a) and (b) of §195.428 also applies for the inspection and testing of pressure control equipment and to the testing of overfill protection systems. **Subsection 4.8 of API RP 2350.**	X			
§195.402(a)	**In-service Breakout Tank Inspection Procedures**		S	U	N/A	N/C
§195.402(c)(3)	.432(a)	**Inspection Intervals (In-service tank):** Inspection of in-service breakout tanks. (annually/ 15mo) includes anhydrous ammonia and any other breakout tank that is not inspected per 432 (b) & (c); (Reference 195.1)	X			

Comments:
Subpart F; FIMMS Tank Inspection

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

§195.402(a)	In-service Breakout Tank Inspection Procedures (cont.)	S	U	N/A	N/C
	.432(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 6 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3). *Refer to API 653 Section 6.3.1; 6.3.1.1; 6.3.1.2; 6.3.1.3; 6.3.2; 6.3.2.1; 6.3.2.2; 6.3.2.3; 6.3.3.2; & 6.3.3.3*	X			
	6.4.2.2 When corrosion rates are not known and similar service experience is not available to determine the bottom plate minimum thickness at the next inspection, the actual bottom thickness shall be determined by inspection(s) within the next 10 years of tank operation to establish corrosion rates. Refer to API 653 Section 6.4; 6.4.2; 6.4.2.1; 6.4.2.2; 6.4.3; & 6.5	X			
	.432(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.			X	
	.432(d) The intervals of inspection referenced in paragraphs (b) and (c) begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier. For API 12F (Specification for Shop Welded Tanks for Storage of Production Liquids) , or its predecessor 12C, 650, and 620 tanks, the "clock" starts at the earliest of: 1) May 3, 1999, 2) Last record date of the inspection (annual), or 3) Whenever API Std 653 program was established for the particular tank.	X			
§195.402(a)	**Pressure Test Procedures/Pressure Testing Aboveground Breakout Tanks**				
	.307(a) Aboveground breakout tanks built to **API Specification 12F (Specification for Shop Welded Tanks for Storage of Production Liquids)** and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F.			X	
	.307(b) Aboveground breakout tanks built to **API Standard 620 (Design, Construction, Large Welded Low Pressure Storage Tanks)** and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 7.18 of API Standard 620.			X	
	.307(c) Aboveground breakout tanks built to **API Standard 650 (Welded Steel Tanks For Oil Storage)** and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650.	X			
	.307(d) Aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to **API Standard 650 Welded Steel Tanks For Oil Storage)** or its predecessor **Standard 12C** that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 12.3 of API Standard 653.	X			
	.307(e) Aboveground breakout tanks **built to API Standard 2510 (Design and Construction of LPG Installations)** and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.			X	

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Gp097737

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations				x
.262	Station Safety Devices				x
.308	Pre-pressure Testing Pipe - Marking and Inventory				x
.403	Supervisor Knowledge of Emergency Response Procedures				x
.410	Right-of-Way Markers				x
.412	ROW/Crossing Under Navigable Waters				x
.420	Valve Maintenance				x
.420	Valve Protection from Unauthorized Operation and Vandalism				x
.426	Scraper and Sphere Facilities and Launchers				x
.428	Pressure Limiting Devices				x
.428	Relief Valves - Location - Pressure Settings - Maintenance				x
.428	Pressure Controllers				x
.430	Fire Fighting Equipment				x
.432	Breakout Tanks				x
.434	Signs - Pumping Stations - Breakout Tanks				x
.436	Security - Pumping Stations - Breakout Tanks				x
.438	No Smoking Signs				x
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form				x
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)				x
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds				x
.575	Electrical Isolation; shorted casings				x
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)				x

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.				x
.5(c)	Pipeline Records (Life of System)				x
	Pipeline Investigations				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	Pipeline Testing				x
	Pipeline Repairs				x
	Pipeline Replacements				x
	Pipeline Alterations				x
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1 Beginning no later than June 15, 2005)				x
.52	Telephonic Reports to NRC (800-424-8802)				x
.54(a)	Written Accident Reports (DOT Form 7000-1)				x
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)				x
.56	Safety Related Conditions				x
.57	Offshore Pipeline Condition Reports				x
.59	Abandoned Underwater Facility Reports				x
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification				x
.214(b)	Test Results to Qualify Welding Procedures				x
.222	Welder Qualification				x
.234(b)	Nondestructive Technician Qualification				x
.589	Cathodic Protection				x
.266	Construction Records				x
.266(a)	Total Number of Girth Welds				x
	Number of Welds Inspected by NDT				x
	Number of Welds Rejected				x
	Disposition of each Weld Rejected				x
.266(b)	Amount, Location, Cover of each Size of Pipe Installed				x
.266(c)	Location of each Crossing with another Pipeline				x
.266(d)	Location of each buried Utility Crossing				x
.266(e)	Location of Overhead Crossings				x
.266(f)	Location of each Valve and Test Station				x
	PRESSURE TESTING				
.310	Pipeline Test Record				x
.305(b)	Manufacturer Testing of Components				x
.308	Records of Pre-tested Pipe				x
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (1 per yr/15 months)				x
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions				x
.402(c)(10)	Abandonment of Facilities				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials				x
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures				x
.402(d)(1)	Response to Abnormal Pipeline Operations				x
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures				x
.402(e)(1)	Notices which require immediate response				x
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency				x
.402(e)(9)	Post Accident Reviews				x
.403(a)	Emergency Response Personnel Training Program				x
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)				x
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures				x
.404(a)(1)	Maps or Records of Pipeline System				x
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines				x
.404(a)(3)	MOP of each Pipeline				x
.404(a)(4)	Pipeline Specifications				x
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)				x
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)				x
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)				x
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)				x
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)				x
.406(a)	Establishing the MOP				x
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.				x
.412(a)	Inspection of the ROW				x
.412(b)	Inspection of Underwater Crossings of Navigable Waterways				x
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk				x
.420(b)	Inspection of Mainline Valves				x
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)				x
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).				x
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)				x
.430	Inspection of Fire Fighting Equipment				x
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).				x
.440	Public Education/Awareness Program				x
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators				x
.442(c)(2)	Notification of Public/Excavators				x
.442(c)(3)	Notifications of planned excavations. (One -Call Records)				x
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.				x

Form-3 Standard Inspection Report of a Liquid Pipeline Carrier (Rev. 03/02/07 through Amdt. 195-86).

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.589(c)/.567	Test Lead Maintenance, frequent enough intervals				x
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)				x
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests **(1 per yr/15 months)**				x
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)				x
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3 cal yr/39 months)**				x
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers				x
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks				x
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).				x
.589(c)/.575	Electrical isolation inspection and testing				x
.589(c)/.577	Testing for Interference Currents				x
.589(c)/.579(a)	Corrosive effect investigation				x
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/7½ months)**				x
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion				x
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**				x
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG				x
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP				x
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)				x

Comments:
No records or field reviews were performed

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]			x
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			x
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			x
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]			x
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]			x

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

OPA Inspection Guidance

OPA-1 - **RSPA Tracking Number**: This is also known as the "sequence number." It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

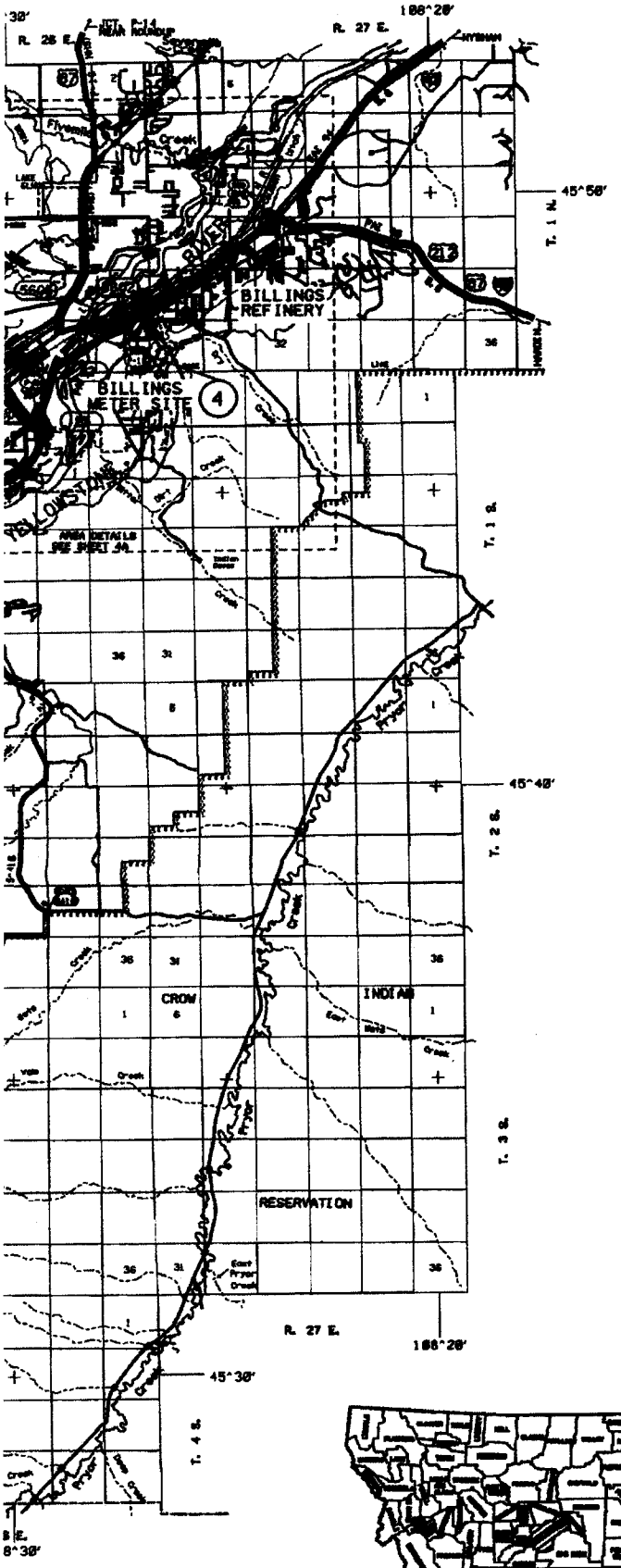
Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

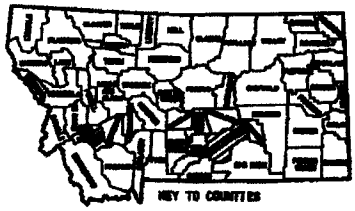
OPA-2 - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - **Proof of OSRO contract**: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.





KEY TO COUNTIES

LEGEND

- National Boundary
- State Boundary
- County Boundary
- Other Boundaries
- Defended Area Boundary
- Township Line
- Section Line
- Continental Divide
- Large River
- Intermediate River
- Small River
- Intermittent Stream
- Irrigation Canal with Flow Direction
- Reservoir with Dam
- Lake or Reservoir - Overflow Land
- Marsh - Glacier
- Elevation of Mountain Peak
- Primitive Road - Graded Road
- Graded Road - Gravel Road
- Paved Road - Divided Highway
- Numbered National Interstate Highway
- U.S. Numbered Highway
- State Numbered Highway (2-4 Digits)
- Primary System
- Secondary System
- Urban Route Number
- Bad Designated Route
- Mile Distances Between Points
- Interchange - Grade Separation
- Dam with Road
- Highway Bridge - Number Closely Spaced
- Toll Ferry - Free Ferry
- Named Pass with Elevation
- Railroad - Railroad with Station
- Railroad above Grade - Railroad below Grade
- Grade Crossing - Railroad Tunnel
- Airport with Surfaced Runways
- Airway Light Beacon
- Military Field
- Airport, Complete Facilities
- Airfield, Limited Facilities
- Landing Area or Strip
- State Capital - County Seat
- Other Towns - Corporate Limits
- School - Church
- Cemetery - Cemetery with Church
- Post or Military Post - Courthouse
- Post Office - U.S. Port of Entry
- Hospital - Prehistoric
- Radio Station - Industry
- Power Plant - Power Substation
- Summit - Mine
- Oil or Gas Well - Oil Storage Tank
- Gauging or Pumping Station
- Gas Storage Tank - Water Storage Tank
- Picnic Grounds - Camp Grounds
- Rest Area - Ski Area
- Hot Spring - Triangulation Station
- Ranger Station - Lookout Tower
- Fairgrounds - Fish Hatchery
- Grain Elevator - State or County Map

MONTANA

YELLOWSTONE COUNTY

PREPARED BY THE

STATE OF MONTANA
DEPARTMENT OF TRANSPORTATION

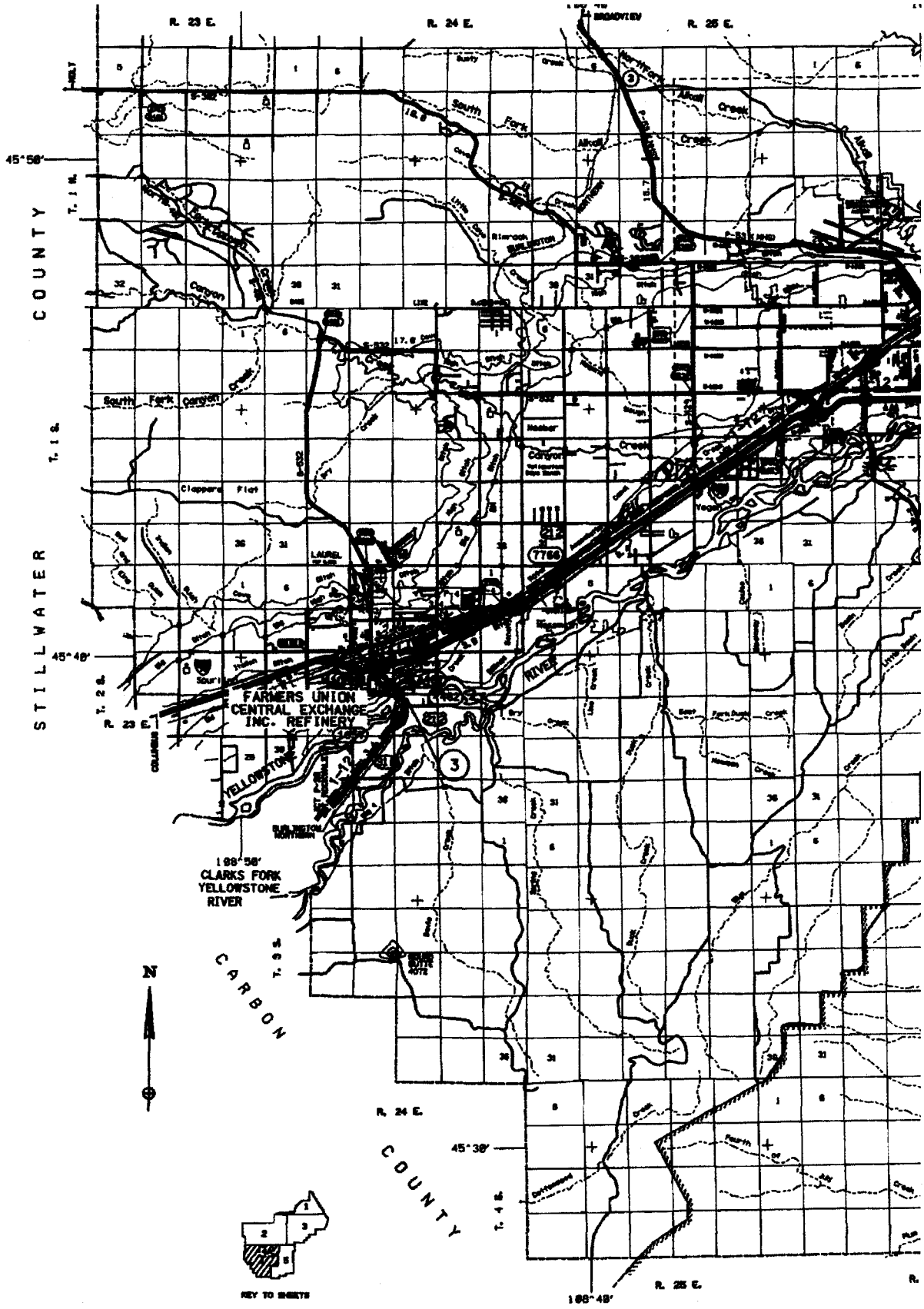
IN COOPERATION WITH THE
U.S. DEPARTMENT OF TRANSPORTATION
FEDERAL HIGHWAY ADMINISTRATION

COUNTY

REVISIONS
On System
Local System (Partial) 10-19-92
08-22-96

SCALE
0 1 2 3 4 5 MILES

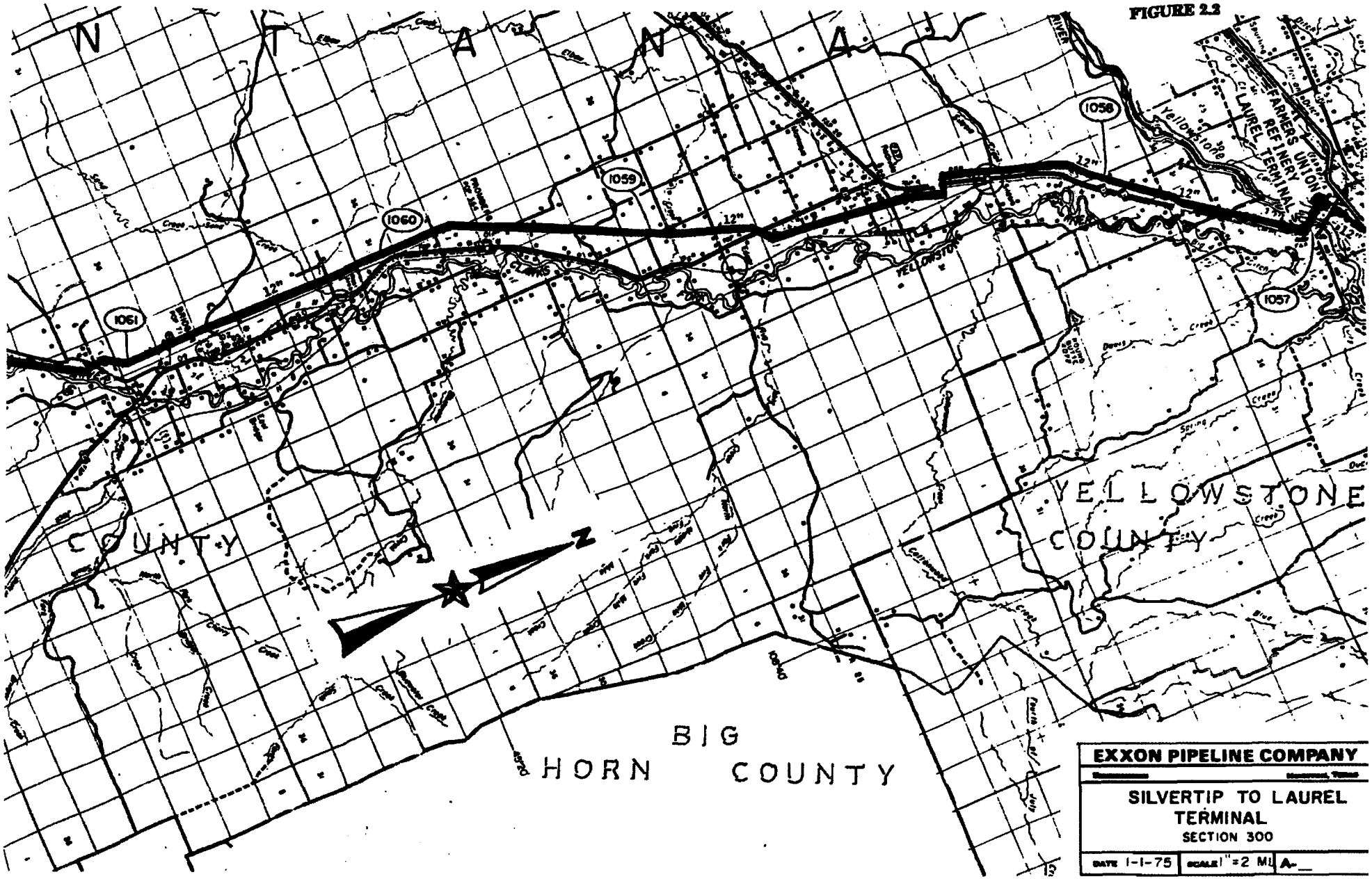
BASE MAP COMPILED 1981



LAMBERT CONFORMAL CONIC
NORTH AMERICAN DATUM - 1983

COPYRIGHT 1991 MONTANA DEPARTMENT of TRANSPORTATION

FIGURE 2.2



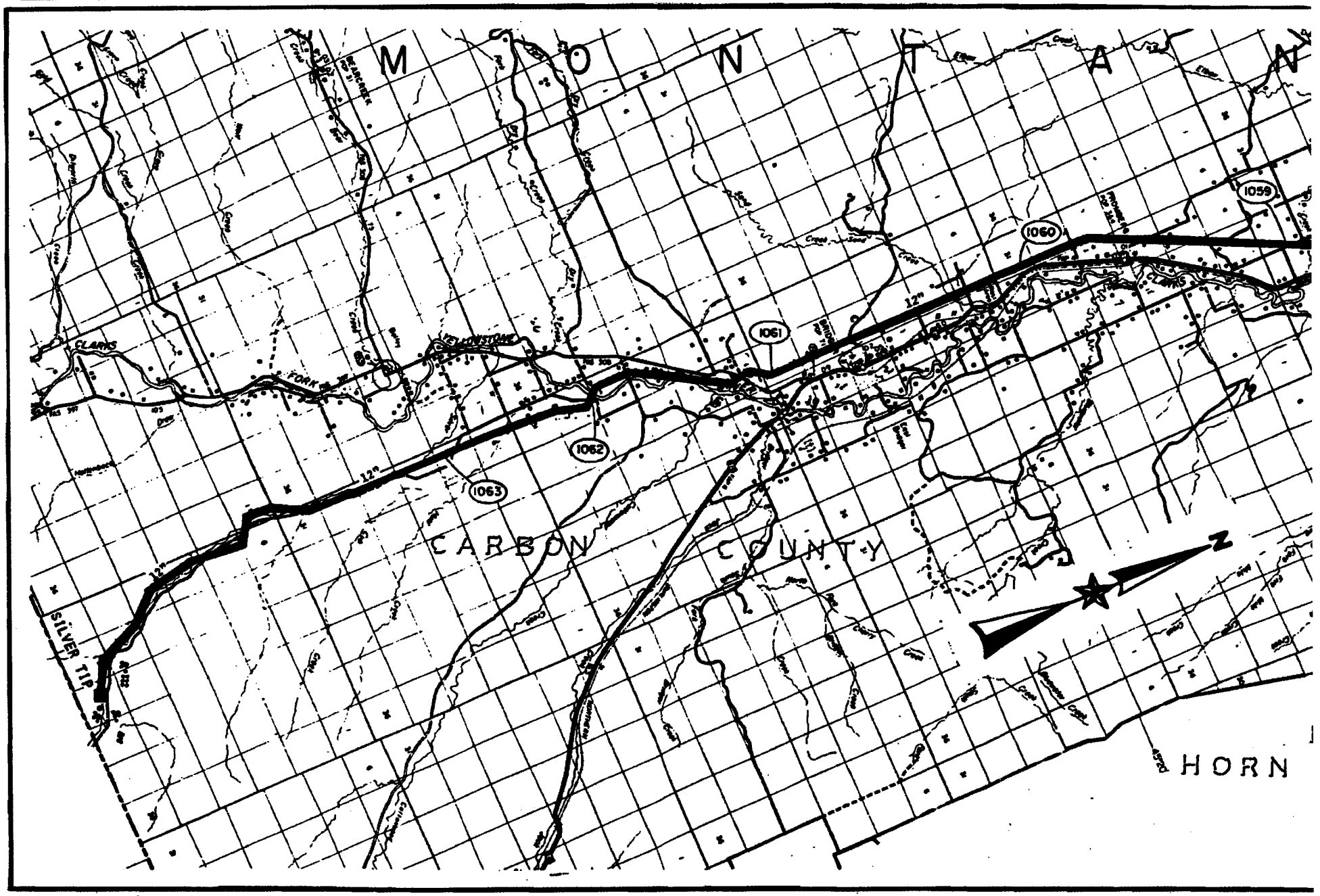
EXXON PIPELINE COMPANY

Houston, Texas

SILVERTIP TO LAUREL TERMINAL

SECTION 300

DATE 1-1-75 | SCALE 1" = 2 MI | A-__


M O N T A N
1059
1060
1061
1062
1063
12"
CLARKS
FORK
SILVER TIP
CARBON COUNTY
HORN

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 2, 2007

Mr. Patrick Doolan
Vice President
ExxonMobil Pipeline Company
800 Bell Street
Houston, Texas 77002

CPF 4-2007-5029W

Dear Mr. Parker:

During April 9-13, 2007; April 23-27, 2007; and May 7, 2007 representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your Hazardous Liquid Integrity Management Program in Houston, TX.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§195.452 Pipeline integrity management in high consequence areas.**

   (h) What actions must an operator take to address integrity issues?

   (3) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.

   ExxonMobil Pipeline Company (EMPCo) documented a decision to not repair an anomaly on the Grand Isle Block 22L to Grand Isle Terminal segment meeting 180-day rule repair criteria without notifying PHMSA or obtaining regulatory relief from PHMSA through the waiver process. The Inspection Team noted that EMPCo developed draft material for

technical justification that indicated the segment of pipeline containing the anomaly could not affect an HCA. However, formal re-evaluation of whether the segment could affect an HCA was not fully pursued and documented in sufficient detail to establish this position.

PHMSA recognizes that some operators used methods with conservative assumptions in identifying which pipeline segments can affect HCAs to meet the initial compliance deadline. Refinement of these "could affect segments", potentially changing the boundaries of identified segments, may occur as more detailed analyses are performed. This refinement process could result in conclusions that some segments (or portions of segments) identified by the initial deadline cannot affect an HCA. PHMSA expects operators to document their justification for any such elimination of an identified segment, and may review the technical basis for these changes during inspections.

Operators should not, however, apply refinements which impact the determination of whether a segment can affect an HCA once the process of conducting an integrity assessment for that segment has begun. The integrity assessment results must be evaluated, and repairs required by the criteria of paragraph (h) must be performed, for the entire segment as defined prior to conduct of the assessment. The boundaries of the segment can be reconsidered after conclusion of an integrity assessment and repair process.

2. **§195.49 Annual report**

   Beginning no later than June 15, 2005, each operator must annually complete and submit DOT form RSPA 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.

   Included in the integrity assessment data reviewed by the Inspection Team were anomalies that met immediate repair criteria and were remediated as part of confirmatory digs within a short period of time but were not classified as immediate conditions. The classification of these anomalies as "confirmatory digs" rather than "immediate conditions" in EMPCo's internal tracking system results in a failure to accurately trend and report anomalies that meet the immediate repair criteria. EMPCo should ensure that immediate conditions are identified as such and included in data that is required to be annually transmitted to PHMSA.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the items identified in this letter. Failure to do so will result in EMPCo being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 4-2007-5029W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions

you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 9, 2007

Mr. John DuPre
Vice President – Operations, Northern
ExxonMobil Pipeline Company
3225 Gallows Road
Fairfax, VA 22037

SENT TO COMPLIANCE REGISTRY
Hardcopy__ Electronically ✓
# of Copies 1 / Date 1/9/07

CPF 5-2007-5001W

Dear Mr. DuPre:

On June 20 to June 22, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected your Silvertip Pipeline in south central Montana.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

ExxonMobil Pipeline Company's (EMPCo's) cathodic protection monitoring procedures state "The annual pipe-to-soils shall be plotted and compared to the last three years. When a significant drop in potential is noted, further investigation should be scheduled to identify the cause." Review of EMPCo's pipe-to-soil records for the Silvertip Pipeline in 2005 show that several locations along this pipeline had pipe-to-soil readings significantly below the previous

three years' readings. In fact several locations show a trend toward lower levels of cathodic protection. There had been no further investigation to determine the cause.

2. **§195.410 Line markers.**

(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

At the time of this inspection there were no pipeline markers at the Peterson road crossing at MP 54.8.

3. **§195.422 Pipeline Repairs.**

(a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.

EMPCo's in-service fillet and groove weld procedures, qualified in 1974, do not have the number and/or type of qualification destructive tests that are required under the accepted industry practice for qualifying in-service welds (API 1104 Appendix B).

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violations persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Be advised that failure to do so will result in ExxonMobil Pipeline Company being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2007-5001W.**

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 (G. Davis # 116697)

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 20, 2007

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, Texas 77002

CPF 4-2007-5032M

Dear Mr. Pruessing:

On April 2-6, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected ExxonMobil Pipeline Company's (EMPCO) procedures for Operations and Maintenance in Houston, Texas.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within ExxonMobil's plans or procedures, as described below:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

   (a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

EMPCO procedures need to specify that appropriate parts of the Procedural Manual will be made available at locations where O&M activities are conducted. Also, procedures need to specify how Procedural Manual annual reviews will be documented.

2. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

A. **§195.230 Welds: Repair or removal of defects.**

(b) 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.

EMPCO procedures need to specify that after a repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

B. **§195.264 Aboveground breakout tanks.**

(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

(1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:
(i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2; and
(ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1.

EMPCO procedures need to specify that all DOT regulated breakout tanks must follow NFPA 30 for impoundment requirements.

C. **§195.404 Maps and Records.**

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information;

(1) Location and identification of the following pipeline facilities;

(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c)(9) applies;
(vi) Rights-of-way; and
(vii) Safety devices to which §195.428 applies.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

EMPCO procedures need to specify that scraper and sphere facilities, facilities that are not equipped to fail safe in immediate response areas and rights-of-way will be identified on current company maps. Also, the procedures need to specify the company will maintain current maps and records identifying rivers, buried utilities and foreign pipelines.

D. **§195.404 Maps and Records.**

(c) Each operator shall maintain the following records for the periods specified;
3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

EMPCO procedures need to specify that monthly tank inspection records will be maintained for 2 years or until the next inspection or test, whichever is longer.

E. **§195.406 Maximum operating pressure.**

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with §195.106. However, for steel pipe in pipelines being converted under §195.5, if one or more factors of the design formula (§195.106) are unknown, one of the following pressures is to be used as design pressure:
(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factors in §§195.106(a) and (e); or
(ii) If the pipe is 323.8 mm (12¾ in) or less outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig).

(2) The design pressure of any other component of the pipeline.

(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Subpart E of this part.

(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §195.305.

(5) For pipelines under §§195.302(b)(1) and (b)(2)(i), that have not been pressure tested under Subpart E of this part, 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.

EMPCO procedures only state that the Maximum Operating Pressure (MOP) will be calculated by use of the design equation and doesn't specify that except for surge pressures or other variations from normal operations, the MOP may not exceed (a)(2)-(a)(5).

F. §195.406 Maximum operating pressure.

(b) 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 paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

EMPCO procedures need a reference to Design GP/Local Operating Instructions for operation constraints and to specify in the DOT Liquid Manual that adequate controls and protective equipment must be installed to prevent the pressure from exceeding 110% of the MOP.

G. §195.408 Communications.

(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:

(4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

EMPCO procedures need to reference and/or specify all forms of communication that can be utilized during emergencies, including natural disasters.

H. §195.410 Line markers.

(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

EMPCO Procedures need to be more descriptive for placement of line markers along the right-of-way to ensure that the location of the pipelines is accurately known.

I. §195.420 Valve maintenance.

(c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

EMPCO procedures need to reference Appendix E Security Guidelines of the DOT Liquid Manual to specify how valves will be protected from vandalism.

J. **§195.428 Overpressure safety devices and overfill protection systems**

(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

EMPCO procedures need to be more descriptive on what steps are taken to validate inspections of overpressure protection provided by a third party operator.

K. **§195.430 Firefighting equipment.**

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be-

(a) In proper operating condition at all times;
(b) Plainly marked so that its identity as firefighting equipment is clear; and,
(c) Located so that it is easily accessible during a fire.

EMPCO procedures need to specify how the operator determines that adequate firefighting equipment is provided for each pump station and breakout tank area.

L. **§195.438 Smoking or open flames.**

Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

EMPCO procedures need to reference 195.410(6) pg 149 of the DOT Liquids Manual for placement of "No Smoking" signs.

M. **§195.442 Damage Prevention Program**

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary markings to be provided and how to identify the markings.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
(ii) In the case of blasting, any inspection must include leakage surveys.

EMPCO procedures need to specify that an excavator will be notified of the type of temporary markings used and how to identify the marking. Also, the procedures need to specify that after blasting, a leakage survey will be conducted if the operator has reason to believe the pipeline could be damaged by the blasting activities.

N. §195.559 What coating material may I use for external corrosion control?

Coating material for external corrosion control under Sec. 195.557 must--

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;
(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
(c) Be sufficiently ductile to resist cracking;
(d) Have enough strength to resist damage due to handling and soil stress;
(e) Support any supplemental cathodic protection; and
(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

EMPCO procedures need to reference coating testing documents and/or specify what coating material specifications are required for external corrosion control.

O. §195.561 When must I inspect pipe coating used for external corrosion control?

(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

EMPCO procedures for electronic inspection of coatings need to be more detailed to ensure that correct voltage settings for holiday detection are utilized for different coating types and thicknesses.

P. §195.569 Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate 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.

EMPCO procedures need to specify that if external corrosion is found requiring corrective action, the pipe must be investigated *circumferentially and longitudinally* beyond the exposed portion to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

Q. §195.579 What must I do to mitigate internal corrosion?

(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

EMPCO procedures need to specify that if internal corrosion is found requiring corrective action, the pipe must be investigated *circumferentially and longitudinally* beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed portion.

R. **§195.583 What must I do to monitor atmospheric corrosion control?**

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by Sec. 195.581.

EMPCO procedures need to specify repair criteria that will provide protection against corrosion and ensure that any problems discovered during inspections for atmospheric corrosion are corrected.

3. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(8) In the case of pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406.

EMPCO procedures need to define fail safe as is pertains to operations of the pipeline systems.

4. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

(e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs;

(6) Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

(7) Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid.

EMPCO procedures need to include railroad traffic closure in affected areas when minimizing public exposure during hazardous liquid emergencies. Also, procedures need to reference Section 5 of the Emergency Manual for notifications to emergency and public officials.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2007-5032M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

Facsimile

ExxonMobil
Pipeline

Date: 9/6/2007

Subject: DOT - Notice of Amendment Letter Dated 9/6/2007 Request 60-Day Extension

Pages: - 2- Including Cover)

To: Office of Pipeline Safety
Attn: Rodrick M. Seeley

Telephone: 713.272.2859
Facsimile: 713.272.2831

Urgent
☐ Please Comment / Reply

From: Kevan G. McCrae

☐ FYI / Please Recycle
Copy To:

Telephone: 713.656.0227
Facsimile: 713.656.8232

Message:

Certified Mail # 7000 1670 0005 2351 1150

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ExxonMobil Pipeline Company
800 Bell Street, Room 603B
Houston, Texas 77002

An ExxonMobil Subsidiary

09-06-07 15:39 Pg: 1

Fax from : 713 656 8232

ExxonMobil Pipeline Company
800 Bell Street - (PL-EMB-6038)
Houston, Texas 77002
713 656 0227 Telephone
713 656 8232 Facsimile

K. G. (Kevan) McCrae
Manager
Safety, Health And Environment Department

ExxonMobil Pipeline

September 6, 2007

Sent Via Facsimile and
Certified Mail # 7000 1670 0005 2351 1150
Return Receipt Requested

Rodrick M. Seeley
Director, Southwest Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation
8701 Gessner, Suite 1110
Houston, Texas 77074

Re: DOT-OPS File Number CPF No. 4-2007-5032M
Notice of Amendment
Request for 60-Day Extension

Dear Mr. Seeley:

ExxonMobil Pipeline Company (EMPCo) respectfully requests a 60-day extension on the subject PHMSA Notice of Amendment, received August 23, 2007. The proposed new deadline would be Monday, October 22, 2007.

While most procedural amendments are straightforward, some will require multi-department and cross functional discussions. Additionally, the documentation of revised procedures will require appropriate levels of internal review and approval. Therefore an extension is needed.

If you have any questions or would like to discuss, please contact me at 713-656-0227 or Cathey Casey at 713-656-6913.

Sincerely,

Kevan McCrae

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 28, 2007

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, Texas 77002

RE: Request for Time Extension - Response to Notice of Amendment (NOA) letter dated August 20, 2007, for CPF 4-2007-5032M

Dear Mr. Pruessing:

ExxonMobil Pipeline Company submitted a letter dated September 6, 2007 regarding the referenced NOA requesting a time extension until October 22, 2007 for the actions required for amending the deficient procedures noted in the referenced NOA.

We have reviewed your request and grant the extension for all issues in the NOA until October 22, 2007 in order to ensure that there is adequate time for revisions to the processes and procedures and appropriate internal technical review of the revisions noted in **CPF 4-2007-5032M**.

Sincerely,

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Facsimile

ExxonMobil
Pipeline

Date: 10/22/2007

Subject: DOT - Notice of Amendment Letter Dated 10/22/2007- Rodrick Seeley

Pages: - 24- (Including Cover)

To: Office of Pipeline Safety
Attn: Rodrick M. Seeley

Telephone: 713.272.2859
Facsimile: 713.272.2831

Urgent
☐ Please Comment / Reply

From: Kevan G. McCrae

☐ FYI / Please Recycle
Copy To:

Telephone: 713.656.0227
Facsimile: 713.656.8232

Message:

Certified Mail # 7000 1670 0005 2350 8457

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ExxonMobil Pipeline Company
800 Bell Street, Room 603B
Houston, Texas 77002

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ExxonMobil Pipeline Company
800 Bell Street - (PL-EMB-603B)
Houston, Texas 77002
713 656 0227 Telephone
713 656 8232 Facsimile

K. G. (Kevan) McCrae
Manager
Safety, Health And Environment Department

ExxonMobil
Pipeline

October 22, 2007

Sent Via Facsimile and
Certified Mail # 7000 1670 0005 2350 8457
Return Receipt Requested

Rodrick M. Seeley
Director, Southwest Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
U. S. Department of Transportation
8701 Gessner, Suite 1110
Houston, Texas 77074

Re: DOT-OPS File Number CPF No. 4-2007-5032M
Notice of Amendment
EMPCo Operations and Maintenance Procedure Revisions

Dear Mr. Seeley:

Representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected ExxonMobil Pipeline Company's (EMPCo) procedures for Operations and Maintenance in Houston, Texas during April 2007. On August 23, 2007, EMPCo received a Notice of Amendment (NOA) letter from PHMSA. EMPCo requested and PHMSA granted a 60-day deadline extension. The actual new deadline should have been named November 22, 2007. However, EMPCo erroneously named and PHMSA approved a deadline of October 22, 2007.

EMPCo has drafted procedural revisions and enhancements and requests PHMSA approval. Generally, the response is organized such that PHMSA items precede EMPCo's drafted procedures. The source document of each EMPCo draft procedure is named, with additional explanations and attachments in some cases. It is EMPCo's plan to implement upon PHMSA's approval.

PHMSA

1. §195.402 Procedural manual for operations, maintenance, and emergencies.

(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary

to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

EMPCo procedures need to specify that appropriate parts of the Procedural Manual will be made available at locations where O&M activities are conducted. Also, procedures need to specify how Procedural Manual annual reviews will be documented.

EMPCo Response
DOT Liquid Manual; procedures follow §195.402 (a), p. 111; added underlined portions.

The Safety, Health & Environment Department (SHE) is responsible for the annual review and appropriate revisions of this Manual. The Annual Review and any revisions are documented via the Log of Revisions contained herein. If significant procedural changes are being considered, a Team of internal experts is convened. Staff from Engineering, Field Ops, SHE, OCC, IMP, and/or others will participate as appropriate. System operating instructions and local procedures are the responsibility of the department or operating area which initially prepared them. Other referenced materials are the responsibility of the department which initially prepared them.

The primary administrative responsibility for compliance with the instructions and procedures in this manual is assigned to Company's Field Operations Department and the Field Operations Area Supervisors. The Manual is available electronically or in hardcopy to all Field Operations employees who work on DOT facilities, consistent with Company's Operations Integrity Management System "4A-Information and Documentation" procedures.

PHMSA

2. ***§195.402 Procedural manual for operations, maintenance, and emergencies.***

   (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
   (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

   A. ***§195.230 Welds: Repair or removal of defects.***

      (b) 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.

EMPCo procedures need to specify that after a repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

EMPCo Response
DOT Liquid Manual; procedures follow §195.230 -.234, p. 87, added underlined section.

PROCEDURE:
Refer to **ExxonMobil Pipeline Repair and Modification Manual**-Section 6, and **Welding Manual.**

Pipeline Repair and Modifications Manual; added underlined sentence to Section 6.5, Other Welding Repairs, p. 53:

If repair does not pass inspection and must be repaired again, additional inspections will be required until the repair is acceptable.

PHMSA

B. §195.264 Aboveground breakout tanks.

(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

(1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:

(i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2;and

(ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1.

EMPCo procedures need to specify that all DOT regulated breakout tanks must follow NFPA 30 for impoundment requirements.

EMPCo Response
DOT Liquid Manual; procedures follow §195.264, p. 94, added underlined section:

Refer to **Global Engineering Practices (GP) 04-77-15 Tank Field Dike Design** and **GP 77-77-04 Terminal Layout and Spacing.**

Explanation: These two Global Practices contain written cross references to each other; - GP 77-77-04 contains reference to NFPA 30. Thus by reference, NFPA 30 is also part of GP 04-77-15. Note EMPCo does not differentiate a marketing "terminal" from a pipeline "terminal". See GP info immediately below.

GP 04-77-15 Excerpts
Scope

This Global Practice (GP) covers design of containment dikes and walls for atmospheric storage tanks.

GP 77-77-04 Excerpts

Scope

This Global Practice (GP) presents considerations and requirements for the layout and spacing of equipment for new terminals and the modification of existing terminals. It covers the relationship between individual terminal areas, equipment, and property lines of the surrounding community. It also covers tank dike arrangements and mandatory safety requirements governing the layout and spacing of atmospheric storage tanks that are designed for operation at 2.5 psig or less containing flammable and combustible liquids.

Section 1.3 - NFPA–National Fire Protection Association

NFPA 30	Flammable and Combustible Liquids Code

Section 5.3.

3. Existing terminals are governed by NFPA 30, Tankage, and GP 04-77-15.
4. For new terminals, diking around tanks shall comply with the NFPA 30, GP 04-77-15.

PHMSA

C. §195.404 Maps and Records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information;

(1) Location and identification of the following pipeline facilities;
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c)(9) applies;
(vi) Rights-of-way; and
(vii) Safety devices to which §195.428 applies.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

EMPCo procedures need to specify that scraper and sphere facilities, facilities that are not equipped to fail safe in immediate response areas and rights-of-way will be identified on current company maps. Also, the procedures need to specify the company will maintain current maps and records identifying rivers, buried utilities and foreign pipelines.

EMPCo Response

DOT Liquid Manual, procedure follows §195.404, p. 142; added underlined text:

PROCEDURES:

Field Operations shall maintain current maps and construction, testing, and operating records of each pipeline system. Supervisors responsible for the local operation of pipeline facilities will be furnished the necessary maps, drawings, and other information required to ensure proper and safe operation and ensure the expeditious location of company facilities when time is a factor.

These include (as appropriate):

- County road maps showing location and identification of Company's pipeline facilities,
- Trunk Line Charts, Alignment Drawings, and/or As-Builts, road, railroad, river, foreign pipeline, and underground utility crossings,
- Line Diagrams of Stations/Terminals,
- Field Inventory Maps, breakout tanks, pump stations, pipeline block valves, traps, safety devices, etc.,
- Facilities that are not equipped with over pressure protection (failsafe),
- Equipment manuals - Outlining operating instructions for major items when necessary.

PHMSA

D. §195.404 Maps and Records.

(c) Each operator shall maintain the following records for the periods specified;
3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer

EMPCo procedures need to specify that monthly tank inspection records will be maintained for 2 years or until the next inspection or test, whichever is longer.

EMPCo Response

1. DOT Liquid Manual, procedure follows §195.404, p. 143; added underlined text:

Field Operations shall maintain inspection and test records for at least 2 years or until the next inspection or test is performed, whichever is longer, for the following:
Monthly and 12-month inspection of breakout tanks

2. Monthly Tank Inspection Form, added underlined text to form:

NOTE: Document to be retained 2 years or until next inspection, whichever is longer

PHMSA

E. §195.406 Maximum operating pressure

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with §195.106. However, for steel pipe in pipelines being converted under §195.5, if one or more factors of the design formula (§195.106) are unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME831.8, reduced by the appropriate factors in §§195.106(a) and (e); or

(ii) If the pipe is 323.8mm(123/4in) or less outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig).

(2) The design pressure of any other component of the pipeline.

(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Subpart E of this part.

(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §195.305.

(5) For pipelines under §§195.302(b)(1)and (b)(2)(i), that have not been pressure tested under Subpart E of this part, 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.

EMPCo procedures only state that the Maximum Operating Pressure (MOP) will be calculated by use of the design equation and doesn't specify that except for surge pressures or other variations from normal operations, the MOP may not exceed (a)(2)-(a)(5).

EMPCo Response

DOT Liquid Manual, added underlined paragraph to existing procedures that follow §195.406, p. 145-146:

Other than surge pressures or other variations from normal operations, EMPCo pipelines will not be operated at pressures greater than:

1. the internal design pressure of the pipe as described in 195.106
2. design pressure of components/appurtenances
3. 80% of certified test pressure
4. 80% of factory test pressure or manufacturer prototype test pressure of any individually installed component
5. 80% of test pressure or highest 4 hour operating pressure

PHMSA

F. §195.406 Maximum operating pressure.

(b) 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 paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

EMPCo procedures need a reference to Design GP/Local Operating Instructions for operation constraints and to specify in the DOT Liquid Manual that adequate controls and protective equipment must be installed to prevent the pressure from exceeding 110% of the MOP.

EMPCo Response

1. DOT Liquid Manual, procedure follows §195.406, p. 146; added underlined text.

Field Operations must ensure that systems are not operated so as to exceed their MOP's during normal operations. Devices such as control valves, high pressure shutdown switches, and other protective devices for maintaining safe operating pressures will be utilized to prevent pressure from exceeding 110% of MOP on pipeline systems.

OCC and local operating instructions are available to assist in operating the pipeline systems at pressures below the MOP of the line. The instructions list the pressure control setpoints for all pressure control devices and overpressure protection devices.

2. DOT Liquid Manual, procedure added at end of §195.406, p. 148; underlined text

For additional information on establishment of MOP, refer to **Global Practices 59-01-01, Onshore Design**, and/or **86-01-01, Offshore Design**.

PHMSA

G. §195.408 Communications.

(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:

(4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

EMPCo procedures need to reference and/or specify all forms of communication that can be utilized during emergencies, including natural disasters.

EMPCo Response

1. DOT Liquid Manual, procedure added after §195.408, p. 149; underlined text

The **Emergency Core Manual, Volume** I contains additional emergency communication information.

2. EMPCo Core Emergency Plan, Volume I, Section 7, p. 2, Communications; added underlined text.

GETS and WPS

EMPCo also has access to the Government Emergency Telecommunications Service (GETS) and the Wireless Priority Service (WPS) for certain individuals in key positions around the EMPCo Operations Areas. These two Government provided services give EMPCo access to hardwire and wireless communications systems in times of disasters when normal access to communications is overwhelmed with high communications traffic.

PHMSA

H. §195.410 Line markers.

(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:
(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

EMPCo Procedures need to be more descriptive for placement of line markers along the right-of-way to ensure that the location of the pipelines is accurately known.

EMPCo Response

DOT Liquid Manual, procedure follows §195.410, p. 151; added underlined text:

(1) Buried and Aboveground Piping

Where practical, such markers will be placed in 'line of sight' locations on the pipeline route to identify the buried and aboveground piping accessible to the public, as well as in other locations described below.

Line Markers are not required in heavily developed urban areas, such as downtown business centers, where the placement of markers is impracticable and would not serve the purpose for which they are intended. In addition, markers are not required in areas where the local government maintains current substructure records, offshore or at crossings of or under waterways and other bodies of water.

(2) Road and Rail Crossings

Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known. Casing vents will be identified by use of casing vent cap markers. Where pipelines are in parallel encroachment of streets or highways, markers or warning signs shall be installed at reasonable intervals along the pipeline.

PHMSA

I. §195.420 Valve maintenance.

(c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

EMPCo procedures need to reference Appendix E Security Guidelines of the DOT Liquid Manual to specify how valves will be protected from vandalism.

EMPCo Response
DOT Liquid Manual, procedure revised. Deleted and inserted paragraphs are included below. They follow(ed) §195.420, p. 158:

Old-deleted

~~Locking a valve provides adequate protection from unauthorized operation. Field Operations should assess the probability of vandalism for each of its valves and provide required protection.~~

New-added

Field Operations should assess the probability of unauthorized operation and / or vandalism of its valves by utilizing the Valve Risk Assessment, and provide additional protection as appropriate in accordance with Appendix E - Security Guidelines.

PHMSA

J. §195.428 Overpressure safety devices and overfill protection systems

(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 1/2 months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

EMPCo procedures need to be more descriptive on what steps are taken to validate inspections of overpressure protection provided by a third party operator.

EMPCo Response
DOT Liquid Manual, procedure added after §195.428, p. 165; underlined text

Where pipeline pressure is provided by others, EMPCo will verify that pressure protection is provided and that regulatory required inspections are completed as necessary. If pressure protection is achieved by limiting the size of a pump, EMPCo will request a copy of data verifying maximum pump pressure cannot overpressure the pipelines.

PHMSA

K. §195.430 Firefighting equipment.

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be-

(a) In proper operating condition at all times;
(b) Plainly marked so that its identity as firefighting equipment is clear; and,
(c) Located so that it is easily accessible during a fire.

EMPCo procedures need to specify how the operator determines that adequate firefighting equipment is provided for each pump station and breakout tank area.

EMPCo Response
DOT Liquid Manual, procedure revised after §195.430, p. 168; added underlined text:

Operations shall be responsible for maintaining adequate firefighting equipment at each station and breakout tank area. The extent of portable firefighting equipment available for use by EMPCo employees is intended for incipient stage fire suppression. The selection, placement, inspection and maintenance of firefighting equipment are based on NFPA 10, Standard for Portable Fire Extinguishers, and OSHA 1910.157, Portable Fire Extinguishers, to ensure reliability and availability appropriate for the fire hazard. Normally fire extinguishers will be installed at the entrance to each station, in every control building, by any pump unit, and positioned at various locations inside breakout tank areas. All extinguishers are to be plainly marked so that its identity as firefighting equipment is clear. Operations shall establish schedules for routine inspection of firefighting equipment to ensure that it is in proper operating condition at all times. Such inspections shall be documented and records maintained.

The design, installation, inspection and maintenance of fixed fire protection equipment, i.e. foam systems, for breakout storage tanks so equipped are based on NFPA 11, Standard for Low-, Medium-, and High-Expansion Foam, and OSHA 1910.163, Fixed Extinguishing Systems, Water Spray, and Foam.

Refer to EMPCo Safety Manual, Section II-Fire Safety for inspection frequency.

PHMSA

L. §195.438 Smoking or open flames.

Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

EMPCo procedures need to reference 195.410(6) pg 149 of the DOT Liquids Manual for placement of "No Smoking" signs.

EMPCo Response
DOT Liquid Manual, procedure added after §195.438, p. 173; underlined text:

PROCEDURES:

Appropriate signs shall be posted at each location or area where smoking and open flames are prohibited. For additional information on placement of "No Smoking" signs, refer to procedures in this manual at 195.410.

PHMSA

M. §195.442 Damage Prevention Program

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary markings to be provided and how to identify the markings.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
(ii) In the case of blasting, any inspection must include leakage surveys.

EMPCo procedures need to specify that an excavator will be notified of the type of temporary markings used and how to identify the marking. Also, the procedures need to specify that after blasting, a leakage survey will be conducted if the operator has reason to believe the pipeline could be damaged by the blasting activities.

EMPCo Response
DOT Liquid Manual references One Call Procedures Manual. One Call Procedures Manual, p. 6, added underlined text:

1. Line Marking
Temporary pipeline markers are reviewed with excavator's competent person on-site and documented using the Third Party Excavation Safe Work Checklist with copy provided to the Excavator.

2. Third Party Excavation Safe Work Checklist, p. 3 - EMPCo original, and p. 4- Excavator copy, added Item 7:

EMPCo pipeline has been marked with wooden stakes, wire flags, paint or other means in conjunction with color-coded flagging.

DOT Liquid Manual, revised procedures after 195.442, p. 179, added underlined text:

(c)(6) Blasting within 500 feet of EMPCo's pipelines requires review and advance approval of contractor blasting plan in order to prevent damage to EMPCo facilities. A leak survey will be conducted and documented after such blasting as part of EMPCo's closure of one call ticket.

PHMSA

N. §195.559 What coating material may I use for external corrosion control?

Coating material for external corrosion control under Sec. 195.557 must--

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;
(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
(c) Be sufficiently ductile to resist cracking;
(d) Have enough strength to resist damage due to handling and soil stress;
(e) Support any supplemental cathodic protection; and
(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

EMPCo procedures need to reference coating testing documents and/or specify what coating material specifications are required for external corrosion control.

EMPCo Response
DOT Liquid Manual, added paragraph following §195.559, p. 208, underlined text:

Pipeline coatings used for external corrosion control are typically fusion- bonded epoxies. These epoxy coatings are applied, inspected, and quality tested per Company's Global Practices and adhere to the latest edition of NACE RP0394, "Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating".

PHMSA

O. §195.561 When must I inspect pipe coating used for external corrosion control?

(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

EMPCo procedures for electronic inspection of coatings need to be more detailed to ensure that correct voltage settings for holiday detection are utilized for different coating types and thicknesses.

EMPCo Response
DOT Liquid Manual, added to procedure following §195.561, p. 208, underlined text:

In order to select the proper voltage setting for holiday inspection of pipeline coatings, one of the two following recommended practices should be used, dependent upon the type of pipeline coating:

1. For fusion-bonded epoxy (10 to 30 mils thickness), use the latest edition of NACE RP0490 "Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coatings (10 to 30 mils)"
2. For other types of pipeline coatings (typically much thicker than 20 mils), use the latest edition of NACE RP0274 "High-Voltage Electrical Inspection of Pipeline Coatings".

PHMSA

P. §195.569 Do I have to examine exposed portions of buried pipelines?

***Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate 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.**

EMPCo procedures need to specify that if external corrosion is found requiring corrective action, the pipe must be investigated circumferentially and longitudinally beyond the exposed portion to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

EMPCo responses for PHMSA Items P and Q follow PHMSA Item Q.

PHMSA

Q. §195.579 What must I do to mitigate internal corrosion?

(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

EMPCo procedures need to specify that if internal corrosion is found requiring corrective action, the pipe must be investigated circumferentially and longitudinally beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed portion.

EMPCo Response to PHMSA Items P and Q

DOT Liquid Manual, procedures revised and reference added to Facilities Inspection and Maintenance Management System Manual, after §195.569, p. 209. added underlined text:

PROCEDURES:

Exposed Pipe

Whenever a covered pipeline is uncovered, a Company representative at the site must thoroughly inspect the pipe. When there is evidence of corrosion, the person responsible for corrosion matters must be notified. The pipeline should then be examined circumferentially and longitudinally, on both sides of the affected area, until good pipe is visible. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate. The investigation must be documented on Form PL-751. If protection is not adequate, the technician must recommend corrective actions. Condition of the coating and the extent of external corrosion must be recorded.

For additional information on Company's corrective action, refer to document in **ExxonMobil Pipeline's** Intranet Site under **Reference Library / Manuals / FACILITIES INSPECTION AND MAINTENANCE MANAGEMENT SYSTEM (FIMMS) Manual, Corrosion Programs.**

Facilities Inspection and Maintenance Management System Manual additions/changes, Items 1, 2, and 3:

1. Atmospheric Corrosion Inspection Program, p. 7, underlined procedures added:

Other Visual Inspections
Inspections must be performed and documented on Form PL-0751 Piping Inspection & Remedial Action Report whenever buried piping is excavated during normal or unscheduled maintenance - DOT 195.569 (Liquids) and 192.459 (Gas). These inspections include, but are not limited to:
• Pipeline exposed due to third party construction
• Tie-ins made to an existing pipeline (opportunity for both external and internal visual inspections exists). Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion.-DOT 195.579(c) (Liquids) and 192.475(b)(Gas)
• Maintenance repairs made to existing pipeline (may include leak repairs, coating rehabilitation, etc.)

If external or internal corrosion is found that requires corrective action, the pipeline must be exposed both circumferentially and longitudinally beyond the exposed portion to determine the extent of the corroded area.

2. Cathodic Protection Program, p. 10, underlined text:
OVERVIEW
When any buried pipe is exposed for any reason, it shall be examined for external corrosion and documented on PL-0751. - DOT 195.569 (Liquids) and 192.459 (Gas)

If external corrosion is found that requires corrective action, the pipeline must be exposed both circumferentially and longitudinally beyond the exposed portion to determine the extent of the corroded area.

3. Internal Corrosion Control, p. 8, underlined text:
Regulatory References
DOT and other agencies require the following for jurisdictional pipelines:

• Whenever any pipe is removed from the pipeline, the internal surface shall be inspected for evidence of corrosion. If internal corrosion is found that requires corrective action, the pipeline must be investigated both circumferentially and longitudinally beyond that portion to determine the extent of the corroded area.

PHMSA

R. §195.583 What must I do to monitor atmospheric corrosion control?

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by Sec. 195.581.

EMPCo procedures need to specify repair criteria that will provide protection against corrosion and ensure that any problems discovered during inspections for atmospheric corrosion are corrected.

EMPCo Response
Revised Atmospheric Corrosion Inspection Forms, PL-750 A and B to improve process for protection and ensure corrective actions are completed when indicated. See Attachments.

PHMSA

3. §195.402 Procedural manual for operations, maintenance, and emergencies.

(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(8) In the case of pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406.

EMPCo procedures need to define fail safe as it pertains to operations of the pipeline systems.

EMPCo Response
DOT Liquid Manual, definition of "failsafe" added to "Glossary of Pipeline Terms", p. 8, underlined text:

Failsafe - Facilities that are equipped with devices that prevent over pressurization.

PHMSA

4. §195.402 Procedural manual for operations, maintenance, and emergencies.

(e) Emergencies. The manual required by paragraph (a) of this section must

include procedures for the following to provide safety when an emergency condition occurs;

(6) Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

(7) Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid.

EMPCo procedures need to include railroad traffic closure in affected areas when minimizing public exposure during hazardous liquid emergencies. Also, procedures need to reference Section 5 of the Emergency Manual for notifications to emergency and public officials.

EMPCo Response
DOT Liquid Manual, procedures revised, p. 128-129, underlined text:

PROCEDURES:

§195.402(e)(6)
Establish contact with local authorities and law enforcement agencies when appropriate. When necessary, get their assistance to inform the public, isolate the area, control traffic and/or rail, evacuate persons, and control spectators. Alert the local fire department and request that it stand by if there is any possibility that it may be needed.

§195.402(e)(7)
Procedures shall be followed as outlined in Company's Emergency Response Manual, Section 5, for establishing contact with various governmental service agencies and maintaining current communication links.

EMPCo is committed to conducting safe operations in accordance with written procedures. The foregoing procedural enhancements will contribute to our goal of continuously improving our performance.

If you have any questions or would like to discuss, please contact me at 713-656-0227 or Cathey Casey at 713-656-6913.

Sincerely,

Kevan McCrae

Attachments

PL-0750A (07-07)

ExxonMobil Pipeline Company

ATMOSPHERIC CORROSION CUI/CUF INSPECTION DETAIL

FACILITY NAME: _____ GPS - LAT: _____

COST CENTER: _____ GPS - LONG: _____

DATE: _____ GPS DATUM: _____

GPS should be expressed as degrees, minutes, & seconds

ITEM INSPECTED - DESCRIBE BELOW EACH CATEGORY THE SPECIFIC LOCATION(S) OR ID NUMBER(S) WITHIN FACILITY	NOMINAL WALL	FAULT CODE - SEE KEY BELOW	COATING/ PAINT TYPE	COATING/ PAINT CONDITION - SEE KEY BELOW	REPAIRS/REMEDIAL ACTION - INCLUDE DATE
STRAIGHT PIPE RUNS, INCLUDING PIPE RESTING ON SUPPORTS					
BRANCH CONNECTIONS, INCLUDING REINFORCEMENT PADS					
ELBOWS, REDUCERS, AND TEES					
SMALL PIPING TAKEOFFS (VALVES AND PIPING), INCLUDING GUSSETS					
IN-LINE VALVES (BLOCK, CHECK, CONTROL, ETC.)					

Distribution: Original - CIC, Copies - FIMMS Field Steward local DOT files

PL-0750A (07-07)

ExxonMobil Pipeline Company

ATMOSPHERIC CORROSION CUI/CUF INSPECTION DETAIL

FLANGES AND ASSOCIATED HARDWARE					
DEAD LEG(S)					
SCRAPER TRAP CLOSURES					
FILTER, STRAINER, ETC.					
INSULATION, WEATHERPROOFING, AND JACKETING					
PIPE SUPPORTS					
TEE SLIDES, "H" SLIDES, DUMMY LEGS, AND BASE SUPPORTS					

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PL-0750A (07-07)

ExxonMobil Pipeline Company

ATMOSPHERIC CORROSION CUI/CUF INSPECTION DETAIL

ANCHORS, RESTRAINTS, GUIDES, AND CRADLES					
SPRING HANGERS AND SUPPORT RODS, INCLUDING PIPE CLAMPS					
INSTRUMENTATION AND ASSOCIATED HARDWARE					
PRESSURE GAUGES					
THERMOWELLS AND TEMPERATURE-INDICATING INSTRUMENTS					
ORIFICE TAPS					
OTHER PRESSURE-CONTAINING INSTRUMENTS					

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PL-0750A (07-07)

ExxonMobil Pipeline Company

ATMOSPHERIC CORROSION CUI/CUF INSPECTION DETAIL

SPECIAL CONSIDERATIONS					
SOIL-TO-AIR INTERFACE (UNDERGROUND LINES AND RISERS)					
INJECTION POINTS					
SAFETY VALVE AND ASSOCIATED PIPING					
OFFSHORE SPLASH ZONES					

COMMENTS: _____

_____

_____

_____

INSPECTOR'S SIGNATURE: _____ **DATE:** _____

FIELD SUPERVISOR: _____ **DATE:** _____

AREA SUPERVISOR: _____ **DATE:** _____

☐ **PL-0751 ATTACHED**

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PL-0750A (07-07)

ExxonMobil Pipeline Company

ATMOSPHERIC CORROSION CUI/CUF INSPECTION DETAIL

KEY

FAULT CODES	CORROSION CLASSIFICATION
CGL - CORROSION - GENERAL - LIGHT	L - LIGHT - <25% WALL LOSS
CGM - CORROSION - GENERAL - MODERATE	M - MODERATE - 25% - 50% WALL LOSS
CGS - CORROSION - GENERAL - SEVERE	S - SEVERE - >50% WALL LOSS - ***NOTIFY SUPERVISOR IMMEDIATELY***
CPL - CORROSION - PITTING - LIGHT	
CPM - CORROSION - PITTING - MODERATE	***SUPERVISOR & LRMT SHOULD BE NOTIFIED WHEN CORROSION***
CPS - CORROSION - PITTING - SEVERE	***INCREASES IN SEVERITY FROM ONE CLASSIFICATION TO THE NEXT***
CUL - CORROSION UNDER INSULATION - LIGHT	
CUM - CORROSION UNDER INSULATION - MODERATE	
CUS - CORROSION UNDER INSULATION - SEVERE	
CFL - CORROSION UNDER FIREPROOFING - LIGHT	
CFM - CORROSION UNDER FIREPROOFING - MODERATE	
CFS - CORROSION UNDER FIREPROOFING - SEVERE	
NCD - NO CORROSION DETECTED	
DA - DAMAGED/BROKEN	
ER - ERODED/WORN	
FO - FOULED/DEPOSITS PRESENT	
IF - INSULATION FAILURE	
LK - LEAKING - ***NOTIFY SUPERVISOR IMMEDIATELY***	
LS - LOOSE	
MI - MISSING	
NI - NOT INSPECTED	

	PAINT/COATING CLASSIFICATION
CE - COATING - EXCELLENT	E - EXCELLENT - <1% DISBONDMENT, VERY MINOR TO NON-EXISTENT HOLIDAYS
CG - COATING - GOOD	G - GOOD - 1% - 10% DISBONDMENT, SCATTERED HOLIDAYS
CF - COATING - FAIR	F - FAIR - 10% - 50% DISBONDMENT, SCATTERED TO NUMEROUS HOLIDAYS
CP - COATING - POOR	P - POOR - 50% - 100% DISBONDMENT, NUMEROUS HOLIDAYS WITH CORROSION DEPOSITS OR ELECTROLYTE BENEATH
PE - PAINT - EXCELLENT	
PG - PAINT - GOOD	
PF - PAINT - FAIR	
PP - PAINT - POOR	
B - BARE	

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

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 29, 2007

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, Texas 77002

CPF 4-2007-5032M

Dear Mr. Pruessing:

On April 2-6, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, conducted an inspection of ExxonMobil Pipeline Company's (ExxonMobil) operations and maintenance procedures in Houston, Texas. As a result of the inspection, ExxonMobil was issued a Notice of Amendment on August 23, 2007. This Notice proposed amendment of your procedures to assure safe operation of your pipeline facility.

ExxonMobil submitted its amended procedures on October 22, 2007. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Montana DOT Pipeline Audit
July 27-30, 2009

Visual Corrective Actions

Fromburg Dump Span Before Clearing



Fromburg Dump Span After Clearing.
Completed 8-14-09



Clarks Fork River Before Clearing.



Clarks Fork River After Clearing.
Completed 8-19-09



Clarks Fork River After Clearing.
Completed 8-19-09



Valve 1061 Before Work



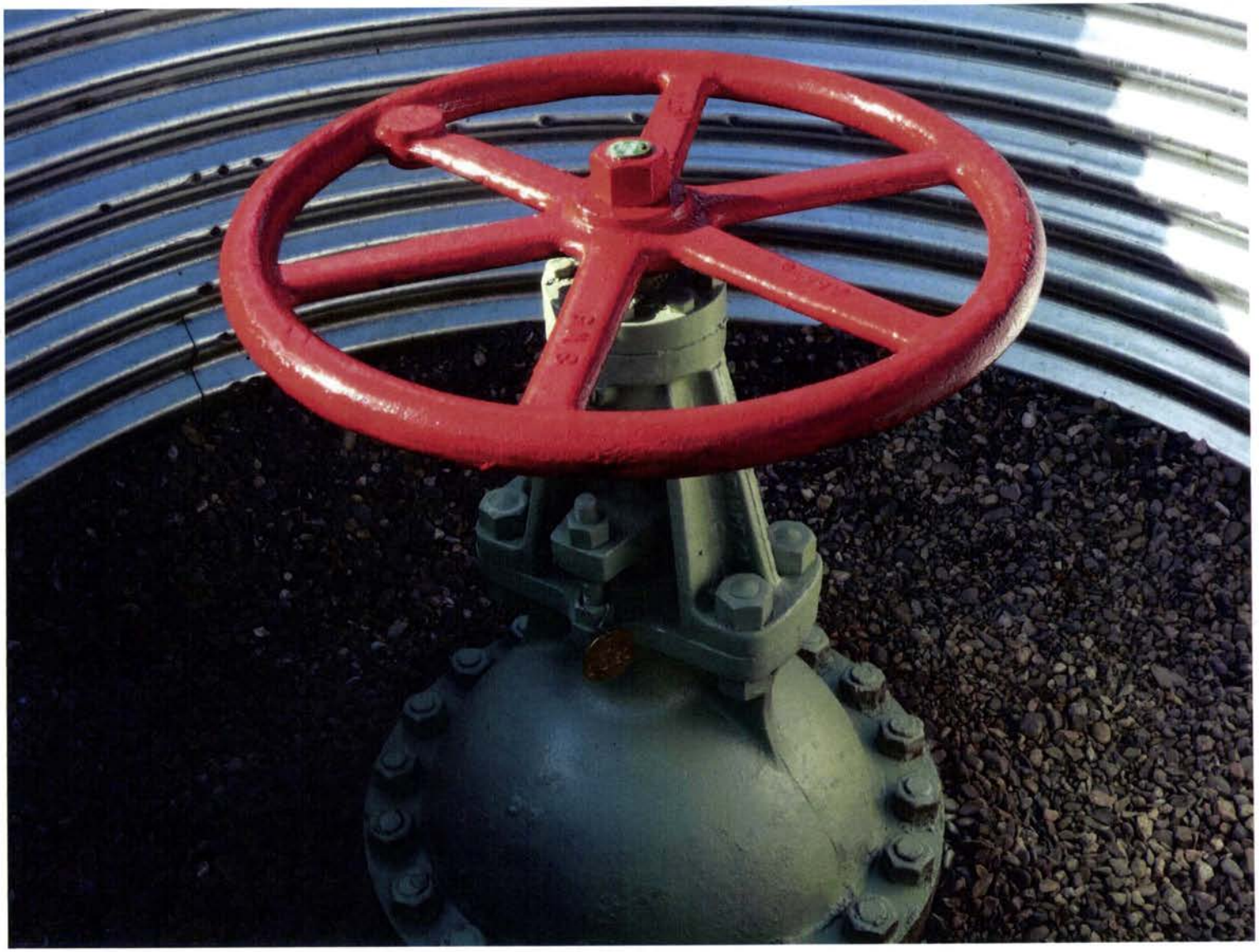
Valve 1061 After Work.
Completed 8-17-09



Valve 1061 Before Work



Valve 1061 After Work.
Completed 8-17-09



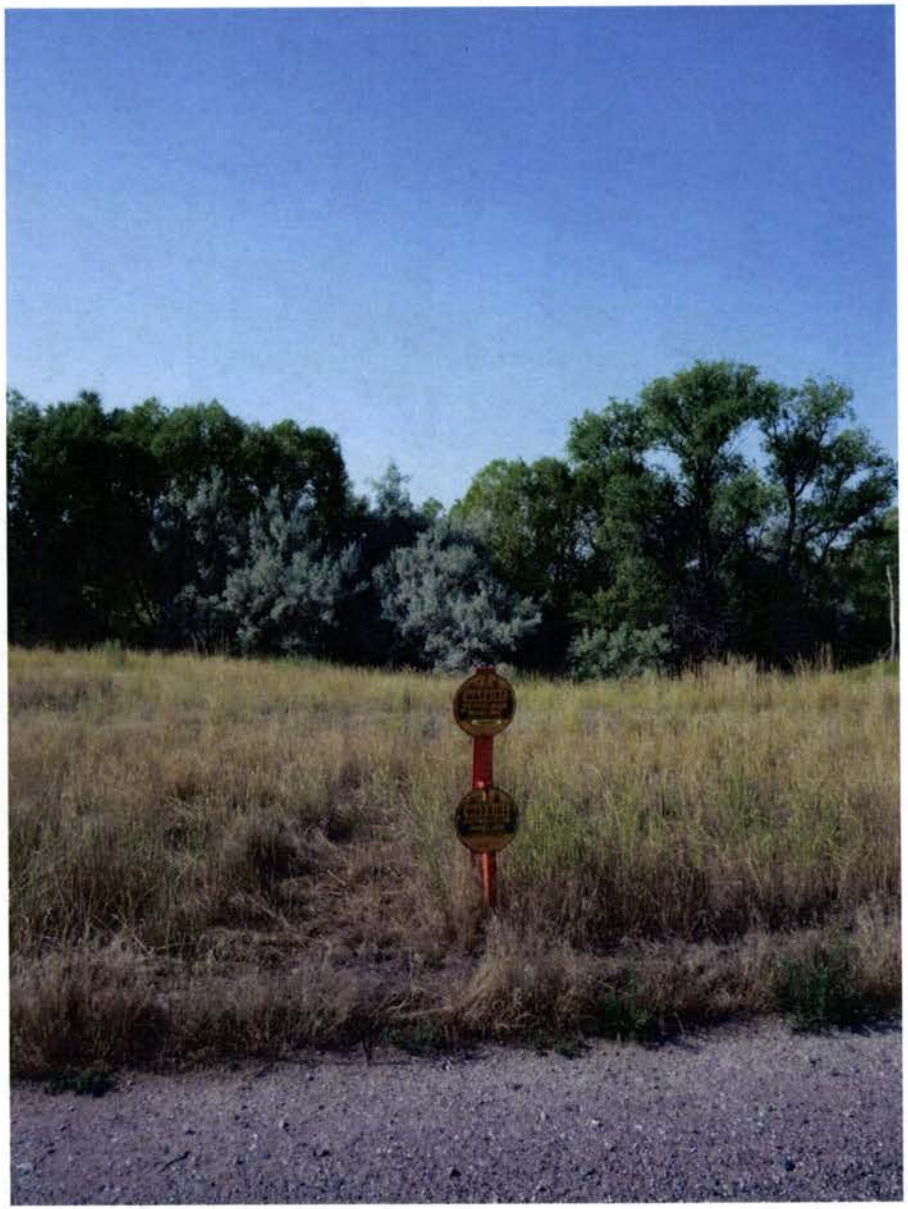
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Valve 1060 After Work.
Completed 8-17-09



MP 51.991 Before Work



MP 51.991 Before Work



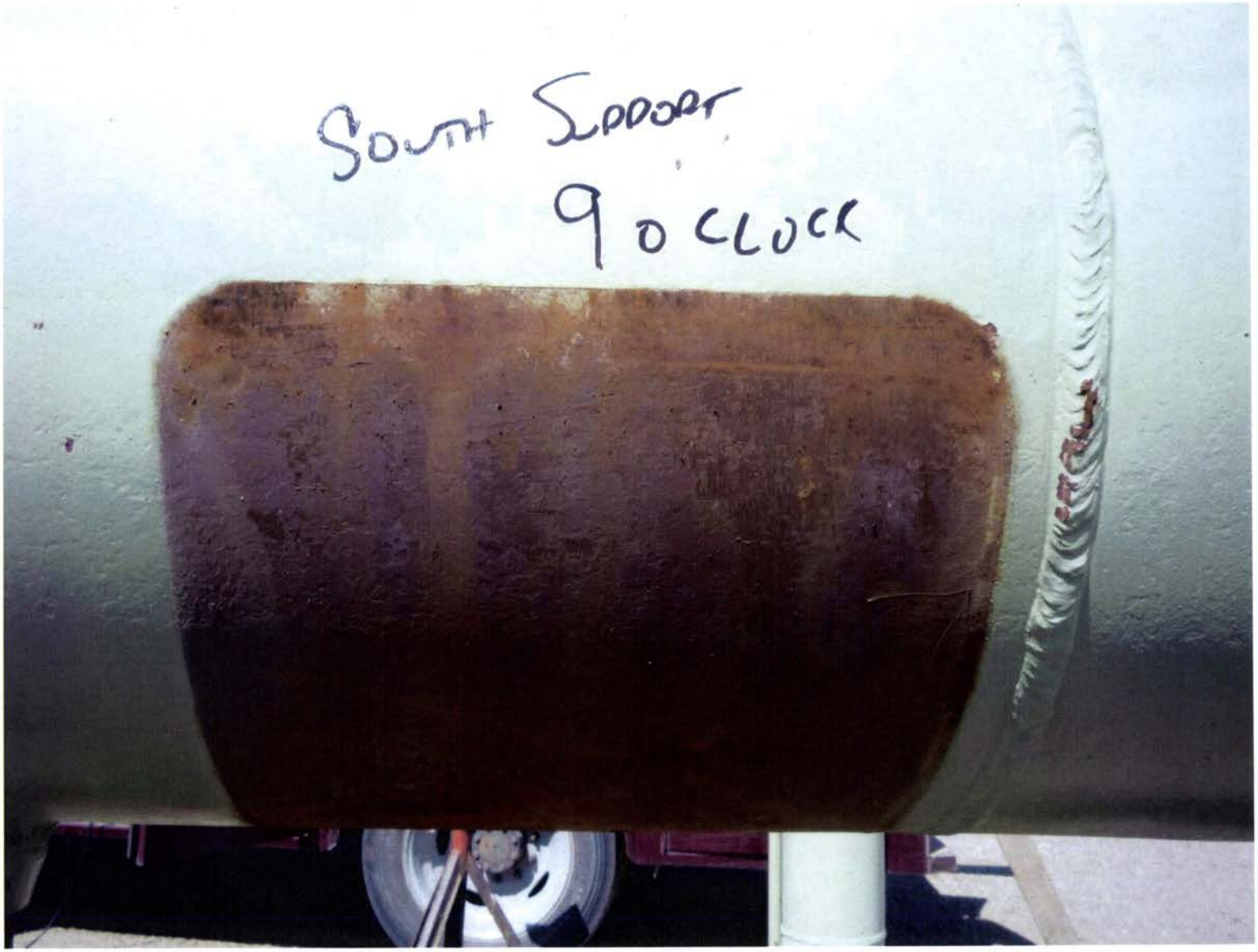
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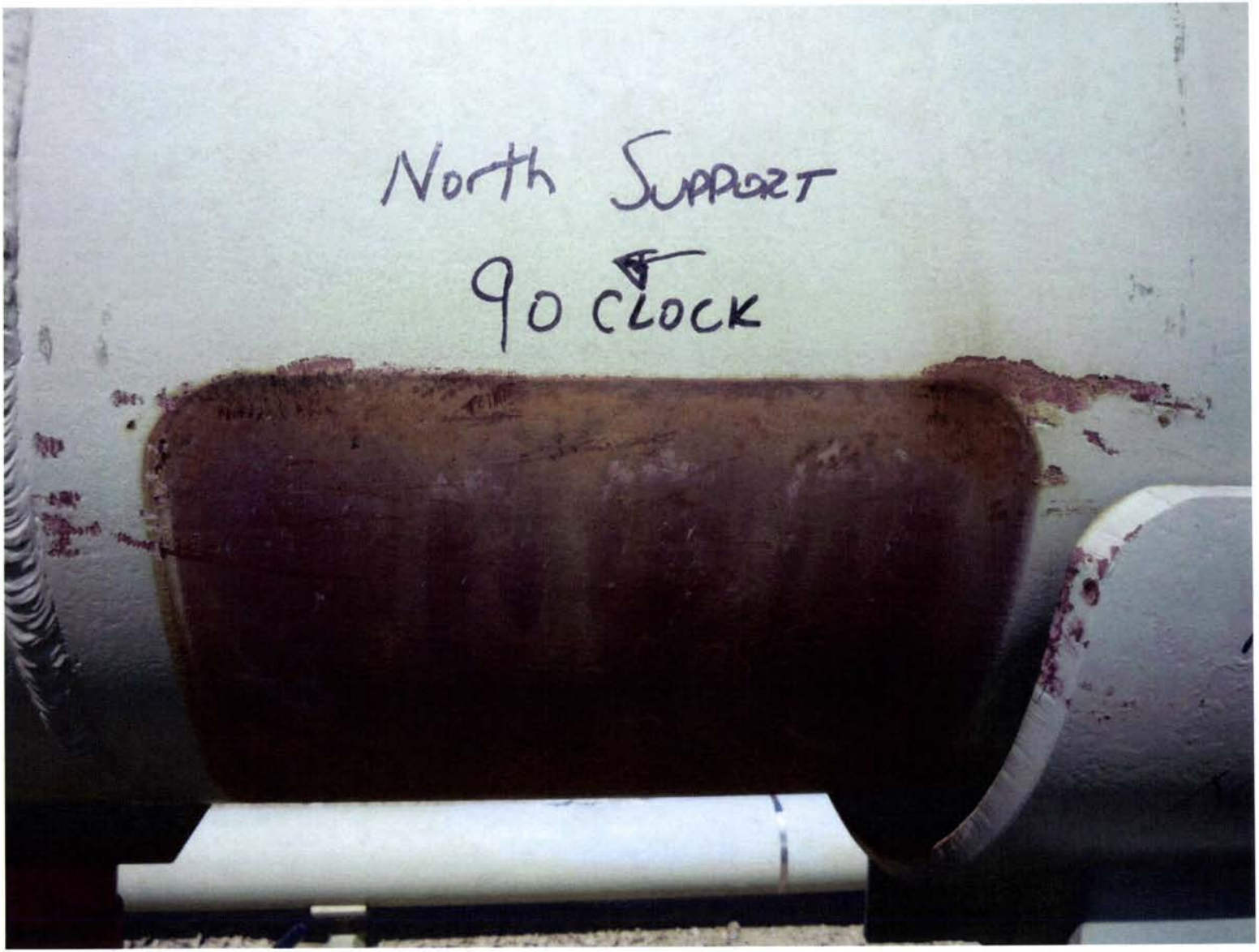
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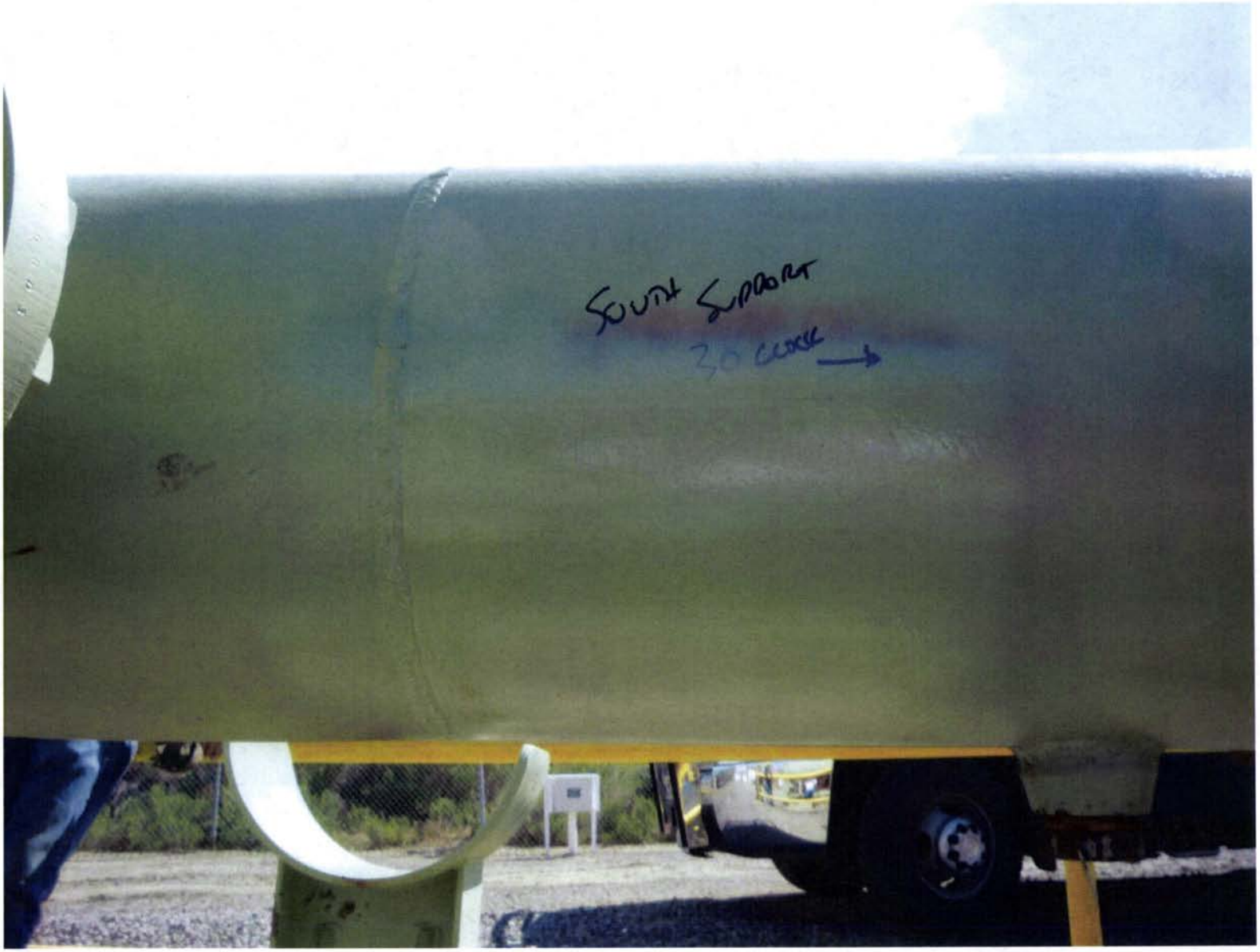
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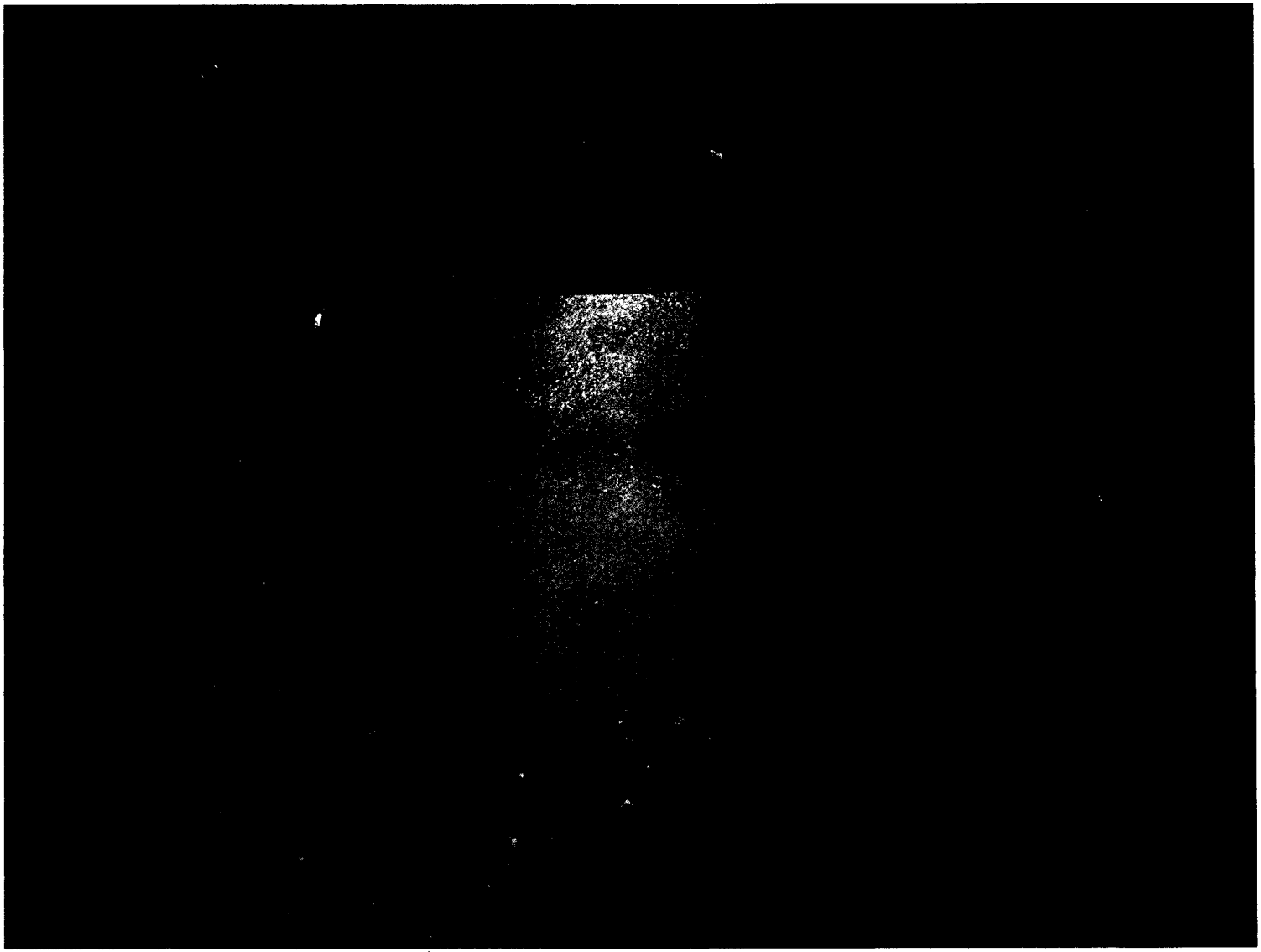
Silvertip Scraper Trap Before Work



Silvertip Scraper Trap After Work.
Completed 8-18-09



Silvertip Scraper Trap After Work.
Completed 8-18-09



Silvertip Scraper Trap After Work.
Completed 8-18-09



End of Slide Show

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 5, 2008

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, Texas 77002

CPF 4-2007-5044M

Dear Mr. Pruessing:

On August 28-29, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, conducted an inspection of ExxonMobil Pipeline Company's (ExxonMobil) operator qualification plan procedures in Houston, Texas. As a result of the inspection, ExxonMobil was issued a Notice of Amendment on November 30, 2007. This Notice proposed amendment of your procedures to assure safe operation of your pipeline facility.

ExxonMobil submitted its amended procedures on January 7, 2008. My staff reviewed the amended procedures, and it appears that the inadequacies outlined in this Notice of Amendment have been corrected.

This letter is to inform you no further action is necessary and this case is now closed. Thank you for your cooperation.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 27, 2007

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company
800 Bell Street, Room 741D
Houston, Texas 77002

CPF 4-2007-5044M

Dear Mr. Pruessing:

On August 28-29, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected ExxonMobil Pipeline Company's (ExxonMobil) Operator Qualification Plan in Houston, Texas.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within ExxonMobil's plans or procedures, as described below:

1. **§195.505 Qualification program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   (b) Ensure through evaluation that individuals performing covered tasks are qualified;

ExxonMobil's OQ plan needs requirements to:

- Ensure effective communication of operator-specific requirements for task performance when qualified contractor individuals speak and comprehend languages other than English.
- Ensure evaluation methods used to qualify individuals to perform certain covered tasks that may require more physical effort should include a performance verification to ensure that the individual has the ability to perform the covered task.

- Address procedures for mergers and acquisitions.

2. **§195.505 Qualification program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   (c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

ExxonMobil's OQ plan needs requirements to ensure the ability of qualified individuals to effectively communicate direction of task activities and reactions to AOCs to non-qualified individuals who speak and comprehend languages other than English.

3. **§195.505 Qualification program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   (f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

ExxonMobil's OQ plan needs requirements to utilize incident investigations, employee feedback programs, or other approaches to ensure that the AOCs identified and used in evaluating individuals are representative of those that could reasonably be anticipated during performance of covered tasks.

4. **§195.505 Qualification program.**

   Each operator shall have and follow a written qualification program. The program shall include provisions to:

   (i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

ExxonMobil's OQ Plan needs requirements to address what will be considered as a significant modification required to notify PHMSA and/or appropriate state agencies.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 4-2007-5044M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

ExxonMobil Pipeline Company
800 Bell Street – (PL-EMB-603B)
Houston, Texas 77002
713 656 0227 Telephone
713 656 8232 Facsimile

K. G. (Kevan) McCrae
Manager
Safety, Health And Environment Department

ExxonMobil
Pipeline

Sent via Certified Mail

January 7, 2007

Mr. R. M. Seeley, Director
Southwest Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
8701 South Gessner, Suite 1110
Houston, TX 77074

Re: Notice of Amendment Resolution
CPF 4-2007-5044M

Dear Mr. Seeley:

ExxonMobil Pipeline Company (Operator ID 4906) received a Notice of Amendment (NOA), CPF 4-2007-5044M, on November 30, 2007 in response to a headquarter inspection of our Operator Qualification Program conducted by two representatives of the Pipeline and Hazardous Materials Safety Administration on August 28 and 29, 2007. ExxonMobil Pipeline Company (EMPCo) has addressed the amendments noted in the NOA and is submitting this correspondence as per the Procedures for Responding to a Notice of Amendment included with the NOA.

The amendments listed in the NOA have been addressed and incorporated into EMPCo's Operator Qualification (OQ) Written Program. A description of each specific response and revision to EMPCo's OQ Written Program is summarized on the following two pages. An electronic copy of this letter, the enclosed summary, and EMPCo's amended OQ Written Program are also provided on the enclosed compact disk.

These amendments were addressed during the EMPCo OQ Administrator's annual review of our OQ Written Program that was completed in October 2007 and became effective November 1, 2007. These amendments were regarded as being within the context of a significant change according to 49 CFR 195.505(i). Pursuant to compliance with this regulation, EMPCo submitted notification to PHMSA and applicable state agencies on November 19, 2007.

EMPCo is fully committed to maintaining an effective OQ Program and satisfying the requirements of PHMSA and applicable state agencies. Our responses to the NOA are believed to satisfy the requirements of 49 CFR 195, Subpart G, Qualification of Pipeline Personnel. If you have any questions concerning our response or would like additional information, please contact Paul Merritt, ExxonMobil Pipeline Company OQ Advisor, at (713) 656-3777 or paul.h.merritt@exxonmobil.com.

Sincerely,

Kevan G. McCrae
Manager
Safety, Health and Environment Department

Enclosures: Notice of Amendment Resolution
EMPCo OQ Written Program (electronic format on compact disk)

Amendment 1

Regulator Reference: 195.505(b), Ensure thorough evaluation that individuals performing covered tasks are qualified.

Description: ExxonMobil's OQ Program needs requirements to:

- Ensure effective communication of operator-specific requirements for task performance when qualified contractor individuals speak and comprehend languages other than English.
  - EMPCo Response:
    The addition of this stipulation to EMPCo's OQ Program is consistent with bilingual requirements that exist separately within EMPCo's Contractor Safety Program which requires bilingual safety supervision at all times when non-English speaking contract employees are performing work. The stipulation requiring a contractor to provide bilingual communication for non-English speaking contract employees was added to Section 7.9, Contractors Roles and Responsibilities (page 31).
- Ensure evaluation methods used to qualify individuals to perform certain covered tasks that may require more physical effort should include a performance verification to ensure that the individual has the ability to perform the covered task.
  - EMPCo Response:
    Further description addressing the performance evaluation of physical abilities necessary to complete a covered task was added to Section 5.0, Evaluations (page 19) and Section 5.4.3, Performance-Based Evaluations (page 24). The physical abilities to be considered during a performance evaluation now refer to "visual, oral, hearing, and other physical requirements" on page 19.
- Address procedures for mergers and acquisitions.
  - EMPCo Response:
    Provisions for integrating employees, assets, and contractors through mergers and acquisitions were added to Section 5.0, Evaluations (page 20) and Section 7.3, OQ Advisor Roles and Responsibilities (page 30). A determination of the compatibility of individuals and assets to be incorporated in EMPCo's OQ Written Program through merger or acquisition has been added to the OQ Advisor's responsibilities.

Amendment 2

Regulatory Reference: 195.505(c), Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified.

Description: ExxonMobil's OQ Program needs requirements to ensure the ability of qualified individuals to effectively communicate direction of task activities and reactions to abnormal operating conditions (AOCs) to non-qualified individuals who speak and comprehend languages other than English.

- EMPCo Response:
  The stipulation for bilingual communication between the qualified person providing span of control and the non-qualified individuals was added to Section 4.4, Span of Control Over Non-Qualified Individuals (page 17) and Section 5.2, Non-Qualified Individuals and Span of Control (page 22).

Amendment 3

Regulatory Reference: 195.505(f), Communicate changes that affect covered tasks to individuals performing those covered tasks.

Description: ExxonMobil's OQ Program needs requirements to utilize incident investigations, employee feedback programs, or other approaches to ensure that the AOCs identified and used in evaluating indi-

viduals are representative of those that could reasonably be anticipated during performance of the covered task.

- EMPCo Response:
  Section 10.2 (page 37) was re-titled "Program Feedback and Assessments" to specifically include "feedback." Further description of methods used to communicate and obtain feedback on program changes, including those affecting AOCs, was added. EMPCo's incident investigation process is also utilized to ascertain whether an individual's performance, which would include his or her inability to properly recognize and react to an AOC, may have contributed to an accident. This is addressed in Section 4.3, Re-qualification, on page 16.

Amendment 4

Regulatory Reference: 195.505(i): After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

Description: ExxonMobil's OQ Program needs requirements to address what will be considered as a significant modification required to notify PHMSA and/or appropriate state agencies.

- EMPCo Response:
  The definition of a "significant change" to the OQ Program was added to Section 8.0, Program Maintenance and Communicating Changes (page 34). Text providing the definition of a "significant change" was added to the existing paragraph on page 34 to indicate that EMPCo will notify PHMSA and applicable state agencies concerning significant changes. The added definition utilizes the same language found in the PHMSA OQ Inspection Form 14, Revision 5, Protocol 8.02.

ExxonMobil Pipeline Company

Qualification of Pipeline Personnel

Operator Qualification Written Program

October 2007

ExxonMobil Use Only

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Revision Log

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10/2007	PHM	Further detail was added to Section 4.3, Re-Qualification (pages 16 and 17), concerning the criteria and actions for re-evaluating/re-qualifying an individual whose actions may have been a causal factor in an incident. The stipulation for bilingual communication between the qualified person providing span of control and the non-qualified individuals was added to Section 4.4, Span of Control Over Non-Qualified Individuals (page 17), Section 5.2, Non-Qualified Individuals and Span of Control (page 22), and Section 7.9, Contractors Roles and Responsibilities (page 31). Further description addressing the performance evaluation of physical abilities necessary to complete a covered task was added to Section 5.0, Evaluations (page 19) and Section 5.4.3, Performance-Based Evaluations (page 24). Provisions for integrating employees, assets, and contractors through mergers and acquisitions were added to Section 5.0, Evaluations (page 20) and Section 7.3, OQ Advisor Roles and Responsibilities (page 30). The reference to "task(s)" was changed to "task" in Section 5.2 (page 21) to indicate that a qualified individual may observe up to five non-qualified individuals performing a single covered task, not multiple tasks simultaneously. The definition of a "significant change" to the OQ Program was added to Section 8.0, Program Maintenance and Communicating Changes (page 34). Section 10.2 (page 37) was re-titled "Program Feedback and Assessments" and further description of methods used to communicate and obtain feedback on program changes, including those affecting AOCs, was added. The information in former Section 10.3, Assessing Evaluation Methods Result, was included in Section 10.2. Former Section 10.4, Additional ISNetworld Requirements, renumbered 10.3. A column titled "Span of Control" was added to the Covered Task List in Appendix 1 to identify the number of non-qualified individuals that can be observed by a qualified individual under span of control for each covered task.
3/2007	PHM	The EMPCo OQ Guidance Document was incorporated into the EMPCo OQ Written Program.
	3/23/2007 addendum	Task 3, Repairing Breakout Storage Tanks, was replaced with specific existing covered tasks applicable to breakout tank maintenance and repairs: Task 27, Coating or Recoating Pipe, Task 37, Welding or Repair to Welds on Existing Lines, and Task 38, Performing Non-Destructive Tests. The Task 3 Covered Task Analysis (page 59) and reference to Task 3 in the list of Covered Tasks in Appendix 2 (page 55), were removed. Task 3 was also removed from the Covered Task List in Appendix 1 (page 41).

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Revision Date	Revised By	Revision Description
		API 1104 and ASME Boiler and Pressure Vessel Code, Section IX, welder certifications were added to the Method of Evaluations for Task 37, Welding or Repair to Welds on Existing Lines (page 92), as specific industry-accepted Welding Qualification Programs (page 19), and as accepted Welding Qualifications (page 25). The re-qualification frequency for the API and ASME certification was limited to six months for consistency with DOT regulations. The re-qualification frequency on the Covered Task Analysis for Task 38, Performing Non-Destructive Tests (page 93), was revised from 1 year to 3 years for consistency with API 1104 (as indicated on the Covered Task Analysis), ASME B31Q, Qualification of Pipeline Personnel, and with the current frequency tracked in the ISNetworld database. Section 4.1.3, Maintaining Accurate Assigned Qualifications, was revised for consistency with the current process for maintaining employee qualifications (page 14). "Removed from service" revised to "removed from pipeline facility" in Section 6.0, Field Application of OQ, to further clarify that only tasks performed on regulated equipment removed from facility is outside the scope of OQ requirements (page 27). The paragraph in Section 6.0, Field Application of OQ, explaining the purpose of the OQ Covered Task Record (PL-2421) was reworded to recognize non-qualified individuals performing covered tasks under the span of control of a qualified individual (page 27). Reference to "construction" in the OQ Covered Task Record paragraph in Section 6.0 was removed as OQ applies only to operations and maintenance tasks (page 27).
10/2006	PHM	The position of Contractor Safety Advisor was added to the Foreword (third paragraph, page vii). The list of joint venture entities was updated to include T & M Terminal Company (page 2). Two categories of Abnormal Operating Conditions were added for consistency with ASME B31Q Standard: a) Interruption or Failure of Communications, Control System or Power and b) Inadequate Odorization or Reports of Gas Odor (subsections 2.6.9 and 2.9.10, page 8). Additional descriptions were added to AOCs in subsections 2.6.2, 2.6.3, 2.6.4, and 2.6.8 (pages 7 and 8) to establish correlation with B31Q Standard AOCs. Reference to the "OQ Covered Task Record (PL-2421)" replaced reference to "checklist" (page 12). A copy of the OQ Covered Task Record was added to Appendix 3. Covered Task Analyses in Appendix 2 were revised to include the two additional Abnormal Operating Condition categories. A Task Description was added to Task 32, Clock Spring Pipeline Repairs, to distinguish between the installation of composite sleeves limited to the Clock Spring process and the installation of composite sleeves covered by Task 41, Repairing/Replacing Pipelines (Appendix

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Revision Date	Revised By	Revision Description
		2). Reference to "Clock Spring" was replaced with "composite" in the Task Description of Task 41, Repairing/Replacing Pipelines. "Installation of composite sleeves according to Clock Spring process, Task 32" was added to the list of Task Exclusions (Appendix 2).
7/2006	PHM	Covered Task Analysis for Task 3, Repairing Breakout Storage Tanks (Appendix 2, page 35), was updated to a) recognize NCCER Modules 62307-02, Tank Repair, and 66102, Abnormal Operating Conditions, as acceptable OQ evaluation methods, and b) identify work on geodesic roofs as being exempt from the scope of OQ. A new Covered Task Analysis identifying Work on Geodesic Dome Roof as a non-OQ covered task was added to Appendix 2, page 120. Appendix 1, OQ Covered Task List, page 30, was updated to include Work on Geodesic Dome Roof as a non-OQ covered task. List of EMPCo Contacts in Foreword, page vi, was updated to identify current Training Supervisor.
10/2005	PHM	Annual review of the Written Program and the Guidance Document was completed. The EMPCo Contacts table in the Written Program Foreword was updated. Este CO_2 Pipeline System and Slaughter CO_2 Pipeline System removed from list of entities owned by Exxon Mobil Corporation in Section 1.0. Covered Task List in Appendix 1 was updated to include Task 10, Odorization, and the Covered Task Analysis for Task 10 was added to Appendix 2. Reference to "Work Process Documentation Form" replaced with "OQ Covered Task Record" in Guidance Document, Section 7.0. References to the evaluation methods listed on Covered Task Analyses were updated as necessary for consistency with revisions concerning external (third party) evaluation methods.
12/2004	PHM	Title of Task 31 changed to Routine Monthly Inspection of Breakout Storage Tanks, and Task 35 changed to Inspecting In-Service Breakout Storage Tanks. Changes provide titles consistent with API covered tasks for breakout storage tank inspections. Flow Rate Deviation was added to the definitions of Abnormal Operating Conditions (Section 2.6.8). Reference to Subsea Connections in Section 4.2 was changed to Underwater Activities as covered tasks that cannot be performed under Span of Control. Foreword added.
11/2004	PHM	Underwater Covered Tasks 51 - 65 were added and replaced Task 34, Subsea Connections. Task 34 had been under development and not formally implemented.

Revision Date	Revised By	Revision Description
		Covered Task Analyses reformatted for clarity; field added to identify required prerequisite tasks; US Distribution job titles added to list of personnel eligible to complete the tasks.
10/2004	PHM	Annual review of Written Program completed. The sections on Communicating Changes (formerly Section 4.5) and Plan Maintenance (formerly Section 6.0) were combined as Section 5.0, Program Maintenance and Communicating Changes, to eliminate redundancy.
09/2004	PHM	References to disconnection of pipeline equipment or components from a regulated pipeline facility as a means to exempt covered task requirements were removed.
07/2004	PHM/COC	EMPCo and US Distribution Written Programs reviewed and consolidated. The Introduction (Section 1.0) was reviewed by Law and revised for clarity.
04/08/2003	MMS	Reformatted document. Added regulatory references. Removed ISNetworld exceptions.
03/11/2003	MMS	Clarified that contractors are required to bring an electronic printed copy of their qualifications to company job-sites. Clarified the process to administer written evaluations orally. Identified things that should be considered before an individual is requalified. Added the process of documenting contractor's qualification on the checklist attached to the JSA.
02/07/2003	MMS	Clarified tasks that could not be performed by non-qualified individuals (see Non-Qualified Individuals section).
01/20/2003	MMS	Added the offshore tasks that are covered and not covered.
10/24/2002	ARF/MMS	Added OQ for All (MEA) Qualification Methods to each covered task analysis. Modified the specific AOCs for each covered task.
10/15/2002	MMS	Included passing grade on each internal evaluation method. Provided a copy of the "Program Acceptance" form. The form is used to review third party programs to determine if they are acceptable to the Company. Added form to the Table of Contents.
10/11/2002	ARF	Added acceptable Qualification Methods to each covered task analysis.
10/11/2002	MMS	Clearly defined physically connected to include springing a blind. Added an exception to ISNetworld for contractors that perform a limited number of OQ tasks at one work location. Added the Plan Maintenance section on how the plan is maintained.
09/06/2002	MMS	Added paragraph that contractors will be trained on AOCs at an Annual Orientation Training. Added two more acceptable OQ programs (EM Distribution, EM Production West).
09/05/2002	MMS	Removed the paragraph on affiliate requirements and replaced it with a more accurate paragraph. Revised the Abnormal Operating Condition

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Revision Date	Revised By	Revision Description
		(AOC) definitions. Modified the AOC on the Covered Task Analysis sheets to match the revised definition. Removed Monthly Tank Inspections from Task 35 and made Task 31 Monthly Tank Inspections a stand-alone task. Removed Clockspring repair method from Task 41 and created Task 32, Clockspring Repairs. Added an exclusion to Task 33 which excludes 3rd party line crossings as a covered task. Added rationale as to why 3rd party line crossings are not a covered task. Added additional evaluation methods that are acceptable.
07/16/2002	MMS	Revised the Covered Task Analysis to more clearly define tasks.
07/05/2002	MMS	Added Acceptable Evaluation Programs to the Table of Contents. Added the word "disconnected" to the Removed from the System Definition. Added language on how we ensure employees and contractors qualifications are current/valid. Added the list of evaluation methods that are acceptable.
06/03/2002	MMS	Added the process on how the plan will be maintained and items which could result in a change to a covered task, added in-line inspection task.
05/22/2002	MMS	Inserted sentence in Affected Personnel section that pointed individuals to the Operator Qualification Guidance document for additional guidance on implementing OQ. Removed "work performance history" as an evaluation method. Removed the paragraph that explains when work performance history can be used and how to document work history. Modified the sentence on work history to read that work history may not be used as the sole evaluation method at any time. Added a sentence explaining that after an alternate qualification method is accepted, any individual meeting the requirements of the alternate method and has documentation to substantiate the qualification will be deemed qualified. Corrected the Task Rating to align the frequency with the intended frequency on the covered task list. Modified the Contract and Third Party personnel paragraph to read that a contract must utilize NCCER or an approved third party and that they may not utilize their own program. Added a sentence to read that affiliates may qualify under our program or NCCER's. If affiliates choose not to utilize our evaluation methods they must comply with the requirements of our program. Added ISNetworld to Communicating Change paragraph. Removed reference stating work history performance history will be retained in OID. Added requirement for contractors to use ISNetworld.
03/04/2002	ARF	Moved "Log of Revisions" behind "Table of Contents." Inserted "hereafter referred to as" wording in the Introduction. Changed to considering work performance history on a case-by-case basis for contractors and third parties.
02/20/2002	ARF	Added timeframe for review of plan for its effectiveness and reason for communicating changes to plan.
02/08/2002	ARF	Included reference to 49 CFR 191 and 192 where appropriate. Deleted "oral exam" as an acceptable evaluation method. Stipulated that qualifying by work history is not acceptable for 3rd parties & contractors. Clarified parameters for performance based qualification

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Revision Date	Revised By	Revision Description
		method. Expanded consideration to, "any incident", rather than just DOT reportable, for evaluation of performance history for transitional qualification. Revised references to "the Company."
10/02/2001	MMS	Removed reference to contractors qualifying under the Company's program, defined the number of non-qualified individuals that one qualified individual can direct, added accepted industry certification programs or equivalent to evaluation methods, added the methods that written and performance qualification methods would be administered.
05/21/2001	MMS	Identified effective date, added log of revisions, identified date all employees need to be qualified, clarified work performance history documentation and where document will be retained.

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Foreword

Administration of the Qualification of Pipeline Personnel Program is conducted in accordance with the requirements and responsibilities identified in this document, also referred to as the OQ Written Program.

ExxonMobil Pipeline Company's OQ Written Program is used in conjunction with other Company manuals, such as the ExxonMobil Pipeline Company (EMPCo) DOT Liquids and Gas Manuals, the Safety Manual, the Terminal Operator Guide, and the Policy and Procedures Manual. Together, these tools provide personnel with the skills and knowledge needed to safely operate and maintain the Company's pipeline facilities/systems.

ExxonMobil Pipeline Company's Safety, Health and Environment Department is responsible for maintaining the OQ Program. The responsibilities of the OQ Advisor, Contractor Safety Advisor and Training Advisor outlined in Sections 7.3, 7.4,and 7.5, respectively, are managed by the following individuals:

EMPCo Contact	Title	Area of Responsibility	Telephone Number
Paul Merritt	Safety Compliance and Qualification Advisor	EMPCo Employees	(713) 656-3777
Tommy Jackson	Contractor Safety Advisor	Contractors	(713) 656-3807
Jan Bowman	Training Supervisor	EMPCo Training	(713) 656-4159

EMPCo's OQ Program was first implemented on April 27, 2001. The current version was last revised in October 2007 and became effective November 1, 2007.

The location of text revisions to the current version that are listed in the Revision Log are identified with a vertical bar in the left margin.

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1.0 Introduction

ExxonMobil Pipeline Company, hereafter referred to as "the Company" or "EMPCo," has developed an Operator Qualification (OQ) Program to accomplish the following:

- Ensure a qualified workforce.
- Reduce the probability and consequence of accidents caused by human error.
- Comply with the requirements in 49 CFR Part 195, Subpart G Sections 195.501 through 195.509 and/or 49 CFR Part 192, Subpart N Sections 192.801 through 192.809.

The Company's OQ Program applies to all covered assets that are owned and operated by the Company. Additionally, the Company's program serves as the OQ Program for other ExxonMobil entities that are wholly owned and operated by ExxonMobil affiliates for which the Company provides certain services pursuant to service agreements. The Company's program does not serve as the OQ Program for those entities for which the Company provides contract services and which are not wholly owned by an ExxonMobil affiliate.

The following relates the ExxonMobil affiliate structure to 49 CFR Part 195 - Subpart G Sections 195.501 through 195.509 and/or 49 CFR Part 192, Subpart N Sections 192.801 through 192.809.

Exxon Mobil Corporation wholly owns a number of affiliates. The Company provides services pursuant to contract service agreements for various heritage Exxon or Mobil affiliates who own and/or operate pipeline systems. The pipeline systems subject to 49 CFR Part 195 and/or 192 for these operators and/or owners are included in the Company's OQ Program.

Note: The list below does not contain all of the entities that are subject to 49 CFR Part 195 or 192 that are owned by Exxon Mobil Corporation.

This list is inclusive of two types of entities:

- The Company either wholly owns or operates. Currently ExxonMobil Pipeline Company is the only wholly owned or operated affiliate.
- Entities the Company has a contract service agreement with but is neither the owner nor the operator.

Operator ID Number	Operator Name
4906	ExxonMobil Pipeline Company [1]
12624	Mobil Corporation
26134	ExxonMobil Oil Corporation [2]
32009	ExxonMobil Oil Corporation - Terminals
12628	Mobil Pipe Line Company
30005	Mobil Pacific Pipeline Company
12634	Mobil Chemical Company
25160	Mobil Vanderbuilt-Beaumont Pipeline Co
Note: [1] Renamed, Formerly Exxon Pipeline Company [2] Renamed, Formerly Mobil Oil Corporation	

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The following relates the ExxonMobil joint venture structure to 49 CFR Part 195 and/or Part 192, Qualification of Pipeline Personnel.

Exxon Mobil Corporation, or one of its subsidiaries, is a shareholder, member or partner in a number of joint venture entities in which there are other shareholders, members or partners. The Company may provide certain contract services for some of these entities pursuant to service agreements; however, the Company is neither the owner nor the operator of the pipeline systems nor is the Company a shareholder, member or partner in these entities.

The pipeline systems that are subject to 49 CFR Part 195 or 192 for these operators and/or owners are not included in the Company's OQ Program. These entities have their own OQ programs. The Company may have served as a contractor and developed an OQ Program for the entity, but each joint venture entity, as the owner and operator of the assets, is responsible for the implementation of its own OQ Program.

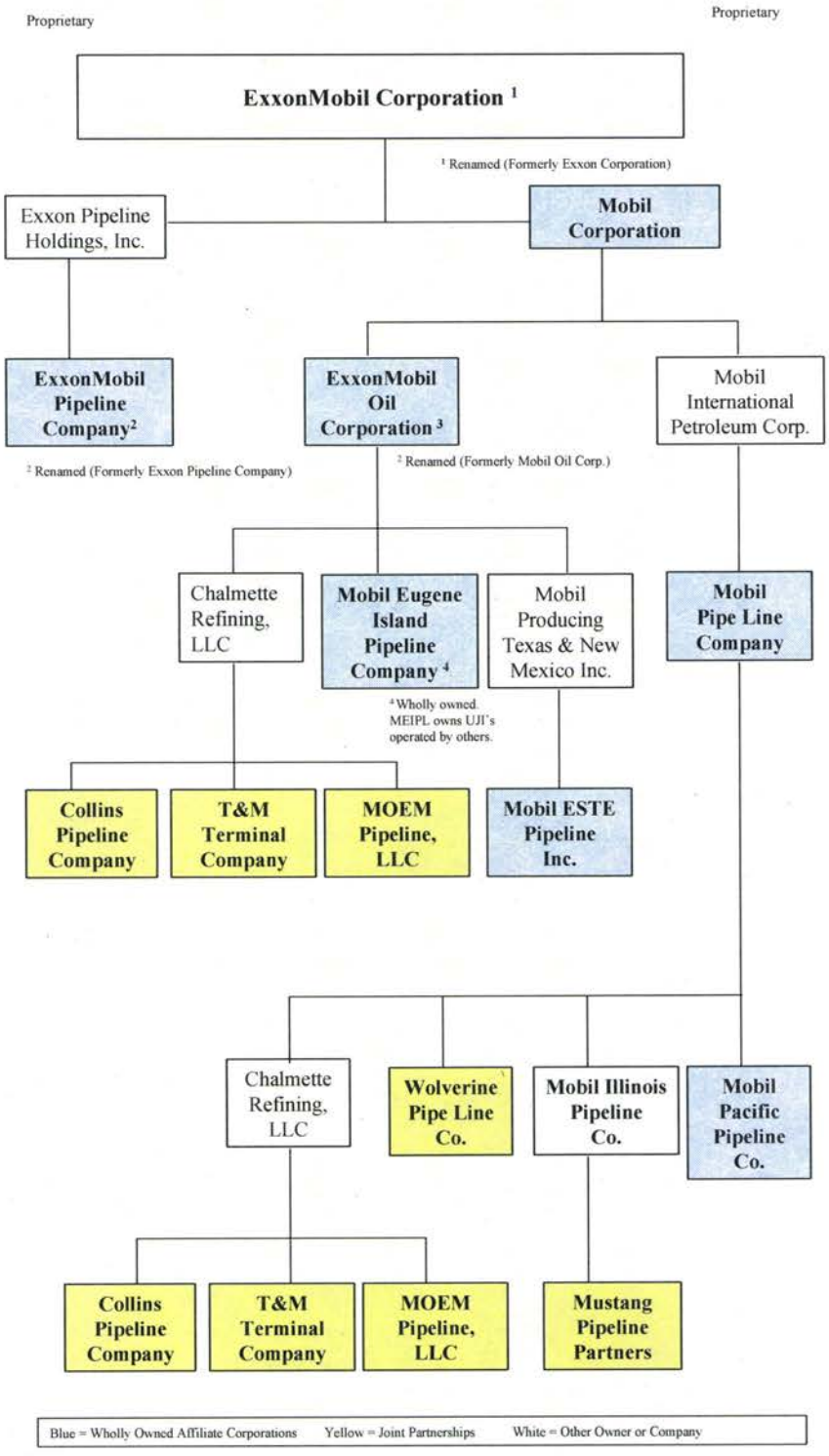
Note: This list is not inclusive of all entities that are subject to 49 CFR Part 195 or 192 that Exxon Mobil Corporation or one of its affiliates has a percent ownership in.

Operator ID Number	Operator Name
2546	Collins Pipeline Company
31167	MOEM Pipeline, LLC
31166	Mustang Pipeline Partners
19481	T & M Terminal Company
22830	Wolverine Pipe Line Company

See the Affiliate Structure and Joint Partnership Structure Diagram on the next page.

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Affiliate and Joint Venture Structure



The program addresses the following required elements (49 CFR Part 195.505 or 192.805):

1) Identify covered tasks that personnel perform on our pipeline facilities.
2) Ensure, through evaluation, that individuals are qualified to perform covered tasks.
3) Identify the process in which non-qualified individuals may perform a covered task under the direct observation of a qualified person.
4) Evaluate an individual if there is reason to believe that the individual's performance of a covered task contributed to an accident, as defined in 49 CFR Part 195, or an incident, as defined in 49 CFR Part 191.
5) Evaluate an individual if there is reason to believe that the individual is no longer qualified to perform a covered task.
6) Ensure that changes affecting covered tasks are appropriately communicated.
7) Identify the intervals at which re-evaluation of the individual's qualifications is needed.

The Company chartered an internal team consisting of operations, maintenance, engineering, DOT advisors, and support staff to determine the operations and maintenance tasks that individuals must be qualified to perform. The team applied the four-part test as specified in the Qualification of Pipeline Personnel rule to all of the operations and maintenance tasks contained in DOT Part 195 and 192. The four-part test consists of the following questions (49 CFR Part 195.501 or 192.801):

- Is the task performed on the pipeline?
- Is the task an Operations or Maintenance Task?
- Is the task required by DOT Part 195 or 192?
- Does the task affect the operation or integrity of the pipeline?

All four questions must be answered "yes" for the activity to be a covered task.

Operations and maintenance tasks required by Part 195 or 192, but fail the four-part test, are not covered tasks. The Company's rationale as to why these tasks do not meet the four-part test is documented on the Covered Task Analysis. Appendix 2 contains the Covered Task Analysis for each covered and non-covered task.

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2.0 Premises and Definitions

The following premises and definitions were developed to ensure accurate and consistent analysis of operation and maintenance activities. Key words were defined to provide a standard for interpretation. Premises address how the four-part test was applied to identify covered tasks and explain the Company's understanding of abnormal operating conditions associated with covered tasks.

2.1 Covered Task

A covered task satisfies the following criteria:

- Is an activity performed by an individual or group of individuals
- Has a beginning and an ending point
- Has two or more steps
- Can be observed and measured
- Has been identified by the Company
- Meets all four of the conditions discussed below:

1) **Performed on a pipeline facility** means an activity that is performed by an individual or group of individuals whose performance directly impacts a regulated pipeline system.
   a) **Pipeline facility** refers to new and existing pipe, rights-of-way, and any equipment, facility, or building used in the transportation of hazardous liquid, carbon dioxide, or natural gas.
   b) **Activity** means physical, visual, or mental effort directed at achieving a result.
   c) **Removed from the system** means that a part of an existing pipeline facility has been physically removed from the pipeline system to an offsite vendor facility.
   d) **Pipeline system** means all parts of a DOT regulated pipeline facility through which a hazardous liquid moves in transportation (line pipe, valves, appurtenances, pumps, meters, tanks, etc).
2) **Operations and maintenance tasks** are activities done by an individual or group of individuals (1) to perform a function on a pipeline facility or (2) to provide upkeep of a pipeline facility.
   a) A "new construction task" changes to an operations and maintenance task when the DOT pipeline system is being commissioned (the act of commissioning is a covered task).
   b) The following are not operations and maintenance tasks:
      i) Activities on new or existing pipelines that have never been in service or commissioned.
      ii) Fabrication of new installations.
      iii) Emergency response activities not involving operations and maintenance activities.
      iv) Calculations, studies, reporting conditions.
3) **Required by Part 195 or 192** means only those tasks specifically required or interpreted to be required in Part 195 or 192. State and local requirements are not applicable to this rule.
4) **Affects the operation or integrity of the pipeline** means any activity that could directly or indirectly cause the release of hazardous liquid to the environment or result in a hazard to persons or property.
   a) Pipeline means Pipeline System as defined in 1 d) above.
   b) An affect can be either immediate (direct) or delayed (indirect).
   c) The integrity of the pipeline refers to the pipeline's ability to operate safely and to withstand stresses imposed during operations.

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Rationale for Non-Covered Tasks

a) A rationale has been provided for tasks that are not considered "covered," under EMPCo's OQ Program. Tasks that are not covered include tasks that did not satisfy the four-part test. The rationale provides an explanation as to why EMPCo did not consider the task as a covered task and is consistent with the **Premises and Definitions** identified in the OQ Program.

b) The rationale will provide consistency and insight during regulatory and internal reviews of the OQ Program.

The lists of EMPCo Covered Tasks and Non-Covered Tasks are provided in Appendix 1.

2.2 Evaluation

Evaluation means a process, established and documented by the Company, to determine an individual's ability to perform a covered task.

2.3 Qualified

Qualified means the following:

- An individual has passed an evaluation
- The individual can perform assigned covered tasks
- The individual can recognize and react to abnormal operating conditions
- The compliance documentation is completed

2.4 Individual

Individual means a person who, on behalf of the Company, performs one or more covered tasks on a pipeline facility operated by the Company.

2.5 Operate

- Operate means starting, stopping, monitoring, controlling, and running equipment.
- Must/Shall mean mandatory.
- Should/May means practices which are preferred, but for which the operator may determine that alternate practices are equally or more effective.

2.6 Abnormal Operating Condition

Abnormal Operating Condition (AOC) means a condition identified by the Company that may indicate a malfunction of a component or deviation from normal operations that may:

- Indicate a condition exceeding design limits
- Result in a hazard(s) to persons, property, or the environment

Note: A deviation from normal operation does not necessarily mean an abnormal operating condition exists. Refer to Figure 1: Abnormal Operating Condition Decision Flow Chart.

The ten categories of Abnormal Operating Conditions are as follows:

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2.6.1 Explosion or fire not intentionally set by the Company

2.6.2 Unexpected Hazardous Liquids Encountered

Unexpected hazardous liquid encountered refers to the discovery of an unplanned escape of product from a pipeline.

2.6.3 Component Failure

Component is defined as any part of a pipeline, which may be subjected to pump pressure including but not limited to pipe, valves, elbows, tees, flanges, and closures. Component failure may result in an unplanned pressure deviation, e.g. increase, decrease, high, low, absent. Examples of component failure are as follows:

- Failure of a valve
- Stopple failure
- Launcher closure door
- Pipe failure
- Relief valve failure
- Flange gasket failure
- Weld/seam failure
- Mechanical sleeve failure (i.e. Plidco bolt on, Weld+end)
- Tubing failure

2.6.4 Abnormal Facility Condition (AFC)

Abnormal Facility Condition (AFC) is a condition that could have an immediate impact to the operation of the pipeline system. Examples are as follows:

- Washed out pipe along a stream or river bank
- Exposed piping in a water crossing
- Flooding that is or would affected the stability of the pipeline
- Soil movement such as landslide, mudslide, or sinkholes found during the performance of the covered task.
- Damaged or failing pipe support system
- Sagging aboveground pipe at a span

2.6.5 Physical System Damage

Physical System Damage is any damage to the pipeline or its components that has not yet failed but will impair the continued safe operations or use of a pipeline or component.

Listed below are some examples of physical system damage:

- Gouge
- Dent
- Cracks
- Damage to an external/internal floating roof tank
- Wrinkle bend

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- External impact to valve or actuator or other component
- Damage because of natural causes (i.e. wind, flooding, hurricane, earthquake, snow, ice, subsidence, etc)
- Shell damage to a tank

2.6.6 Unexplained Status Change

Unexplained Status Change is a change that could impact the ability of the pipeline to operate safely. Examples are unexplained pump unit starting/stopping and unexplained valve status changes.

2.6.7 Activation of a Safety Device

Activation of a Safety Device refers to devices that prevent overpressure or overfill conditions and prevent systems from exceeding design limits, such as MOP, High-High Tank Level, tank or vessel design pressure.

2.6.8 Flow Rate Deviation

Flow Rate Deviation refers to an unexplained or unplanned change in the rate of liquids/product movement through the pipeline, i.e. high flow, low flow, no flow. The consequence of a Flow Rate Deviation could impact the safe operation of the pipeline.

2.6.9 Interruption or Failure of Communications, Control System or Power

Interruption or failure of communications, control system, or power refers to the loss of capability to effectively monitor, operate or control the pipeline system. Examples include:

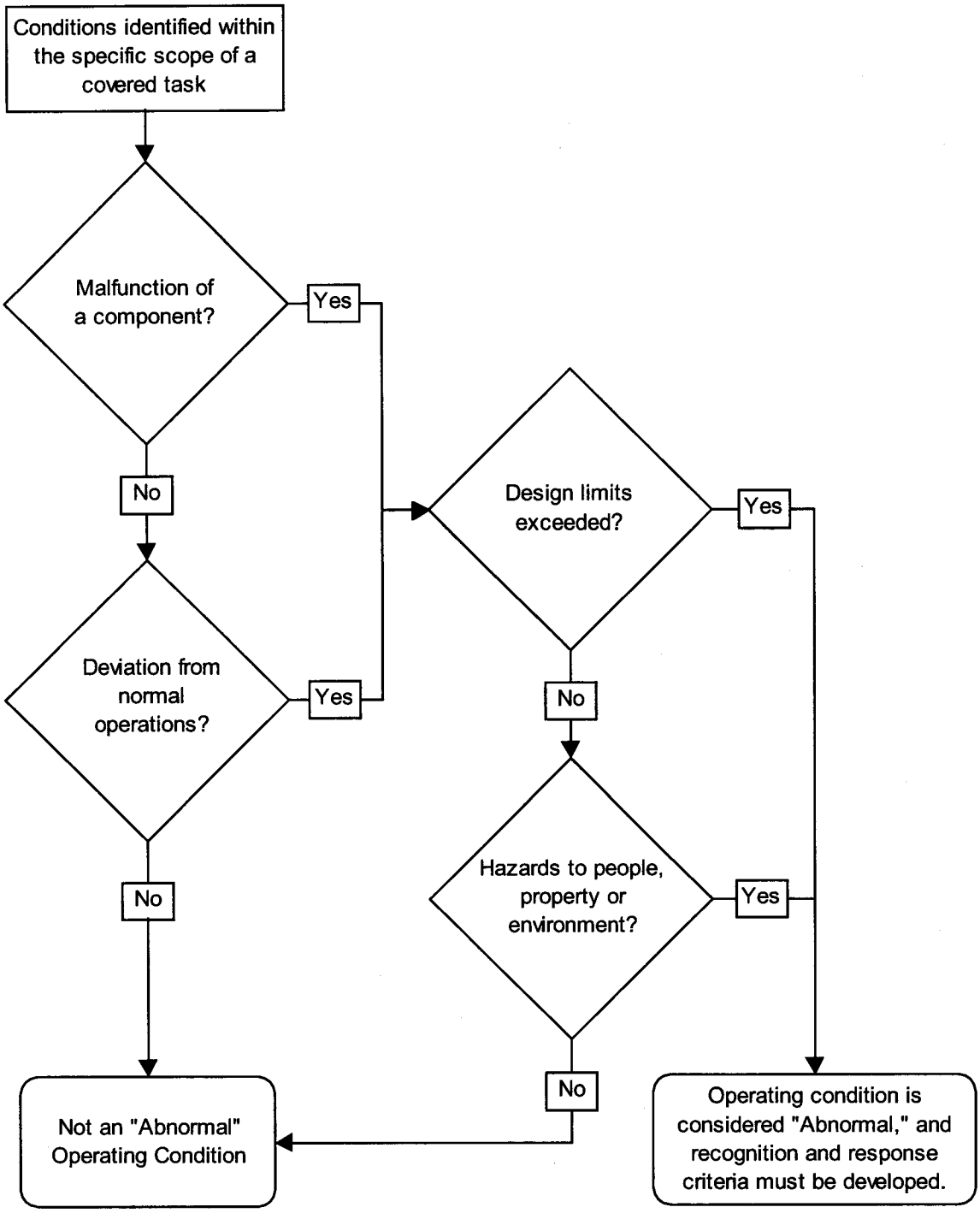
- Loss of supervisory control and data acquisition system communication
- Loss of operation control center power supply system
- Loss of pump station power supply
- Loss of communication to remote control motor operated valve
- Loss of communication to remote control pump

2.6.10 Inadequate Odorization or Reports of Gas Odor

Inadequate odorization refers to lack of odorant in natural gas transported through the pipeline system. The report of gas odor pertains to the detection of odor emanating from the pipeline and notification to the pipeline operator of the odor.

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Figure 1: Abnormal Operating Condition Decision Flowchart



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3.0 Covered Tasks

3.1 Covered Task Analysis

A covered task analysis was completed for each covered task performed at EMPCo. The covered task analysis specifies what is included or not included in the task. The analysis also identifies job types within the Company that may need to be qualified in this task. Job types were identified to ensure job skills were grouped appropriately. The covered task analysis also identified how the four-part test was applied, the re-evaluation frequencies, the acceptable evaluation methods, and the abnormal operating conditions that could be present.

Each Covered Task Analysis is provided in Appendix 2 of the OQ Written Program.

3.2 Non-Covered Task Analysis

A rationale was developed for tasks that are not considered "covered," under the Company's OQ Written Program. Tasks that do not meet all parts of the four-part test are not covered. The rationale provides an explanation why a task is not considered to be a covered task and ensure consistency with the premises and definitions identified in the OQ Written Program. Refer to Appendix 2 to review the non-covered task analyses.

The rationale also provides consistency and insight during regulatory and internal reviews of the OQ Written Program.

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4.0 Qualification Process

4.1 Company Qualification Process

4.1.1 Employee – Initial Qualification Process

Note: An initial qualification is required when an employee was not performing covered tasks before October 26, 1999.

Before a new employee is permitted to perform OQ tasks, he/she must first pass a probationary period that is utilized to assess his/her ability and demonstrate the skills expected of the job. Employees are not permitted to perform covered tasks during this probationary period unless being directed/observed by a qualified individual or after satisfactorily passing the evaluation method. The applicable portions of the Company's Operations Integrity Management System (OIMS) 5A, Personnel and Training Addendum, must be met before employees are given an opportunity to qualify in covered tasks.

When an individual is hired, a profile is established in EMPCo's electronic training platform. The individual is assigned courses that meet company and regulatory requirements. As an individual progresses through his/her probationary period, or during the annual verification process, his/her Supervisor will provide the Local OQ Administrator with a list of covered tasks that the employee will be expected to perform after his/her initial training/orientation is complete.

The employee will receive the training (formal and on-the-job) necessary to acquire the knowledge and skills to become proficient in his/her job assignment. As knowledge and skills are acquired, the individual may take the assigned written exams or performance-based exams to become qualified in covered tasks. Work history is not an acceptable evaluation method.

Written tests are administered by the Company's computer-based training platform. The test results will be documented automatically in Mockingbird. The Local OQ Administrator will enter performance test results into Mockingbird.

Each employee may run a report in Mockingbird to determine what task(s) he/she is qualified in and/or what task(s) an employee may need to be re-qualified in.

EMPCo's employee selection and placement process and training requirements are documented in OIMS System 5A.

4.1.2 Employee – Transitional Qualification Process

A transitional qualification is a qualification that was completed prior to October 28, 2002 for employees who had been performing a covered task on a regular basis prior to October 26, 1999.

Prior to October 28, 2002, Field Supervisors provided a list of the operations and maintenance tasks each of their direct reports could be expected to perform after October 28, 2002. Field supervisors identified the tasks and submitted that information to SHE. SHE entered the information into the computer-based training platform. Therefore, each individual was assigned covered tasks based on his/her current job expectations.

Employees were required to complete their assigned evaluation methods prior to October 28, 2002 in order to perform that covered task. Work history was not an acceptable evaluation method.

Written tests are administered by the Company's computer-based training platform. The test results will be documented automatically in Mockingbird. The Local OQ Administrator will enter performance test results into Mockingbird.

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Each employee may run a report in Mockingbird to determine what task(s) he/she is qualified in and/or what task(s) an employee may need to be re-qualified in.

4.1.3 Maintaining Accurate Assigned Qualifications

Annually, Supervisors are requested to review employees' curriculums as listed in the Mockingbird computer-based training platform and to process any changes through the Local OQ Administrator. Any changes to an employee's OQ task list should be updated at this time. Changes to an employee's OQ task list could occur due to an employee performing different roles for the Company.

Supervisors are also responsible for notifying the Local OQ Administrator when an employee's role changes such that the employee would need to become qualified to perform a task for which he/she is currently not qualified. The Local OQ Administrator will assign the OQ task to the employee's curriculum prior to his/her performing the task.

4.1.4 Employee – Subsequent Qualification Process

Subsequent qualification refers to re-evaluating an individual at an interval established by the Company.

A frequency for re-qualification has been identified for each covered task. Before the frequency specified for each task is reached, the individual must be re-qualified. If the qualification lapses, the individual may not perform that covered task until re-qualified or unless the task is permitted to be performed under the direction/observation of a qualified individual.

The computer-based training platform will inform an individual three months prior to his/her qualification expiring. The employee must successfully pass the evaluation method identified for that task(s) before the due date lapses.

Written tests are administered by the Company's computer-based training platform. The test results will be documented automatically in Mockingbird. The Local OQ Administrator will enter performance test results into Mockingbird.

The multifunctional OQ team determined the re-qualification frequency for each covered task. The team considered two factors in determining the re-qualification frequency: criticality and complexity. Each task was assigned two ratings: one for criticality and one for complexity. The ratings ranged from 1 - 3, a rating of 1 indicated a low level of criticality or complexity, and 3 indicated the highest level of criticality and complexity (Frequency of task performance was not a variable in determining re-qualification frequencies).

Based on the two ratings, a re-qualification frequency of 1 year, 3 years, or 5 years was assigned. For more information on the re-qualification frequencies for each covered task, refer to the Written Program or covered task list.

4.2 Contractor Qualification Process

In addition to the Company's OQ requirements, contract companies must comply with the requirements set forth in the Company's contract or service order. This includes adopting standards that are equal to or more stringent than the Company's.

Contract personnel must be qualified prior to performing any covered tasks unless a qualified person is directing and observing the non-qualified individuals. The qualified person may be an operator's employee, an operator's representative (third-party inspector), or a contractor representative.

Contractor personnel must be qualified to perform covered tasks through a program that is identified as acceptable to the Company. Acceptable evaluation methods are identified in our Written Program. A

form entitled Acceptance Process for Evaluation Methods is completed to document the Company's review of any external evaluation method. The results of the review are documented in the Written Program.

If a contractor qualifies their personnel under a program that is not listed in EMPCo's Written Program, the program must be approved by the Company and available for the Company to perform periodic audits before individuals will be allowed to perform covered tasks. Contractors may not use work performance history as the sole evaluation method at any time.

When the Company's affiliates are providing services to the Company under a service agreement, they must meet the requirements of this Program.

Any contract company that performs an OQ task for EMPCo must also have a Drug and Alcohol program that meets DOT requirements. Refer to EMPCo's Contractor Selection Process.

Contractors are required to post OQ records on ISNetworld before any individual will be permitted to perform a covered task unless that individual is working at the direction of a qualified individual. Contractors are also required to bring a printed copy of their qualifications to the EMPCo job-site. In addition, EMPCo will perform periodic checks of contractors' OQ records during contractor headquarter audits, site safety assessments, or randomly performed spot checks.

4.2.1 Contractor Compliance – Transitional

Note: Transitional refers to contractors that were performing a covered task on a regular basis prior to October 26, 1999.

To ensure EMPCo's contractor workforce was qualified by October 28, 2002, the following steps were taken:

1) **Phone survey** - In January 2001, EMPCo conducted a phone survey. Twenty-five DOT designated contractors were contacted to understand if contractors were familiar with the OQ requirements. The findings of the phone survey indicated that 50% of the companies contacted were developing plans to comply with OQ.
2) **Contractor Workshop** - Over the course of 2001, EMPCo conducted several contractor workshops throughout the states in which we operate. Contractors were provided with a review of EMPCo's requirements and contact information where they could get more information.
3) **Contractor Letter** - In January 2002, every contract company listed on EMPCo's approved contract list was sent a letter explaining EMPCo's OQ requirements, a questionnaire, a copy of our covered task list, and Written Program. Contractors were asked to complete the questionnaire, which identified if they were impacted by the rule and how they intended to meet EMPCo's requirements. EMPCo documented the results of the questionnaires submitted. Contractors that did not reply were contacted by phone. This contractor interface is documented in the contractor OQ files.
4) **Contractor Workshops** - Over the course of 2002, EMPCo conducted several contractor workshops throughout the states in which we operate. Contractors were provided with a review of EMPCo's requirements and contact information to help them comply.
5) **Contractor Letter** - In July 2002, every contract company listed on EMPCo's approved contract list was sent a letter updating the contract company on EMPCo's OQ requirements. Contractors that were meeting our requirements were identified as OQ compliant on our approved contractor list. Contractors that were not meeting our requirements were placed on the restricted list until they met our requirements.

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4.2.2 Contractor Compliance – Initial

Each contractor is assessed before they are added to the preferred contractor list. The assessment ensures that the contractor meets EMPCo's safety and drug and alcohol requirements and also ensures the contractor satisfies EMPCo's OQ requirements. As part of this assessment, the new OQ contractor will receive an OQ package. The package identifies EMPCo's OQ requirements and OQ contact information. Before the contractor is added to the preferred contractor list, they must meet all of EMPCo's OQ requirements. Each contractor's compliance status is documented in the Company's on-line preferred contract list. For complete details on this process, refer to the Contractor Safety and Administration Manual.

4.2.3 Contractor Compliance – Subsequent

Subsequent qualification refers to re-evaluating an individual at an interval established by the Company.

A frequency for re-qualification has been identified for each covered task. Before the frequency specified for each task is reached, the individual must be re-qualified. If the qualification lapses, the individual may not perform that covered task until re-qualified or unless the task is performed at the direction/observation of a qualified individual.

ISNetworld identifies the date in which an individual must be re-qualified.

4.3 Re-qualification

EMPCo's Written Program identifies the circumstances in which individuals need to be re-qualified. Personnel will be re-evaluated and re-qualified prior to performing the covered task when any of the following circumstances occur (49 CFR 195.505 or 192.805):

1) **Re-qualification Frequency:** A frequency for re-qualification has been identified for each covered task. Before the frequency specified for each task is reached, the individual must be re-qualified. If the qualification lapses, the individual may not perform that covered task until re-qualified or unless task is performed under the direction and observation of a qualified individual.
2) **Reason to believe performance contributed to an accident:** After an incident occurs, it is the Field Level Supervisor's or Area Supervisor's responsibility to determine if an individual's performance of a covered task contributed to the incident. If it is determined that the individual's performance did contribute to the incident, the individual must be re-qualified prior to further performance of the covered task. If it is determined that the individual's performance did not contribute to the incident, the individual does not need to be re-qualified.
3) **Reason to believe an employee is no longer able to perform or displays unsatisfactory performance:** If an individual's performance is identified to be unsatisfactory, regardless of whether it has resulted in an incident, the individual must be re-qualified prior to further performance of the covered task. An individual's performance may be determined to be unsatisfactory during an incident investigation, observations by Supervisors or other qualified individuals, or a near-miss occurrence.
4) **Significant changes to equipment, procedures or location:** Supervisors and employees need to be aware of difference between facilities and locations. Employees may be qualified to perform a covered task at one location, but because of the facility/unit differences, the employee may not be able to perform that covered task at all locations. Qualified individuals and the local supervision should discuss if there are any concerns.
5) **Individual requests re-qualification:** If individuals have a current qualification but feel they need to be re-qualified prior to completing a covered task, the individual should repeat the qualification or should notify his/her Supervisor to repeat the qualification method.

Before attempting to re-qualify an employee, the Supervisor should consider and document any of the following that are completed:

- Reviewing the applicable policy and procedure(s) with the individual
- Assigning a qualified individual to work with the individual
- Identifying applicable training for the individual

When it is determined that a contractor needs to be re-qualified, the Company Contractor Safety Advisor will suspend the individual's qualification(s) in ISNetworld, an electronic web-based database. Furthermore, the local Supervisor will ensure the contractor has been re-qualified before returning to any Company job site. If the individual's record(s) are not in ISNetworld because an exception has been granted, the Company Contractor Safety Advisor will notify the individual and the local supervisor to verify the individual has been re-qualified prior to returning to any Company job site.

When an incident is reported to SHE as required in the Incident Notification and Reporting Guide, the SHE representative receiving the notification will collect the available information. The Incident Notification Process Flowchart in Attachment B of the reporting guide is provided to ensure proper notifications are completed. Consideration is given as to whether an individual must be re-qualified along with other post incident requirements.

Root cause analyses and corrective actions identified during an incident investigation are documented in the IMPACT database.

4.4 Span of Control Over Non-Qualified Individuals

Non-qualified individuals may complete certain covered tasks only when being directed by a qualified individual. The qualified individual must limit the number of non-qualified individuals to ensure he/she can take immediate corrective action in the event an abnormal operating condition occurs.

A qualified person can effectively observe multiple non-qualified individuals performing covered tasks in a close proximity area. However, each qualified individual may not observe more than five non-qualified individuals performing those tasks that allow observations under the span of control of a qualified individual. Five covered tasks cannot be performed by a non-qualified individual (refer to Section 5.5.2).

There can be no obstructions between the non-qualified individuals and the qualified person that would impede the qualified person's ability to directly observe and take immediate corrective action.

The qualified person providing the span of control must be able to effectively communicate verbally with the non-qualified individuals. Bilingual communication **must** be provided and available at all times when non-English-speaking personnel are performing the covered task.

4.4.1 Examples of Span of Control

- Breakout storage tanks

  It is not acceptable for non-qualified individuals to be working on top of the tank or inside of the tank if the qualified individual is not directly overseeing the work.

- Recoating job

  It is not acceptable to have non-qualified individuals working at various places along a section of pipe with one qualified individual directing the work. He/She will not be able to ensure appropriate actions.

- Purging/Flaring an HVL line

  The qualified individual will want to determine the appropriate number of non-qualified individuals that he/she can adequately observe. This is especially true when performing a complex task such as purging and flaring lines.

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- Qualified persons cannot direct non-qualified individuals from a vehicle.

Considerations for determining span of control:

- Size of Work Area
- Complexity of Task
- Size of Work Group
- Barriers in the Work Area
- Experience of Work Group

4.4.2 Span of Control Restrictions

There are certain tasks, because of the nature of the task, which a non-qualified individual may not perform even at the direction of a qualified individual. A qualified individual must perform the tasks listed below:

- Clock Spring repairs
- Underwater Activities
- Welding/Welding Repairs
- Performing NDT testing
- Excavating Activities

Any individual that cannot pass the specified evaluation method(s) for a covered task will not be permitted to perform that covered task, except under the direction/observation of a qualified person. If appropriate/necessary, additional training may be provided to develop the necessary skills and knowledge needed to perform the task before the individual will be permitted to attempt to pass the evaluation method(s).

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5.0 Evaluation Methods

Each individual is evaluated in each covered task that he/she will be expected to perform to ensure that he/she is qualified to perform the tasks. The Company's employee selection and training processes in addition to the evaluation methods ensure the individual possesses the knowledge and skills necessary to perform all the activities identified on the covered task analysis that apply at his/her work location. The evaluation also ensures the individual is able to recognize and react to any abnormal operating conditions that may arise while completing the task.

The applicable portions of the Company's Operations Integrity Management System (OIMS) 5A, Personnel and Training Addendum, must be met before employees are given an opportunity to qualify in covered tasks.

The following evaluation methods or a combination of methods, as applicable, will be used:

- Written exam
- Observation during performance on-the-job
- Observation during on-the-job training
- Simulations
- Accepted industry certification programs or equivalent (NACE, American Society for Non-Destructive Testing (ASNT), Welding Qualification Programs API 1104 and ASME Boiler and Pressure Vessel Code, Section IX, etc.).

Written qualification methods are used to evaluate Company employees' knowledge and skills and are usually administered by computer. Performance-based qualification provides an evaluation of an individual's skills demonstrated to properly complete the covered task. Performance-based evaluations include the Loss Prevention System (LPS) Loss Prevention Observation (LPO) and/or Job Safety Analysis (JSA). These LPS tools will be administered by individuals that have been trained in the observation process to:

- Understand the written checklists that must be used while conducting a performance based test.
- Compare the individual's performance to the required performance criteria identified on the written performance-based checklists.
- Substantiate an individual's ability to recognize and react to abnormal operating conditions that might surface while performing those tasks.
- Performance-based qualification methods such as welding and non-destructive testing will be administered in compliance with the applicable regulations and/or recommended practice.

All evaluation methods will utilize a tool, such as a checklist or procedure, to ensure accurate and consistent assessments. Evaluations also consider an individual's physical abilities that are necessary to properly complete of the task, e.g. visual, oral, or hearing capabilities, or other physical requirements. Official records of evaluations are written tests (administered via computer or paper copy), the LPO checklist, and the JSA form. Acceptable evaluation methods will be documented in this program as they are developed and approved.

Work performance history may not be used as the sole method of evaluation at any time (49 CFR 195.509 or 192.809).

If an accepted industry certification program or equivalent that is not identified in this program is used to qualify an individual, the method will be documented on the Alternate Evaluation Method for Individuals form in Appendix 3. This form will ensure the method is adequate, consistent, and meets the acceptable criteria level established for the methods identified in this program. The Company will review each completed Alternate Evaluation Method for Individuals form. If an alternate evaluation method is determined to be acceptable, any individual that meets or exceeds the requirements of the alternate method, and has documentation to substantiate the qualification, will be deemed qualified.

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If an individual prefers, a written test may be administered orally provided that the results of the evaluation accurately reflect the individual's knowledge and skills. The results of the orally administered evaluation method must be entered into the electronic database.

Evaluation methods may vary for transitional, initial, and subsequent qualifications. Any individual that was performing or expected to perform covered tasks prior to October 28, 2002 was required to be qualified by that date (49 CFR 195.509 or 192.809).

- Transitional qualification is that which is completed by October 28, 2002, for individuals who have been performing a covered task on a regular basis prior to October 26, 1999.
- Initial qualification is that done at any time for individuals who were not performing a covered task prior to October 26, 1999.
- Subsequent qualification refers to re-evaluating an individual at an interval established by the Company (e.g., annually, every three years, etc.).

Competency criteria have been established for covered task evaluations. A minimum score of 80% must be achieved for either a written test or number of steps completed correctly during a performance evaluation.

Although training to perform a covered task may be conducted in a group, the evaluation process will be completed on an individual basis. Written evaluations may be given in a group setting; however, the evaluation will reflect an individual's ability.

When new individuals and assets are to be integrated into EMPCo's operations through an acquisition or merger, the covered tasks and evaluation methods in the previous operator's OQ Program will be reviewed by the EMPCo OQ Advisor. Each individual's OQ credentials will be evaluated to determine the compatibility with EMPCo's qualification process. Individuals whose credentials do not satisfactorily comply with EMPCo's qualification process will be required to obtain the applicable qualifications through the evaluation method(s) recognized in EMPCo's OQ Program before performing the covered task(s), unless done so under the span of control of a qualified individual.

Assets integrated into EMPCo's operations through an acquisition or merger will be reviewed to identify applications that were included in the previous operator's OQ Program, however were not covered in EMPCo's OQ Program. The EMPCo OQ Program will be amended as necessary to include additional covered tasks related to newly acquired assets.

A review will also be conducted of operational and maintenance needs to identify whether contractors previously performing covered tasks on such assets will need to be retained. The evaluation and qualification methods for such contractors will be reviewed by the EMPCo OQ Advisor and Contractor Safety Advisor to ensure compliance with EMPCo's requirements is met.

The primary employee qualifications recordkeeping system is Mockingbird. During 2004, ExxonMobil U.S. Distribution (EMUSD) facilities joined EMPCo. Prior to this time, EMUSD employee qualification records were maintained at each DOT terminal. Employees are responsible for ensuring their qualifications are current prior to performing any covered task unless being directed by a qualified individual. Additionally, EMPCo maintains oversight of employee training status, which includes Operator Qualification, via a quarterly report distributed throughout the organization.

Contractors are required to bring their qualifications to each job site. An ExxonMobil representative will ensure the appropriate qualifications are current. In addition, random verifications will be conducted on contract personnel.

Before a contractor begins work, an OQ Covered Task Record (PL-2421) is completed to document the covered tasks being performed and the qualified individual that will either perform the task or direct and observe non-qualified individuals. This process ensures that individuals are qualified in the tasks they are expected to perform. A copy of the OQ Covered Task Record is provided in Appendix 3 and is also available as a standalone form on the Intranet Reference Library in the Forms section.

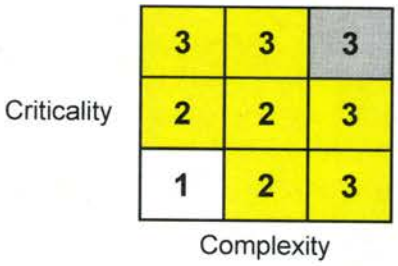
5.1 Evaluation Frequencies

Evaluation frequencies were based on the following process:

- A matrix was developed based on the criticality and complexity of the task to determine the frequency of re-qualification.
- Each task was given two ratings, one for complexity and one for criticality.

5.1.1 Task Rating

Figure 2: Task Rating Chart



Rating Criteria	
1	Low
2	Medium
3	High

- Re-qualification every 5 years for any task that has the lowest rating in both complexity and criticality, i.e. 1-1 (no shade).
- Re-qualification every 3 years for any task that does not have the highest or lowest rating in either complexity or criticality, i.e. 1-2, 1-3, 2-1, 2-2, 2-3, 3-1 and 3-2 (medium shade).
- Re-qualification every year for any task that has the highest rating in both complexity and criticality, i.e. 3-3 (darkest shade).

5.1.2 Task Rating Example

If a task is rated a 1 in complexity and a 2 in criticality, the re-qualification will be every 3 years. If criticality and complexity are both rated a 3, re-qualification will be every year.

Any individual that cannot pass the specified evaluation method(s) for a covered task will not be permitted to perform that covered task, except under the direction/observation of a qualified person. If appropriate/necessary, additional training may be provided to develop the necessary skills and knowledge needed to perform the task before the individual attempts to pass the evaluation methods.

5.2 Non-Qualified Individuals and Span of Control

Non-qualified individuals will not be permitted to complete covered tasks unless a person qualified for the particular task is directing and observing the non-qualified individuals, and the task allows span of control direction and observation. Covered tasks that cannot be performed under the span of control of a qualified person are listed at the end of this section.

To ensure the qualified person can effectively direct/observe the non-qualified individual under a span of control, the following conditions must be met:

- The qualified person must be reasonably close to each non-qualified individual in order to direct and observe his/her work and take immediate corrective action in the event an abnormal operating condition occurs. A qualified person can effectively observe multiple non-qualified individuals performing covered tasks in a close proximity area; however, each qualified individual may not observe more than 5 (five) non-qualified individuals depending upon the task being performed.
- Considerations to address when determining span of control:
  - Size of Work Area
  - Complexity of Task

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- Size of Work Group
- Barriers in the Work Area
- Experience of Work Group

There should also be no obstructions between the non-qualified individuals and the qualified person that would impede the qualified person's ability to directly observe and take immediate corrective action. The qualified person must never loose direct contact with the non-qualified individuals performing the covered task. The qualified person must also be able to communicate effectively with non-qualified individuals who do not speak or understand English, i.e. bilingual communication skills.

Non-qualified individuals may not perform the following tasks, even if being directed or observed by a qualified person:

- Clock Spring repairs
- Welding/welding repairs
- Excavating activities
- Underwater activities
- Performing non-destructive testing

5.3 Contractor and Third Party Personnel (including affiliate companies)

In addition to the Company's OQ requirements, contractor companies must comply with the requirements set forth in the Company's contract or field work order. This includes adopting standards that are equal to or more stringent than the Company's.

Contractor personnel must be qualified prior to performing covered tasks unless a qualified person is directing and observing the non-qualified individuals performing tasks other than the five tasks prohibited in the Section 4.2. The qualified person may be an operator's employee, an operator's representative (third-party inspector), or a contractor.

Contractor personnel must be qualified to perform covered tasks through a program that is identified as acceptable to the Company. Acceptable evaluation methods are identified in Section 5.4.5, External Evaluation Methods. The Acceptance Process for Evaluation Methods form in Appendix 3 must be completed to document the Company's review of any external evaluation method.

If a contractor qualifies their personnel under a program that is not listed in Section 5.4.5 of the Company's OQ Program, the program must be approved by the Company and available for the Company to perform periodic audits before individuals will be allowed to perform covered tasks. Contractors may not use work performance history as the sole evaluation method at any time.

When the Company's affiliates are providing services to the Company under a service agreement, they must meet the requirements of this program.

Before a contractor begins work, a checklist is used to document the covered tasks being performed and the qualified individual that will either perform the task or direct and observe non-qualified individuals. This process ensures that contractors are qualified in the tasks they are expected to perform.

The Company will perform periodic audits of contractors to ensure they are meeting the Company's OQ requirements. These audits may be performed during the Contractor Headquarters Audits, site safety assessments, or as part of our contractor spot check process.

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5.4 Evaluation Methods

Each covered task will have a minimum of one evaluation method. When an individual's performance of a covered task could significantly impact the outcome of the covered task, a performance evaluation may be required in place of a written test or in addition to a written test. The required evaluation method(s) are identified in EMPCo's Written Program.

To ensure employees are able to recognize and react to abnormal operating conditions (AOCs), each evaluation method includes AOCs that could occur while the task is being performed. The evaluation methods ensure the individual is able to recognize and react appropriately to the AOC.

To ensure contractor personnel are able to recognize and react to abnormal operating conditions (AOCs), the Company will conduct an Annual Contractor Orientation that includes material on AOCs. Contractors will receive this information and complete a written examination on AOCs. It is the contractor's responsibility to enter this record into ISNetworld as well as all other OQ records.

5.4.1 Development of Internal Evaluations

EMPCo utilized Company-employed Subject Matter Experts (SME) to develop the internal evaluation methods. Management identified the SME(s) for each covered task. The OQ Advisor worked with each SME to develop the appropriate evaluation method. The steps for developing the evaluation methods are outlined below:

- The OQ Advisor and SME validated the covered task analysis and list of AOCs.
- The OQ Advisor and SME identified all Company-related documents, including written procedures
- The OQ Advisor and SME determined the appropriate evaluation method(s)
- The OQ Advisor and SME began formulating questions based on the covered task analysis and company documents.
- The OQ Advisor and SME ensured there were an appropriate number of questions for each item listed on the covered task analysis and to address AOCs.
- The OQ Advisor validated the test with another SME within the Company to ensure the test was clear, accurate and applicable throughout EMPCo.
- The OQ Advisor formatted the test to allow the test to be entered into the Company's training platform.
- The Training Advisor loaded the OQ test and communicated the availability of the test to the individuals that were expected to complete the test.

The following qualification methods are acceptable under EMPCo's Program as stated below:

5.4.2 Written Exam

A written exam has been developed for each covered task. Written exams are used to determine if an employee has the knowledge and skills needed to perform a covered task and ability to recognize and react to abnormal operating conditions. Written exams may vary in the number of questions contained in each exam. Each written exam is based on the complexity of the task, the criticality of the steps in the task, and the consequences of completing a task incorrectly.

Written exams are self administered through the Mockingbird computer-based training system. Each test is timed to effectively assess an individual's existing knowledge and skills without referencing written materials. An individual will have three attempts to pass each computer-based training system. If an individual does not pass after three attempts, the system will not allow him/her to retake the examination unless the Field Supervisor or a designee unlocks the system. Before a Supervisor or designee unlocks the system, the Supervisor should determine the reason for the failed attempts. After determining the

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reason for the failed attempts, the Supervisor should consider any/all of the following before unlocking the system:

- Review the applicable policy and procedure(s) with the individual
- Assign a qualified individual to work with the individual
- Identify applicable training for the individual

Employees that have been entered into the database may access the system via ExxonMobil Pipeline's Homepage/Applications/Computer Based Training (Mockingbird) after logging onto the network.

If an individual prefers, a written test may be administered orally provided that the results of the evaluation accurately reflect the individual's knowledge and skills. The results of the orally administered evaluation method must be entered into the database. The process for administering evaluations orally is below:

- Field Supervisor or Terminal Supervisor contacts the OQ Advisor and indicates that he/she will be administering an OQ evaluation orally.
- The Supervisor identifies which evaluation and the employee(s) that will complete the evaluation orally.
- The OQ Advisor sends one copy of each evaluation for each employee that will complete the evaluation orally, with the individuals name at the top of the evaluation.
- The Supervisor will administer the test orally, return each evaluation to the OQ Advisor.
- The OQ Advisor will score each evaluation and forward the results to the Training Advisor.
- The Training Advisor will enter the results in the electronic training platform and notify the Supervisor and individuals that completed the oral evaluation of the results.
- The OQ Advisor will maintain a copy of the orally administered test(s).

5.4.3 Performance-Based Evaluations

Performance evaluations can be conducted on-the-job, during on-the-job training sessions, or during simulation exercises.

A performance evaluation must include a demonstration of an individual's abilities necessary to perform a covered task with respect to knowledge and physical capabilities and react to abnormal conditions detected while performing the task. Each performance-based evaluation will reference the written document used to ensure the evaluation is accurate and consistent with other evaluations. These written documents may be written procedures, checklists, or similar documents that a test administrator can follow and ascertain whether the individual is qualified to perform the task. A pass/fail criterion has been established for each performance exam based on the complexity of the task, the criticality of the steps in the task, and the consequences of completing a task incorrectly.

Only authorized individuals will be permitted to administer performance-based tests. Individuals must meet the following requirements before he/she is authorized to administer performance-based tests:

- Understand the written checklists that must be used while conducting a performance based test
- Compare the individual's performance to the required performance criteria identified on the written performance based checklists
- Substantiate an individual's ability to recognize and react to abnormal operating conditions that might surface while performing those tasks

Management has discretion to determine who is authorized to qualify individuals. Generally, it is a Field Supervisor, Terminal Supervisor, or designee that is knowledgeable in an employee's abilities to perform covered tasks.

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After a performance test is passed, the Local OQ Administrator must manually assign credit to the employee in the Mockingbird database to document the qualification. If an individual does not pass the performance-based evaluation, the Supervisor should consider the following:

- Review the applicable policy and procedure(s) with the individual
- Assign a qualified individual to work with the individual
- Identify applicable training for the individual

5.4.4 Alternate Evaluation Methods

EMPCo may allow individuals to be qualified in specific tasks by completing an industry-accepted certification or training program. If an alternate method not identified in EMPCo's OQ Written Program is used, the method must be documented on the Alternate Evaluation Method for Individuals form contained in Appendix 3. The form should be completed by the Field Level Supervisor or designee and forwarded to the OQ Advisor for approval. The OQ Advisor will determine if the alternate method is adequate in ensuring the individual is qualified.

5.4.5 External Evaluation Methods

EMPCo's qualification methods will not be used to qualify contractors and third parties. All other individuals other than EMPCo employees will need to be qualified under the assessments offered by the National Center for Construction and Education Research (NCCER) or other programs that have been audited and accepted by EMPCo.

EMPCo audited several third party OQ Evaluation Programs to determine if they would be acceptable for contractors to utilize. The acceptable third party programs are listed in EMPCo's OQ Written Program and in ISNetworld. Contractors must qualify their employees utilizing one or more of the acceptable methods identified by EMPCo.

Acceptable programs are as follows:

- T.D. Williamson
- Clock Spring
- American Society for Nondestructive Testing (ASNT) (TC1A - Level II)
- Welding Qualifications (API 1104 and ASME Boiler and Pressure Vessel Code, Section IX)
- National Association of Corrosion Engineers (NACE)
- Operator Qualification & Safety Group (OQSG)
- ExxonMobil Production Company
- EIM Controls (EIM) (Gold Seal Service)
- Midwest Energy Association (MEA)
- Englobal
- National Center for Construction Education and Research (NCCER)
- Diver Down Underwater Services (Navigable Water Crossings Only)

Work history is not an acceptable evaluation method at any time for any individual.

5.4.6 External Evaluation Method Audit

Upon a contractor's request, EMPCo will review and evaluate external evaluation methods to determine if contractors could utilize the evaluation method to meet EMPCo's OQ requirements. Below is the process EMPCo utilizes to determine whether an external evaluation method is acceptable.

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- The OQ Advisor requests the evaluation method from the provider/vendor.
- The OQ Advisor cross-references the vendor's evaluations with EMPCo's task list to identify which EMPCo tasks the vendor's program addresses. These are documented on the "Acceptance Process for Evaluation Methods" form.
- The OQ Advisor reviews the initial and subsequent evaluation methods to ensure the methods meet EMPCo's minimum requirements. Methods that do not meet our minimum requirements are not acceptable.
- The OQ Advisor reviews the quality and content of the evaluation methods to ensure the evaluation(s) address all of the elements identified in EMPCo's tasks including abnormal operating conditions. The evaluations are also reviewed to ensure non-relevant information is not included. If the evaluation method does not address all of the elements identified in EMPCo's task, including the abnormal operating conditions or had non-relevant information, the evaluation method is not acceptable.
- The OQ Advisor reviews the pass/fail criteria to determine if the criteria are acceptable. The criteria have to measure a level that would reflect acceptable performance by the individual.
- The OQ Advisor ensures that a written tool is used for each evaluation method identified. If a written tool is not used for each evaluation method, the evaluation method is not acceptable.
- The OQ Advisor ensures the program/evaluations are available for periodic review. If the complete program/evaluations are not available for periodic review, the methods may still be acceptable if EMPCo can verify the integrity and validity of the product by their participation in the development of the product or adequate review of other components of the program, i.e. NCCER.

Any individual that utilizes an external evaluation method must still conform to EMPCo's Written Program, including re-qualification frequencies, post incident re-qualification process, span of control parameters and provide their records through ISNetworld.

5.4.7 External Evaluation Method Provider Audit

EMPCo will contact each provider/vendor of the external evaluation methods to identify any changes to their evaluation methods. If changes have been made, EMPCo will review those changes to determine if those methods will remain acceptable. The OQ Advisor will suspend any contractors' qualifications if an evaluation method is determined to be "not acceptable."

Furthermore, EMPCo will audit each provider/vendor to ensure the information provided during the initial audit is valid/accurate. Any findings will be addressed with the provider/vendor.

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6.0 Field Application of OQ

The requirements of EMPCo's OQ Program apply whenever a task is being performed that meets the four-part test as specified in DOT's Qualification of Pipeline Personnel Rule. These tasks are listed in Appendix 1. In addition to the covered tasks, EMPCo has documented tasks that are not covered under this rule because they do not meet the four-part test. These tasks are also documented in Appendix 1.

Listed below are some general guidelines describing when the OQ rule would not apply.

OQ requirements are not applicable when performing the following tasks:

- **Construction activities:** The OQ rule does not apply to construction activities. Individuals that perform construction activities or covered tasks on systems that have never been in service do not have to be qualified under the OQ Program. A construction task changes to an operations or maintenance task when the pipeline is being commissioned or during the act of connecting to an active regulated system.
- **Removed from pipeline facility:** Individuals that perform activities on DOT regulated pipeline systems that have been physically removed from the pipeline facility do not have to be qualified under the OQ Program.
- **Emergency response:** Only operations and maintenance tasks associated with emergency response are covered. Other task(s) associated with emergency response, for example, site characterization or clean up, are not covered under the OQ requirements.
- **Study tasks or calculations:** Individuals that perform these tasks do not need to be qualified under the OQ Program. Such tasks may include, but are not limited to, determining relief device capacity, converting to service, performing/changing class location surveys, and uprating.
- **Mowing rights-of-way:** Individuals that perform mowing activities do not need to be qualified under the OQ Program unless, in addition to mowing, they are performing a covered task such as the DOT required line inspections and/or placing/maintaining line markers. If individuals are not qualified in right-of-way inspections, they may report undesirable conditions or activities; however, EMPCo may not document the inspection as meeting the inspection requirements in DOT 192 or 195 after October 28, 2002. If individuals are not qualified in placing/maintaining line markers, they may not perform this task except under the direction of a qualified individual.

EMPCo utilizes our OQ Covered Task Record (PL-2421) to verify and identify the qualified personnel preparing to perform the covered task and the non-qualified personnel working under the span of control of a qualified person. The qualified person providing span of control coverage is identified on the form. Each individual/work team must complete an OQ Covered Task Record before each operations and maintenance task that requires a work permit. The OQ Covered Task Record is used to document the covered tasks that will be performed, the qualified individuals that will perform those tasks, or direct and observe non-qualified individuals. The form also documents that each qualified individual is able to recognize and react to abnormal operating conditions and the span of control requirements are being met. The OQ Covered Task Record form is available on the EMPCo Intranet Reference Library.

To ensure employees are able to recognize and react to abnormal operating conditions (AOCs), each evaluation method includes AOCs that could occur while the task is being performed. The evaluation methods ensure the individual is able to recognize and react appropriately to the AOC.

The Company will perform periodic audits of employees and contractors to ensure they are meeting the Company's OQ requirements. These audits may be performed during the Contractor Headquarters Audits, site safety assessments, Environmental, Regulatory, and Safety Assessments, or Job Safety Observations.

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7.0 Roles and Responsibilities

7.1 Affected Personnel

The personnel affected by the Operator Qualification Program include any individual who performs a "covered task" and those who are responsible for implementing the Company's OQ Program.

Individuals who are affected by the qualification program are as follows:

- Contractors
- Delivery/Gauger Personnel
- Engineering Technicians
- Field ERST Technicians
- Field Regulatory Specialists
- Maintenance Technicians (corrosion/electrical/instrumentation/mechanical)
- Multiskill Technicians
- Operations and Maintenance Personnel
- Operations Technicians
- Patrol Pilots
- Pipeline Controllers/Dispatchers
- Safety, Health and Environment
- Supervisors including Lead Persons and Inspectors
- Technical Leaders
- Terminal Mechanics
- Terminal Operators
- Terminal Superintendents
- Welders
- Working Foremen

These individuals have been trained in the Operator Qualification process to ensure they understand their role and the requirements of the program. Roles and responsibilities of affected personnel are provided in the following subsections.

7.2 Supervisors/Area Supervisors/Engineering Managers

- Become familiar with EMPCo's OQ Written Program, including the operations and maintenance activities that are covered under EMPCo's OQ Program.
- Assign only qualified individuals to complete covered tasks unless being directed by a qualified individual.
- Ensure each individual maintains his/her qualifications as needed, including completing random checks on qualifications.
- Identify the covered tasks new or transferred employees will be expected to perform.
- Inform the Local OQ Administrator when a change is made to local operations or maintenance activities that could impact EMPCo's OQ Program.
- Determine when an individual needs to be re-evaluated and re-qualified. This includes the following:

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  - If their performance of a covered task results in an accident as defined in 195 or incident as defined in 192
  - If there is reason to believe an employee is no longer able to perform a task
  - If an individual displays unsatisfactory performance
  - If there is a significant change to equipment, procedures, or a location change. There is more guidance on these items later in this document.
- Conduct performance evaluations as required.
- Complete the paperwork and provide an endorsement when individuals are qualified by alternate methods (internal/external schools) other than those identified in our Program.
- Identify applicable training as needed for individuals that cannot pass evaluation methods.

7.3 OQ Advisor

- Oversee the OQ process for employees and affiliates. This process includes identifying covered tasks as defined by the DOT OQ Rule and communicating EMPCo's expectations and requirements.
- Maintain historical records consistent with the requirements identified in the OQ Program.
- Develop/validate evaluation methods for employees.
- Evaluate and approve/reject as appropriate employees' qualifications by alternate methods.
- Review periodically qualification methods to ensure they are adequately testing the knowledge and skills of individuals and make revisions as needed. This review includes internal and external (outside schools, third parties) qualification methods.
- Assist, as needed, in determining if contractors are qualified to complete covered tasks identified in the project scope, contract, or work procedures.
- Identify/develop training materials to supplement covered tasks and qualification methods.
- Provide guidance to supervisors when determining if an individual needs to be re-qualified or re-evaluated after an incident because of his/her work performance.
- Participate in investigations that are conducted on incidents that occurred while performing covered tasks to ensure OQ process is adequate.
- Conduct the annual review of the OQ Written Program to determine if any revisions are necessary.
- Work with affiliates to identify covered tasks performed for EMPCo and ensure individuals performing covered tasks for EMPCo are qualified and documentation is in place.
- Review the OQ Program of an operator whose employees and assets are to be integrated into EMPCo's operations through a merger or acquisition to evaluate the compatibility with EMPCo's OQ Program.
- Maintain this guidance document and other relevant files for audit and training purposes. This may include rationales on covered or non-covered tasks, revisions to the Written Program, or qualification methods.
- Ensure OIMS Systems reflect OQ requirements and processes.

7.4 Contractor Safety Advisor

- Oversee the OQ process for contractors. This process includes identifying covered tasks as defined by the DOT OQ Rule and communicating EMPCo's expectations and requirements.
- Maintain the ISNetworld database and provide training to individuals that will utilize the database.
- Determine if contractors are qualified to complete covered tasks identified in the project scope, contract, or work procedures.

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7.5 Training Advisor

- Identify/develop training materials to support the OQ Program.
- Assess, periodically and upon request, current training materials to ensure they are adequate in preparing individual with the knowledge, skills, and ability to perform covered tasks.
- Assist the OQ Advisor on all the training aspects identified in EMPCo's Written Program.
- Maintain the Mockingbird database and provide training to individuals that will utilize the database.

7.6 Qualified Employees

- Being familiar with the OQ Program, including what operations and maintenance tasks are covered.
- Completing only the covered tasks in which they are qualified to perform.
- Maintaining their qualifications as specified in the OQ Written Program and Mockingbird System.
- Overseeing or providing feedback to non-qualified individuals as needed.
- Reviewing any changes made to the Written Program or covered tasks prior to performing covered tasks.
- Completing the Annual Verification Process.

7.7 Non-Qualified Employees

- Being familiar with the OQ Program, including what operations and maintenance tasks are covered.
- Completing covered tasks only at the direction of a qualified individual.
- Completing the Annual Verification Process.

7.8 Local OQ Administrators

- Updating/maintaining employees Covered Task Lists upon Supervisor request.
- Generating Reports in Mockingbird as needed/upon request.
- Providing information for random checks.
- Unlocking locked modules (after failed attempts/Supervisor approval).
- Adding tasks to new employees.
- Assigning credit for formal training or orally administered tests.
- Possibly voiding qualifications upon Supervisor or OQ Advisor request.

7.9 Contractors

- Being familiar with EMPCo's OQ Program, including what operations and maintenance tasks are covered.
- Completing only the covered tasks in which they are qualified to perform.
- Providing records in ISNetworld, an electronic web-based database, as specified in EMPCo's OQ Program.
- Reviewing any changes made to the Written Program or covered tasks prior to performing covered tasks.
- Assigning only qualified individuals to complete covered tasks unless a qualified individual is directing an individual.
- Bilingual safety supervision **must** be provided and available at all times when non-English-speaking contract employees will be performing work.
- It is the responsibility of the contractor to translate safety instructions, job procedures, and warnings to non-English-speaking workers.

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7.10 Third Parties

- Being familiar with EMPCo's OQ Program, including what operations and maintenance tasks are covered.
- Completing only the covered tasks in which they are qualified to perform.
- Providing records as specified in EMPCo's OQ Written Program.
- Reviewing any changes made to the Written Program or covered tasks prior to performing covered tasks.
- Assigning only qualified individuals to complete covered tasks.

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8.0 Program Maintenance and Communicating Changes

Changes that affect covered tasks are communicated to the individuals performing those covered tasks and other affected personnel, i.e. supervisors and engineers. This may be accomplished through the Company's Management of Change (MOC) process, distribution of a Record of Revision (ROR) through the electronic mailing system (Lotus Notes), ISNetworld, tailgate meetings, safety meetings, or other communication methods. These communications will be documented to ensure individuals, including contract personnel, affiliates, and third parties performing covered tasks are properly informed.

The Company will evaluate its OQ Program annually to verify its effectiveness. The program may need to be updated more frequently if a change occurs that affects a covered task. The OQ Advisor will consider post accident findings, changes in regulations or new regulations, evaluation method pass/fail analysis (if individuals are consistently having difficulty passing evaluation methods), audit results, equipment upgrades, procedural changes, MOC documents, and any other information that could require a change to a covered task and/or Abnormal Operating Condition.

If it is determined that a qualification method must be modified or added, the OQ Advisor will work with the subject matter expert(s) (SMEs). The OQ Advisor and SME will review the existing covered task list and evaluation methods to determine if the change will be incorporated into an existing qualification method or if a new covered task needs to be developed.

If the change will be incorporated into an existing qualification method or if a new qualification method will be developed, the SME and OQ Advisor will develop the supplemental questions/procedures or the new qualification method. The OQ Advisor will identify the individuals that will need to complete the supplemental evaluation or new qualification by running a report from the Company's computer-based training platform. The report will be sent to the Field Level Supervisors and Terminal Supervisors to validate the individuals listed. After the list has been validated, it is forwarded to the Local OQ Advisors for them to assign the supplemental evaluation to the appropriate individuals.

If the change will result in a new covered task, the OQ Advisor will update the Program and covered task list. The OQ Advisor and SME will perform a Covered Task Analysis on the task. After the Covered Task Analysis is complete, the appropriate evaluation method(s) will be identified and developed. Before the evaluation method is finalized, other SMEs, identified throughout the company, will validate it. The OQ Advisor will request from the Field Level Supervisor the names of the individuals that must be assigned this task. The names will be forwarded to the Local OQ Administrator so they can be entered into the computer-based training platform.

If it is determined that individuals must be evaluated again, the Local OQ Advisor will suspend their qualifications in the computer-based training platform and communicate the status change via Lotus Notes to the impacted individuals and their Supervisor. The individuals must complete the evaluation before performing the covered task.

If it is determined that covered task assignments must be modified, the modifications will be communicated to each individual's Supervisor to ensure the modification is appropriate. If the Field Level Supervisor/Terminal Supervisor agrees with the modification, he/she forwards his approval to the individual and Local OQ Administrator, and the change is made. These changes are also reviewed during the Annual Verification Process.

The company will communicate any changes that impact contractors via ISNetworld or through letters sent directly to the impacted contractors. These communications will be documented in ISNetworld. If necessary, the OQ Advisor will suspend any applicable qualifications in ISNetworld and review the evaluation methods that are currently accepted to determine if they remain appropriate/acceptable.

When significant changes occur, the Company will evaluate the following:

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- Whether existing qualification methods must be modified
- If additional qualification requirements or covered tasks are necessary
- Whether individuals performing the covered task should be evaluated again
- If individual's qualified task inventories need to be revised

All applicable training materials and evaluation materials will be updated as needed to reflect the changes.

The following items will be assessed during the annual review:

- Effectiveness of the OQ Program and the internal evaluation methods
- Content of each covered task and evaluation method
- Re-qualification frequencies

The program may be reviewed more frequently if an incident or near miss occurs as a result of an individual's performance or if individuals impacted by this program identify an improvement opportunity. All revisions to this program will be recorded in the Revision Log beginning on page iii.

Following significant changes to the Written Program, the Company will notify the Pipeline and Hazardous Materials Safety Administration and/or applicable state agency of the modifications. Significant changes that warrant agency notification include:

- A change in the number of covered tasks
- A change in the evaluation methods or criteria for performing covered tasks
- An increase in the number of non-qualified individuals that may perform a covered task under the span of control of a qualified person
- Wholesale changes to the OQ Program, whether due to an overall effort to improve program performance or due to a merger or acquisition that results in incorporating the best features of competing programs.

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9.0 Recordkeeping

Records on individuals and covered tasks will include the following:

- The qualified individual's name
- The covered tasks that the individual is qualified to perform
- The date(s) of current qualification
- The qualification method

Documentation on evaluation methods will be retained in the same electronic database that the Company's training records are maintained. Any individual that has been given access approval to the Company's training database may access the Operator Qualification records. The records may be obtained from any site that has access to the Company's Intranet site.

Documentation supporting the evaluation procedure will be maintained for a minimum of five years after an individual is no longer performing the covered task or leaves the company (refer to 49 CFR Part 192.807b and/or 195.507b).

Contractor companies must provide their records through ISNetworld to ensure the Company can track/maintain documentation on the qualification of their employees unless an exception is obtained. Contractors are also required to bring a recent (within one week) printed copy of their qualifications. ISNetworld is the preferred document; however, other documents may be accepted provided it identifies all the required information. Employees may verify/retrieve contractor qualifications by telephoning ISNetworld at 214-303-4900 or by accessing ISNetworld via the Internet at www.isnetworld.com.

ISNetworld exceptions will be granted to contractors on a limited basis and only for contract companies that perform a limited number of covered tasks at one work location. If an exception is granted, the recordkeeping process for the Contract Company requesting an exception must be documented in the ISNetworld Exception document, and the records must be maintained locally and assessable by the Company at any time.

When a contractor arrives at an EMPCo facility, the individual must provide documentation to indicate their qualifications. If their qualifications meet or exceed EMPCo's requirements, the individual may perform the specified covered tasks. If the individual does not have documentation, the individual will not be permitted to perform any covered tasks until their qualifications are verified or unless directed and observed by a qualified individual.

It is the contractor's responsibility to enter their data into ISNetworld.

Contractors are required to bring their qualifications with them to each job-site and produce them to the ExxonMobil Representative.

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10.0 Continuous Improvement

The Company utilizes various internal review processes to assess compliance and identify continuous improvement opportunities. The appropriate action steps and individuals necessary to implement the improvement opportunities are identified. The OQ Advisor is responsible for facilitating this process and communicating any changes that arise as identified in Section 8.0, Program Maintenance and Communicating Changes.

10.1 OQ Spot Check Process

The OQ Spot Check Process is designed to ensure that EMPCo and contractor employees who perform DOT covered tasks for EMPCo are in compliance with the EMPCo OQ program requirements. This OQ Spot Check Process is part of an ongoing effort to periodically verify compliance with EMPCo's OQ requirements. Spot checks are conducted on a random basis.

Spot Checks are documented and exceptions managed to ensure appropriate corrective actions are resolved as necessary. An individual identified during a spot check performing a covered task for which he/she is not qualified will not be permitted to continue performing the task, except as may be allowed under the span of control of a qualified individual.

The Contractor Safety and Administration Manual includes an explanation of the Operator Qualification Spot Check Process in Section 2, Drug & Alcohol/Security Background/Operator Qualification Spot Checks.

10.2 Program Feedback and Assessments

Feedback addressing the OQ Program is obtained from EMPCo employees and contractors. Issues pertaining to the OQ Program, e.g. evaluation test questions or criteria, recognition of AOCs, contractor compliance, etc., are periodically received from EMPCo employees, Local OQ Administrators, and Contractor Safety Workshop feedback questionnaires. This feedback is reviewed to identify program improvements.

The results of internal assessments will be examined to determine if the covered task evaluations are effectively assessing an individual's knowledge and skills and to identify any additional training opportunities. The results will be analyzed to identify items that are statistically significant.

10.3 Additional ISNetworld Requirements

Contractors are required to bring a printed version of their ISNetworld records to the job-site and currently a picture is not required on the printed version of their records. At this time, an OQ report is encouraged but not required. EMPCo will institute a deadline for contractors to enter their information into an OQ Report and a picture of each Qualified Individual by a pre-determined date. If the contractor does not meet these requirements by the pre-determined date the contractor will be considered restricted from performing OQ work. EMPCo will communicate this requirement to impacted contractors via ISNetworld and/or an EMPCo mailing when complete.

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Appendix 1 EMPCo Covered Task List

The following table lists the covered tasks that satisfy the four-part test, the complexity and criticality of each task, and the re-qualification frequency. Non-covered tasks are listed at the end of the table.

Further details of each task are provided in the Covered Task Analyses in Appendix 2. The rational explaining non-covered task determination is provided in the respective Covered Task Analysis.

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Operator Qualification Covered Task List

Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
1	Inspect, test & calibrate control devices	Pertains to electrical components. Mechanical components are covered in Task 30. Does not include establishing set points.		yes	yes	yes	yes	yes	192.739	195.406 195.428	2	2	5	3 years	written
2	Starting & stopping pumps/compressors locally (includes setting suction and discharge pressures)	Motors and actuators associated with valves, Variable Frequency Drives, local operations, not OCC		yes	yes	yes	yes	yes	192.605	195.402 195.406	2	2	5	3 years	written
4	Opening, closing, monitoring valves; isolating system, (FIELD)	Field task, not OCC		yes	yes	yes	yes	yes	192.605 192.727 192.745 192.747	195.402 195.420 195.426 195.428	3	3	5	Annual	written
5	Installing/Maintaining Control Center SCADA equipment	Associated with the CPM system, includes HUB operations completed from OCC		yes	yes	yes	yes	yes		195.444	2	2	5	3 years	written
6	Shutting down, starting-up, sequencing pipeline systems (OCC only)	Includes monitoring pressure, flow, temperature and valve operations		yes	yes	yes	yes	yes	192.605	195.402 195.406	3	3	5	Simulation - Annually; CBT - every other year	Simulation & Written

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
7	Installing/Maintaining Field SCADA equipment	Excludes HUBs	CPM, API	yes	yes	yes	yes	yes		195.408	2	2	5	3 years	written
8	Purging, flaring HVL's and natural gas			yes	yes	yes	yes	yes	192.605 192.629	195.402	3	3	5	Annual	Written
9	Displacing crude and product pipelines			yes	yes	yes	yes	yes		195.402	1	2	5	3 years	written
10	Odorizing			yes	yes	yes	yes	yes	192.625		1	3	5	3 years	written
11	Launching and receiving in-line inspection tools	Includes scraper and sphere operations	FIMMS	yes	yes	yes	yes	yes		195.452	2	2	5	3 years	written
12	Pressure Testing	Does not include any testing done to pre-test pipe	FIMMS	yes	yes	yes	yes	yes	192.501 192.619 192.621 192.623	195.406 195.300	2	2	5	3 years	written
13	Patrolling lines - air, vehicle, or foot		FIMMS One-Call	yes	yes	yes	yes	yes	192.705 192.721 192.707	195.410 195.412	1	2	5	3 years	written
14	Line locating, placing/maintaining line markers	Includes temporary markings, & probing lines. Excludes locating underwater lines	FIMMS	yes	yes	yes	yes	yes	192.614 192.705 192.721 192.707	195.410 195.442	2	2	5	3 years	written
15	Leakage surveys	Includes both gas and liquids	FIMMS	yes	yes	yes	yes	yes	192.706	195.442	1	2	5	3 years	written
16	Navigable Waterway Crossing Inspections	Includes locating underwater lines	FIMMS	yes	yes	yes	yes	yes	192.612	195.412	2	2	5	3 years	written

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
17	Measuring structure to soil potentials		FIMMS	yes	yes	yes	yes	yes	192.323 192.465	195.565 195.573	1	2	5	3 years	written
18	Determining shorted casing		FIMMS	yes	yes	yes	yes	yes		195.565	2	1	5	3 years	written
19	Inspecting/Monitoring shorted casings		FIMMS	yes	yes	yes	yes	yes		195.565	1	2	5	3 years	written
20	Repairing casings		FIMMS	yes	yes	yes	yes	yes	192.323	195.567	2	2	5	3 years	written
21	Reading rectifiers			yes	yes	yes	yes	yes	192.465	195.567	1	1	5	5 years	written
22	Adjusting, installing, repairing rectifiers & installing and repairing groundbeds			yes	yes	yes	yes	yes	192.465	195.573	2	2	5	3 years	written
23	Inspecting exposed pipe and atmospheric surveys	Includes pipe exposed from excavating, or washout. Includes off-shore risers at the splash zone and above the water line.C35	FIMMS Safety-Related Condition/ Liquids Manual	yes	yes	yes	yes	yes	192.459 192.481	195.583 195.569	2	2	5	3 years	written
24	Installing, replacing, repairing anodes, test leads and bonds	Includes CAD welding		yes	yes	yes	yes	yes	192.465	195.567	1	1	5	5 years	written
25	Installing and removing coupons		FIMMS	yes	yes	yes	yes	yes	192.477	195.579	2	2	5	3 years	written
26	HUB Operations	Field Operations, not OCC	HUB Operations Manual	yes	yes	yes	yes	yes		195.444	3	3	5	Annual	written

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Operator Qualification Covered Task List

Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
27	Coating or recoating pipe	Includes exposed or buried pipe; includes tank painting	FIMMS	yes	yes	yes	yes	yes	192.461 192.479 192.481 192.483	195.573	1	1	5	5 years	written
28	Inspecting, and routine maintenance of valves	Removing valves is not a covered task		yes	yes	yes	yes	yes	192.745 192.747	195.420	1	2	5	3 years	written
29	Repairing and Maintaining Valves	Removing valves is not a covered task, does not include routine maintenance		yes	yes	yes	yes	yes	192.745 192.747	195.422	2	2	5	3 years	written
30	Inspecting, replacing overpressure/overfill control devices	Pertains to mechanical components. Electrical components are covered in Task #1. Task also includes control valves and relief valves.		yes	yes	yes	yes	yes	192.739 192.743	195.428	2	2	5	3 years	written
31	Routine Monthly Inspection of Breakout Storage Tanks		FIMMS Source Inspection Handbook								1	2	5	3 years	written
32	Clock Spring Repairs												0	According to Clock Spring	According to Clock Spring
33	Excavating near facilities and Backfilling	Excludes 3rd party line crossings	One Call	yes	yes	yes	yes	yes	192.317 192.319	195.252 195.422	1	1	0	5 years	written
35	Inspection of In-Service Breakout Storage Tanks	Does not include repairs covered under #3, or monthly inspections covered under Task 31	FIMMS Source Inspection Handbook	yes	yes	yes	yes	yes		195.428 195.432	2	2	5	3 years	written
36	Moving pipelines		P/L Mod.	yes	yes	yes	yes	yes	192.309	195.424	2	2	5	3 years	written

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
37	Welding or repairs to welds on existing lines, includes weld inspection	Includes in-service or out of service. Excludes CAD Welding+C51	Welding Manual	yes	yes	yes	yes	yes	192.245 192.225	195.214 195.226 195.230	3	3	0	Consistent with 1104	Consistent with 1104
38	Performing non-destructive tests	Includes interpreting UT, Dye Penetrant, X-rays, Mag Particle	ASNT SNT-TC-1A	yes	yes	yes	yes	yes		195.228 195.234	2	3	0	Consistent with 1104	Consistent with 1104
39	Hot Tapping Larger than 3"/Stoppling	Does not include taps smaller than 3"		yes	yes	yes	yes	yes			2	3	0	3 years	written
40	Measuring Wall Thickness	Associated with determining wall thickness/corrosion control program.	FIMMS, P/L Mod.	yes	yes	yes	yes	yes		195.579 195.585	2	2	5	3 years	written
41	Repairing and replacing pipelines	Includes temporary or permanent repairs such as: plidco, wraps, sleeves, clamps, flange-ups, laminations, grinding out, hot tapping stoppling, river crossings	P/L Mod.D74	yes	yes	yes	yes	yes	192.309	195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	5	3 years	written
42	Joining plastic pipe	Not performed on pipeline systems at EMPCo.		yes	yes	yes	yes	yes	192.283 192.285	195.8	1	2	0	3 years	written
51	Cathodic Protection Inspection of Underwater Facilities	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
52	Prevent External Corrosion on Underwater Pipelines	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
53	Measure Wall Thickness on Underwater Pipe	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
54	Conduct Underwater Cathodic Protection Remediation	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
55	Conduct Temporary Marking of Underwater Pipelines	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
56	Conduct Underwater Valve Inspection, Maintenance and Repair	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
57	Movement of In-Service Underwater Pipeline	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
58	Abandoning , Safe Disconnect, Purging and Sealing of Underwater Pipelines	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
59	Installation, Replacement or Repair of Support Structures on Underwater Components	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
60	Inspection of Underwater Pipeline Facilities	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
61	Perform Underwater Pipeline Repair Activities	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
62	Operation of an Underwater Assembly	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
63	Perform Underwater Pigging Activities	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG

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Operator Qualification Covered Task List

Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
64	Perform Underwater Flange Mating Procedures	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
65	Perform Underwater Mechanical Hot Tap	Task performed by qualified contractor	OQSG Module	yes	yes	yes	yes	yes		195.557 195.559 195.561 195.563 195.567 195.579 195.581 195.585	2	2	0	3 years	According to OQSG
	Abandoning or deactivating pipeline			yes	no	yes	no	no	192.727						
	Determination of relief devices capacity	This is a calculation, therefore it is not covered.		no	yes	yes	yes	no	192.743	195.428					
	Converting to service	Study tasks are covered elsewhere		yes	no	yes	yes	no		195.500					
	Reporting accidents, incidents, safety related conditions			no	no	yes	yes	no	191.15 191.23	195.50 195.55					
	Inspecting new pipelines			yes	no	yes	yes	no	192.305 192.307	195.204					
	Welding new pipe			yes	no	yes	yes	no	192.227	195.222					

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
	Testing new pipelines			yes	no	yes	yes	no	192.505 192.507 192.509 192.511	195.302					
	Reviewing risk based alternative assessment			no	no	yes	yes	no		195.303					
	Inspecting fire fighting equipment	Includes fixed fire systems		no	no	yes	no	no		195.430					
	Responding to fire, explosion, leak			no	no	yes	yes	no	192.615	195.402					
	Conducting public education program			no	no	yes	yes	no	192.616	195.440					
	Controlling energy; locking out / tagging out	Covered in other tasks		yes	yes	no	yes	no		195.402					
	Entering confined space			yes	no	yes	no	no	192.319	195.402					
	Proving meters			yes	yes	no	yes	no							
	Conducting emergency drills			yes	no	no	no	no	192.615						
	Evacuating the public			no	no	yes	no	no	192.615						
	Reviewing/updating OME			no	no	yes	yes	no		195.402 195.403					
	Preventing damage	Covered elsewhere		yes	no	yes	yes	no	192.614	195.442					
	Taking and analyzing product sample/ composition			yes	yes	yes	no	no		195.418					

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
	Close interval surveys			yes	yes	no	yes	no							
	Analyzing tool runs			no	no	yes	no	no	192.465 192.475 192.477	195.450 195.452					
	Ditching			yes	no	yes	no	no	192.319	195.246					
	Mowing ROW			yes	no	no	yes	no							
	Performing/ changing class location surveys			yes	no	yes	no	no	192.609 192.611 192.613						
	Uprating			yes	no	yes	yes	no	192.555 192.557						
	Customer notifications			no	no	yes	no	no	192.16						
	Excess flow valve notification			no	no	yes	no	no	192.383						
	Provide security			yes	no	yes	yes	no		195.436					
	Measure clearance from existing pipe to underground structures			no	no	yes	yes	no		195.25					
	Inspecting off-shore risers below the water line			yes	yes	no	yes	no							
	3rd party line crossings			yes	no	yes	yes	no							

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Task Number	Task / Procedure	Comments on Task	Reference Material	Four-Part Test				Covered Task	Part 192 Code Section	Part 195 Code Section	Complexity of Task	Criticality of Task	Span of Control	Re-qualification	
				Task Performed on Pipeline	Operations or Maintenance Task	Required by DOT Part 192 or 195	Affects Operation or Integrity of Pipeline							Frequency	EMPCo Method
	Offshore line crossings	Same as "measure clearance from existing PL to underground structures."		no	no	yes	yes	no	N/A	195.250					
	Pipeline span inspections on sea bottom	Not required, performed as an integrity item.		yes	yes	no	yes	no	N/A						
	Offshore riser inspection - underwater	Not required, performed as an integrity item.		yes	yes	no	yes	no	N/A						
	Gulf of Mexico (GOM) (including outlets) depth of coverage survey	* The regulation states, "the inspection must be conducted after October 3, 1989 and before November 16, 1992." Work has been completed. Was originally going to be revised to have reoccurring requirements but has not been done so far. Revision of regulation		yes	yes	no*	yes	no	N/A	195.413					
	Cleaning and gas freeing tanks			yes	yes	no	yes	no	N/A	N/A					
	Vapor Recovery Systems			yes	yes	no	yes	no	N/A	N/A					
	Work on Geodesic Dome Roof			yes	yes	no	no	no	N/A	N/A					

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COVERED TASK ANALYSIS

Task:	Inspect, test and calibrate control devices (electrical)	Task ID#	1
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.406, 195.428, 192.739		

Task Description:

This task consists of the inspection, testing and calibration activities performed on electrical components of pressure and flow control devices to verify they are functioning properly and in good operating condition.

- Inspect/calibrate overfill protective devices (i.e. floats, hi-level alarms, switches, sensing devices)
- Test and calibrate for proper set points
- Inspection, testing and calibration of pressure switches and control valves
- Inspect, test of control valve positioners (including pilot operated devices), sensing devices (transmitters), control loops
- Understanding the importance of documentation

Task Excludes:

- Relief valves - covered in Task #30
- Establishing set points (calculation)
- Evaluating application of device for adequate protection - engineering calculation
- Mechanical components covered in Task #30

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Technicians	Terminal Mechanics	Electrical Technicians
Contract Personnel	Terminal Supervisors	Terminal Operators
Electrical/Instrument Techs	Terminal Operating Techs	Working Foremen

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ1 NCCER -- EIPT written assessment, or PV251, PV252, PV300, PV310, or Module 64206, 66102 OQSG -- CT11, CT26, CT27 MEA -- KNT/PEF 0809, 1305, 1806, 1807, 1803
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure	☒ Yes	☐ No	Fire/Explosion	☒ Yes	☐ No
Activation of Safety Device	☒ Yes	☐ No	Physical System Damage	☐ Yes	☒ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition	☐ Yes	☒ No
Unexplained Status Change	☒ Yes	☐ No	Unexpected Hazardous Liquids	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Starting/Stopping Pumps and Compressors Locally	Task ID# 2
		Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	192.605, 195.402, 195.406	

Task Description:

Elements of this task may include:

- Locally starting pumps/compressors
- Communicate status with OCC
- Ensure line pressure is within allowable limits
- Ensure control devices are operating within allowable limits
- Ensure flow rates are within allowable limits
- Setting suction and discharge pressures and Flow Rates locally
- Monitor station integrity
- Check integrity of equipment (pump or compressor) before and after start-up

Task Excludes:

- Remote start-ups and shutdowns (Task 6)
- Proper alignment of valves (Task 4)

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Technicians	Engineering Techs	Terminal Supervisors
Gaugers	Mechanical Techs	Terminal Superintendents
Pipeliners	Electrical Techs	Terminal Operating Techs
Operator/Gauger	Terminal Operators	Working Foremen
Field Supervisors	Terminal Mechanics	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ2 NCCER -- FCCOT written assessment, or PV431, PV432, PV433, PV434, or Module 65102, 65105, 65106 OQSG -- CT39 MEA -- KNT/PER 1414PS
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Opening, Closing and Monitoring Valves (Field)	Task ID# 4
		Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	192.727,192.745, 192.747, 192.605,195.402, 195.420, 195.426, 195.428	

Task Description:

This task could involve opening and closing of block valves, scraper trap valves, manifold valves, tank valves, pump valves or any other valve used to isolate a system, direct a stream or launch/receive scraper. It also involves remote and manual tasks that are performed in the field.

- Make appropriate notifications
- Verify system and valves to be operated (line-up)
- Monitor and verify safe conditions exist (pressure, preconditions alarm conditions) to operate valves
- Manually or remotely open/close valves
- Document
- Verify normal and safe operating conditions after operation (valves lined up properly, pressure okay)

Task Excludes:

- Relief valves (covered in Task #30) and valves removed to an off-site vendor repair facility.
- Valves operated from OCC

Prerequisite Tasks: None

Personnel That May Complete This Task		
Field Operations Personnel	Terminal Supervisors	
Contractors	Terminal Superintendents	
Terminal Operators	Terminal Operating Techs	
Terminal Mechanics	Working Foremen	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	3	Criticality:	3	Re-qualification Frequency:	1 year

Method of Evaluations	
Initial:	EMPCo -- PLOQ4 NCCER -- FCCOT written assessment or PV434, or Module 65102, 65106 OQSG -- CT39, CT41 MEA -- KNT/PEF1414LR, 1414PS
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

COVERED TASK ANALYSIS

Task: Installing/Maintaining Control Center SCADA Equipment	Task ID# 5
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 195.444	

Task Description:

This task consists of the installation, programming, inspection, and testing of the Central SCADA, Disaster Recovery Center, HUB computers and network equipment. Including the maintenance of the human-machine interface system and leak detection or line integrity system.

Elements of this task include:

- Recognize and troubleshoot network line failures
- Recognize, troubleshoot and resolve Host SCADA or other server hardware failures
- Recognize, troubleshoot and resolve PC SCADA hardware failures
- Recognize, troubleshoot and resolve SCADA,/PC/ or other server software failures
- Recognize, troubleshoot and resolve issues that effect the CPM system
- Recognize, troubleshoot and resolve network equipment failures
- Perform day to day maintenance and testing, configure new pipelines, networks, etc.

Task Excludes:

- Monitoring CPM system by controller and testing of controller reactions which is covered under task #6.

Prerequisite Tasks: None

Personnel That May Complete This Task		
SCADA Support Group		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	Englobal
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☐ Yes	☒ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☒ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

COVERED TASK ANALYSIS

Task:	Shutting down, starting up, sequencing pipeline systems (OCC)	Task ID#	6
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.605, 195.402,195.406		

Task Description:

This task includes activities and procedures that are required for safe and prudent operation when shutting down, starting up and sequencing pipeline systems from OCC.

Elements of this task include:

- Start-up/shutdown
- Maintain pressure within allowable limits
- Monitor flow rates, pressure and temperature
- Monitor communications
- Monitor leak detection and line integrity
- Opening, closing, monitoring valves

Task Excludes:

- Manually opening/closing valves - Task 4
- Excludes Field Operations covered in Tasks 2 and 4

Prerequisite Tasks: None

Personnel That May Complete This Task		
Pipeline Controllers		
Contract Operators		
Field Operations Personnel		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	3	Criticality:	3	Re-qualification Frequency:	1 year

Method of Evaluations	
Initial:	EMPCo -- PLOQ6 NCCER -- FCCOT or PV431, PV432, PV433, PV434 or Modules 65102, 65105, 65106
Refresher:	Simulation - annually Written Test - every other year
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☒ Yes ☐ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☒ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☒ No
Unexplained Status Change:	☒ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☒ No
Communication, Power Interruption/Failure	☒ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

COVERED TASK ANALYSIS

Task:	Installing/Maintaining Field SCADA Equipment	Task ID#	7
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.408		

Task Description:

This task consists of installing, testing, program adjustments and calibrating activities performed on Remote Telemetering Units, process controller or other instrumentation control loop to verify that it is functioning properly, in good operating condition and is adequate for the application.

- Zero span and differential adjustments
- Adjust timers or sequence events
- Implementation of new or revised program (software)
- Verification and checkout with Control Center SCADA system
- Adjust pressure set points
- Documentation requirement
- Adjust PID loop control and program
- On-site changes or corrections to ladder logic and/or statement list program

Task Excludes:

- Mainframe SCADA equipment and programming which is covered in Task #5
- Writing the programs for the equipment (not an operation or maintenance task)
- Hub Operations - Task 26

Prerequisite Tasks: None

Personnel That May Complete This Task		
Electrical/Communications Techs	Terminal Operators	Terminal Operating Techs
Multiskill Techs	Terminal Mechanics	Working Foremen
Contract Personnel including the SCADA Support Group	Terminal Supervisors	
	Terminal Superintendents	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ7 NCCER -- EIPT written assessment, or PV260, PV441, PV442, or Modules 64207, 64209, 66102 OQSG -- CT28, CT40 MEA -- KNT/PEF1808, 2705
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

COVERED TASK ANALYSIS

Task:	Purging, flaring HVLs and natural gas	Task ID#	8
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.605, 192.629, 195.402		

Task Description:

This task consists of steps that must be taken to safely flare (temporary or permanent) and purge HVLs and natural gas. Such steps may be:

- Safe disconnect
- Flaring and purging techniques
- Flaring site preparation (temporary)
- Preventing/minimizing smoke and liquid carry over

Task Excludes:

- Relief valves - covered in Task #30
- Establishing set points (calculation)
- Evaluating application of device for adequate protection - engineering calculation

Prerequisite Tasks: None

Personnel That May Complete This Task	
Multiskill Techs, Tech Leaders	Operations Personnel, Inspectors, Pipeliners
Contract Personnel	Mechanical Techs (for pumps, provers)
Engineering Techs	Field Supervisors

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	3	Criticality:	3	Re-qualification Frequency:	1 year

Method of Evaluations	
Initial:	EMPCo -- PLOQ8 NCCER -- PMT written assessment, or PV361, PV362, PV363, PV500, PV510, or Modules 62309, 66102, 67104, 67105, 67107 OQSG -- CT32, CT48 MEA -- KNT/PEF1401, 1418
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

COVERED TASK ANALYSIS

Task:	Displacing crude and product pipelines	Task ID#	9
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.402		

Task Description:

- This task consists of decommissioning or removing a pipeline facility from service

Task Excludes:

- Purging or flaring HVLs and NGLs

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs, Tech Leaders	Inspectors	Terminal Mechanics
Contract Personnel	Field Supervisors	Terminal Supervisors
Engineering Techs	Mechanical Techs (for pumps, provers)	Terminal Superintendents
Operations Personnel		Terminal Operating Techs
Pipeliners	Terminal Operators	Working Foremen

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ9 NCCER -- PMT written assessment, or PV361, PV362, or Module 62309, 66102 OQSG -- CT32 MEA -- KNT/PEF1401
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☒ Yes ☐ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☒ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☒ No
Unexplained Status Change:	☒ Yes ☐ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☒ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

COVERED TASK ANALYSIS

Task:	Odorization	Task ID#	10
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.625		

Task Description:

- Determine the odorant rating of the odorometer effluent.
- Monitor the level of mercaptan in storage vessel.

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Utility Operator - Gauger		
Operator Gauger		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Requalification					
Complexity:	1	Criticality:	3	Requalification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ10 NCCER -- PV570, PV580, or Module 67104, 67105, 67107,or Module 67104, 67105 OQSG -- CT52
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Launching and Receiving In-Line Inspection Tools	Task ID#	11
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.452		

Task Description:

- Isolating the pipeline barrel
- Relieving pressure
- Inserting/removing inspection device
- Pressurizing the barrel
- Launching the inspection device

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Operators/Gaugers	Contractors	
Construction Techs	Pipeliners	
Multiskill Techs		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ11 NCCER -- PMT written assessment, or PV291, PV292, or Modules 62203, 62303, 66102 OQSG -- CT41 MEA -- KNT/PEF1414LR
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☒ Yes ☐ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☒ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☒ No
Unexplained Status Change:	☒ Yes ☐ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☒ Yes ☐ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Pressure Testing	Task ID# 12
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.501, 192.619, 192.621, 192.623, 195.300, 195.406	

Task Description:
This task consists of the activities involved in pressure testing pipelines or segments of pipelines to assure the structural integrity of pipe and piping components. This task is also used to verify the integrity of an existing pipeline system after it has been placed in operation or prior to changing the service of a pipeline system. This task pertains to the individuals leading the pressure test. Others involved will be qualified in the covered tasks they will be expected to perform. This task could include the following:

- Calibration of Test Instruments
- Operating a deadweight pressure indicating device
- Pressuring up the piping to within pre-established pressure limits and monitoring test pressure to remain within those limits
- Recognition of possible leaking piping due to pressure loss during test
- Recording and retaining pressure test data (during the test)

Task Excludes:

- Preparation of Pressure Testing Plans including Selection of Testing Fluid
- Preparation of permanent pressure test reports and documentation
- Calculation of stresses in piping from test pressure and Maximum Operating Pressure (MOP)
- Determination of Maximum Operating Pressures (195.406)
- Pretesting of Pipe for Emergency Stock
- Pressure Testing of New Pipelines
- Evaluation of Risk Based Alternatives to Pressure Testing by establishing 1. Location Risk Factors, 2. Product Risk Factors, 3. Volume Risk Factors, 4. Probability of Failure Indicators, and 5. Pipe Manufacturing Methods
- Determination of Minimum and Maximum Test Pressures
- Verification calculations to determine if piping is leaking from pressure & temperature readings
- Writing the test report
- Operational Task when an integrity problem is suspected - covered in Task 6

Prerequisite Tasks: None

Personnel That May Complete This Task			
Field Supervisors	Mechanical Technicians	Terminal Operators	Terminal Operating Techs
Engineering Technicians	Contractors	Terminal Mechanics	Working Foremen
Inspectors	Tech Leaders	Terminal Supervisors	
Multiskill Technicians	Pipeliners	Terminal Superintendents	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification		
Complexity: 2	Criticality: 2	Re-qualification Frequency: 3 years

Method of Evaluations		
Initial:	EMPCo -- PLOQ12 NCCER -- PMT written assessment or PV410, or Module 62207, 66102	OQSG -- CT37 MEA -- KNT/PEF1301
Refresher:	Same as initial	
Internal Pass/Fail Criteria: 80%		

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Patrolling Lines	Task ID# 13
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.705, 192.721, 192.707, 195.410, 195.412	

Task Description:

Rights-of-way and adjacent areas are inspected at a minimum of 26 times a year. Patrolling lines may be completed by walking, air patrol, vehicle patrol or other appropriate means. Specific tasks include:

- Visual inspection
- Knowledge of reporting/documentation requirements
- Familiar with encroachment policies
- Knowledge of acceptable right-of-way conditions
- Detecting potential releases
- Identifying line markers
- Identify line location

Task Excludes:

- One call responses

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs, Tech Leaders	Air Patrol Pilots	Terminal Superintendents
Contract Personnel	Line Walker/Rider	Terminal Operating Techs
Engineering Techs	Terminal Operators	Working Foremen
Pipeliners	Terminal Mechanics	
ROW Maintenance Techs	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ13 NCCER -- PMT written assessment, or PV151, PV152, or Module 62201, 66102 OQSG -- CT16L (liquid) MEA -- KNT/PEF1204
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure	☒ Yes ☐ No	Fire/Explosion	☒ Yes ☐ No
Activation of Safety Device	☐ Yes ☒ No	Physical System Damage	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition	☒ Yes ☐ No
Unexplained Status Change	☐ Yes ☒ No	Unexpected Hazardous Liquids	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Leakage Surveys	Task ID# 15
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	192.706, 195.442 (195.442 requires a leakage survey after blasting)

Task Description:
This task consists of the inspection activities that are performed on DOT regulated pipelines to ensure the safe operations of a pipeline:

- Knowledge of release recognition and notification
- Knowledge of leak detector equipment
- Utilize leak survey techniques

Task Excludes:

- Documentation of leak survey
- Monitoring the pipeline system line balance, leak detection covered in Task #6.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Technicians	Corrosion Techs	Terminal Superintendents
Contract Personnel	Inspectors	Terminal Operating Techs
ROW Maintenance Techs	Terminal Operators	Working Foremen
Air Patrol	Terminal Mechanics	
Pipeliners	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ15L or EMPCo PLOQ15G NCCER -- PMT written assessment, or PV181, PV182 for liquids or PV521, PV522, PV523 for gas, or Module 62206, 66102, 67107 OQSG -- CT20 for liquids or CT16G (gas), CT45 for gas MEA -- KNT/PEF0804, 1201, 1204, 1206
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Navigable Water Crossing Inspections	Task ID#	16
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.612; 195.412		

Task Description:
This task consists of the activities involved in inspection of pipelines crossing navigable streams or waterways to evaluate the condition of the crossing and assure the structural integrity of the pipeline. This inspection is designed to recognize dangerous conditions or the approach of dangerous conditions resulting from channel movement or bank erosion that could result in damage to a pipeline in the vicinity of a waterway. This task could include the following:

- Establish vertical and horizontal control monuments on each side of a waterway to use in measuring the location of the pipeline with respect to the earthen banks, streambed, and waterway elevation.
- Accurately measure and record the pipeline horizontal and vertical alignment, depths of cover, and waterway profile and alignment
- Locating underwater lines/Using sonar equipment
- Requirement to document the inspections and detailing the condition of the crossing and remedial action or problem areas for additional consideration by operator.

Task Excludes:

- Visual Inspection of Right -Of-Way conditions via Aerial or Ground Patrols covered in Task #13.
- Preparing a list of rivers, navigable streams, or tidally influenced waterways that the pipeline system crosses
- Preparing drawings that depict the vertical and horizontal location of the pipeline with respect to the waterway channel and banks.
- Recognize developing problems such as bank erosion, channel movement, debris collection or abnormal water flow that could impact the integrity of the pipeline crossing
- Determine if additional underwater diver inspections are required (covered tasks of other underwater operations: Tasks 51 to 65)

Prerequisite Tasks: Task 14

Personnel That May Complete This Task		
Field Operations Personnel	Inspectors	
Engineering Technicians	Contractor Personnel	
Surveyors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ16 NCCER -- PMT written assessment, or PV161, PV162, PV163, or Module 62201, 66102 OQSG -- CT17 MEA -- KNT/PEF1205
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Measuring Structure to Soil Potential	Task ID#	17
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.323, 192.465, 195.565, 195.573		

Task Description:
- Knowledge of Pipe Systems (maps, locations of rectifiers, test points, insulating flanges, valves)
- Understanding the use of electrical multi-meters to take direct current voltage measurement between structure (positive side of meter) and copper sulfate reference cell (negative-side of meter). Be sure to indicate value of reading
- Special attention given to ensure rectifier outputs are at proper levels prior to survey. This includes reading both sides of insulating flange locations, casing readings where available, foreign line crossings or bonds (amps are very important and direction of flow)
- Requirement to document result
- Structure to soil readings

Task Excludes:
- Analyzing pipe to soil values or adjusting rectifier output or bond current (covered by Task 22)
- Determine shorted casings (covered by Task 18)

Prerequisite Tasks: Task 21

Personnel That May Complete This Task		
Corrosion Techs	Contractor	
Multiskill Techs	Engineering Techs	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ17 NCCER -- CPFT1M written assessment, or PV011, PV031, PV032, or Module 61108, 66102 OQSG -- CT01, CT03, CT04, CT05, CT08 NACE -- CP1 MEA -- KNT/PEF0505, 0511, 0512, 0514, 0516
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Determining Shorted Casings	Task ID#	18
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.565		

Task Description:
- Relation of pipe to soil and casing to soil readings
- Pass current between casing and pipe and determine resistance value
- Pan Handle Eastern Method
- Determining metallic and electrolytic

Task Excludes:
- Repairing shorted casings (covered by Task 20)
- Determining location of contact between casing and pipeline

Prerequisite Tasks: None

Personnel That May Complete This Task		
Corrosion Techs	Contractors	
Multiskill Techs	Engineering Techs	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	1	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ18 NCCER -- CPFT1I, CPFT1M written assessment, or PV011, PV014, PV021, PV031, PV032, or Module 61108, 61109, 66102 OQSG -- CT01, CT02, CT03, CT05 NACE -- CP1 MEA -- KNT/PEF0503, 0505, 0511, 0512, 0514, 0516
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Inspecting/Monitoring Shorted Casings	Task ID#	19
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.571, 195.573		

Task Description:
- Using an air monitor/gas detector
- Determine/interpret air readings
- Document results
- Make notifications as needed.

Task Excludes:
- Repairing shorted casings (covered by Task 20)

Prerequisite Tasks: None

Personnel That May Complete This Task

Corrosion Techs	Engineering Techs	
Multiskill Techs		
Pipeliners		

Application of the Four-Part Test for Covered Task

This task is performed on a pipeline facility	☒ Yes ☐ No
This is an operations and maintenance task	☒ Yes ☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes ☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes ☐ No

Frequency of Re-qualification

Complexity: 1 Criticality: 2 Re-qualification Frequency: 3 years

Method of Evaluations

Initial: EMPCo -- PLOQ19

Refresher: Same as initial

Internal Pass/Fail Criteria: 80%

Abnormal Operating Conditions

Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Repairing Casings	Task ID# 20
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.323, 195.575	

Task Description:
- Verify test lead connections
- Check casing ends to ensure they are not contacting the carrier pipe
- Install casing spacers
- Fill annulus between casing and carrier pipe full of dielectric fluid
- Replacing casings
- Remove casing
- Install casing seals/vents
- Extend existing casing
- Install a new casing

Task Excludes:
- Determining shorted casings (Task 18)
- Determining where the casing is shorted
- Exposing a line (Task 33)

Prerequisite Tasks: None

Personnel That May Complete This Task		
Corrosion Techs	Engineering Techs	Construction Techs
Multiskill Techs	Contractors	
Pipeliners	Welders	
Tech Leaders	Field Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ20 NCCER -- CPFT1I written assessment, or PV095, or Module 61204, 62304, 66102 OQSG -- CT08 NACE -- CP2 MEA -- KNT/PEF0515
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Reading Rectifiers	Task ID# 21
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.465, 195.567, 195.571, 195.573	

Task Description:
- Electrical hazards associated with rectifiers
- Obtain the DC current (amps), voltage readings and kilowatt-hour A/C meter reading
- Identifying obstructions that can limit air flow
- Requirement to Document

Task Excludes:
- Adjusting outputs (covered by Task 22)
- Repairing rectifiers (covered by Task 22)

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Personnel	Field Supervisors	Terminal Superintendents
Operators	Terminal Operators	Terminal Operating Techs
Corrosion Techs	Terminal Mechanics	Working Foremen
Pipeliners	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	1	Re-qualification Frequency:	5 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ21 NCCER -- CPFT1M, CPFT2 written assessment, or PV031, PV032, or Module 61108 OQSG -- CT03 NACE -- CP1 MEA -- KNT/PEF0505
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☐ Yes ☒ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☐ Yes ☒ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Adjusting, Installing, Repairing Rectifiers and Installing and Repairing Groundbeds	Task ID#	22
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.465, 195.573		

Task Description:
- Knowledge and understanding in electrical codes and principles,
- Multi-meter functions and usage
- Adjust voltage and tap settings
- Resistance measurement (soil and conventional)
- Conversion of A/C power to D/C power
- Electrical breakers and fuses
- Interference testing with foreign structures and stray current effects
- Cathodic protection principles

Task Excludes:
- Pipe to soil readings (Task 17)

Prerequisite Tasks: Task 17 and Task 24

Personnel That May Complete This Task		
Corrosion Techs	Terminal Operators	Terminal Superintendents
Contractors	Terminal Mechanics	Terminal Operating Techs
Engineering Techs	Terminal Supervisors	Working Foremen

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ22 NCCER -- CPFT1M, CPFT2, CPFT3 written assessment, or PV011, PV041, PV042, PVO43, PV093, PV094, or Module 61108, 61201, 61202, 66102 OQSG -- CT01, CT04, CT08 NACE -- CP2 MEA -- KNT/PEF0501, 0512, 0514, 0515, 0516, 1404
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task:	Inspecting Exposed Pipe and Atmospheric Surveys	Task ID#	23
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.459, 192.481, 195.569, 195.583		

Task Description:

- Thoroughly inspect for any physical damage (supports, pipe joints and all components)
- Inspect for soil to air interface areas, injection points, safety valves and associated piping
- Inspect for evidence of external corrosion
- Inspect condition of coating
- Install, repair, replace support structures
- Requirement to document
- Using pit gauge
- Includes off-shore risers at the splash zone and above the water line

Whenever a covered pipeline is uncovered, it must be thoroughly inspected by a qualified individual. When there is evidence of significant corrosion, the person responsible for corrosion must be notified. The responsible person investigates the extent of corrosion. Condition of the coating and extent of external corrosion must be properly documented and retained for the life of the pipeline.

Task Excludes:

- Abandoned pipelines
- Tanks (covered by Task 31)
- Off-shore risers below the water line

Prerequisite Tasks: None

Personnel That May Complete This Task		
ROW Maintenance Techs	Corrosion Techs	Terminal Superintendents
Multiskill Techs	Pipeliners	Terminal Operating Techs
Contractors	Terminal Operators	Working Foremen
Engineering Techs	Terminal Mechanics	
Operations personnel	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ23 NCCER -- CPFT1I, CPFT1M, CPFT2 and PMT written assessments, or PV051, PV052, PV053, PV071, PV081, PV083, PV370, or Module 61104, 61105, 61106, 62204, 62304, 66102 OQSG -- CT07, CT10, CT14, CT33 NACE -- CP1, CIP SI MEA -- KNT/PEF0402, 0405, 0806, 0808, 1424
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Installing replacing repairing anodes, test leads and bonds	Task ID#	24
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.465, 195.567		

Task Description:
- Recognize electrical discontinuity
- Inspection and electrical test of bonds
- CAD welding attachments to a pipeline

Task Excludes:
- Groundbeds covered in Task # 22
- Shorted Casings covered in Task #19 and #20
- Measuring Pipe to Soil Readings covered in Task #17

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill	Field Supervisors	
Pipeliners	Engineering Techs	
Corrosion Techs	Contractors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	1	Re-qualification Frequency:	5 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ24 NCCER -- CPFT1I, CPPFT1M, CPFT2, CPFT3 written assessment, or PV021, PV022, PV023, PV024, PV091, PV092, or Modules 61109, 61201, 61203, 66102 OQSG -- CT02, CT08 NACE -- CP2 MEA -- KNT/PEF0503, 0515, 1404
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☐ Yes ☒ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Installing and removing coupons	Task ID# 25
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.477, 195.579	

Task Description:
This task consists of the isolation, removing and/or installing of corrosion coupons for the purpose of monitoring the effects/extent of internal corrosive activity, and help ensure the operating integrity of DOT regulated pipelines and pipeline systems. This task also provides opportunity to determine the effectiveness of corrosion inhibitors where utilized. This task could involve the following:

- Installation and removal methods
- Collection/Packaging of coupons for third party analysis
- Requirement for documenting inspection, installation replacement activity/results
- Control the injection rate of the inhibitor
- Recommissioning isolated line sections, coupon housings, traps
- Replacing coupons
- Install/remove monitor probe
- Monitor the injection rate of the inhibitor

Task Excludes:

- Determining the type of coupon installed
- Inspecting coupons for loss of mass, surface area, or thickness

Prerequisite Tasks: None

Personnel That May Complete This Task		
Corrosion Techs	Contractors	Welders
Multiskill Techs	Mechanical Techs	
Tech Leaders	Pipeliners	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ25 NCCER -- CPFT1I, CPFT1M written assessments, or PV101, PV102, PV11O, or Module 61111, 66102 OQSG -- CT09, CT12 NACE -- CP1 MEA -- KNT/PEF0401, 0403, 1422
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	HUB Operations	Task ID#	26
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.444		

Task Description:
This task includes the functionality regarding HUBs and the necessary tools to enable field personnel to utilize the HUB in a daily operational mode. This includes logging in, understanding the color codes, navigating within the application, taking control, trending and leak detection and batch tracking.

Task Excludes:
- Operations conducted from OCC

Prerequisite Tasks: None

Personnel That May Complete This Task		
Operators	Multiskill Technicians	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	3	Criticality:	3	Re-qualification Frequency:	1 year

Method of Evaluations	
Initial:	EMPCo -- PLOQ26
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☒ No	Fire/Explosion:	☐ Yes	☒ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☒ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Coating or Recoating Pipe (includes tank painting)	Task ID# 27
		Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	192.461, 192.479, 192.481, 192.483, 195.238, 195.557, .559, .561, .581	

Task Description:
This task consists of proper preparation of pipe and application of pipe coating which meets the requirements referenced in the DOT paragraphs listed above. Specific task requirements and/or procedures can be found in the current General Specifications as well as other sources. This task may involve:

- Surface preparation techniques (sandblasting, wire brushing, etc.)
- Knowledge of coating applications and materials
- Applying coating materials (spraying, brushing, etc.)
- Working with mastics, epoxies, solvents, catalysts, coating tape
- Thermosetting coatings

Task Excludes:

- Using scaffolding and asbestos removal
- Coating new systems or new tanks
- Inspection of Coating covered in Task 23

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Pipeliners	Terminal Operating Techs
Tech Leaders	Terminal Operators	Working Foremen
Project Leaders/Inspectors	Terminal Mechanics	
Field Supervisors	Terminal Supervisors	
Contractors	Terminal Superintendents	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	1	Re-qualification Frequency:	5 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ27 NCCER -- CPFT1I, PMT or PV072, PV073, PV074, PV075, PV076, PV130, PV131, PV132, PV133, PV134, PV135, or Module 61106, 61107, 61206, 61207, 61208, 66102 OQSG -- CT06, CT14 NACE -- CIP SI MEA -- KNT/PEF0402, 0404, 0407, 192-0402
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Inspecting and Routine Maintenance of Valves	Task ID#	28
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.745, 192.747, 195.420		

Task Description:
This task consists of the routine maintenance activities performed on each valve that is necessary for the safe operation of a pipeline. This applies to block valves, manifold valves, tank valves, pump suction/discharge valves, check valves, pressure control valves, and any other valves except relief valves.

- Verify location of valve inspected
- Check accessibility of valve
- Verify valve number
- Check for leaks, damage and corrosion
- Operate valve to verify proper operation
- Relock/secure if needed
- Document inspection
- Maintenance or adjustment of the valve actuator
- Winterization of valves, Lubrication and or packing
- Draining valve body

Task Excludes:

- Relief valves covered in Task #30.
- Valves removed to a vendor's off-site facility.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Pipeliners	Terminal Supervisors
Contractors	Field Supervisors	Terminal Superintendents
Tech Leaders	Terminal Operators	Terminal Operating Techs
Mechanical Techs	Terminal Mechanics	Working Foremen

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ28 NCCER -- MPT written assessment, or PV191, PV192, PV193, PV194, PV195, PV196, PV197, PV201, PV202, PV203, PV204, PV211, PV214, PV215, or Module 63107,63204,63306, 63307, 63308, 64208,66102 OQSG -- CT22, CT42 MEA -- KNT/PEF1427VI, 195-1427VM, 192-1427
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Repairing and Maintaining Valves	Task ID#	29
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.745, 192.747, 195.422		

Task Description:
This task consists of the repair and non-routine maintenance activities performed on a valve in-service on an existing pipeline system. This task may include:

- Familiar with valve components
- Repair of relief valve sensing or control devices
- Cleaning/Inspection of valve internal components
- Repair or replacement of failed or worn components
- Re-assembly of valve and return to operating condition
- Disassembly of a valve
- Familiar with repair manuals/resources (proper parts replacement, repair methods
- Tool selection (non-sparking, intrinsically safe)
- Proper valve isolation procedures
- Proper ID of a valve

Task Excludes:

- Repairs performed when the valve has been removed to an offsite vendor repair facility
- Routine Maintenance covered in Task # 28

Prerequisite Tasks: None

Personnel That May Complete This Task		
Mechanics	Tech Leaders	Terminal Superintendents
Multiskill Techs	Terminal Operators	Terminal Operating Techs
Field Supervisors	Terminal Mechanics	Working Foremen
Contractors	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ29 NCCER -- MPT written assessment, or PV212, PV213, PV214, PV215, PV231 or Module 63204, 66102 OQSG -- CT23 EIM Gold Seal Service MEA -- KNT/PEF1427VR
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Inspecting, replacing overpressure/overfill control devices (mechanical components)	Task ID#	30
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.739, 192.743, 195.428		

Task Description:
These tasks consist of the inspection, testing and replacing the mechanical components of overpressure and overfill protective devices to verify they are functioning properly and in good operating condition. It also includes pressure recording devices. This task may include:

- Identify proper set points on pressure relief valves
- Inspect, test, replace, adjust, tag relief valves
- Replacement of rupture discs
- Verify location of valve to be inspected
- Adjust a relief valve setting
- Calibration equipment - dead weight testers
- Requirement for documenting results
- Changing output of mainline pump when it is the sole pressure control device
- Pressure recording devices (charts and electronic)
- Inspect test calibrate PCD switches and controllers

Task Excludes:

- Establishing set points (calculation)
- Repairing internal components of relief valve (Covered Task 29)
- Evaluating application of device for adequate protection (engineering function)
- Design capacity

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Tech	Contractors	Terminal Superintendents
Tech Leaders	Terminal Operators	Terminal Operating Techs
Mechanical Tech	Terminal Mechanics	Working Foremen
Instrument/Mechanical Tech	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ30 NCCER -- MPT written assessment, or PV220, PV240, PV231, PV232, or Module 63205, 66102 OQSG -- CT11, CT24, CT25, CT26 MEA -- KNT/PEF0809, 1501, 1803, 1804, 1805, 1806
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☒ Yes ☐ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☒ Yes ☐ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☒ Yes ☐ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☒ Yes ☐ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task:	Routine Monthly Inspection of Breakout Storage Tanks	Task ID#	31
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.		

Task Description:
This task consists of the routine external inspection performed each month on regulated breakout storage tanks that are used for hazardous liquid storage.

Task Excludes:
- In-service breakout storage tank inspection covered in Task 35
- Non-regulated tanks
- API 653 tank inspections since inspectors are certified under a separate certification program.
- Tank repairs covered in Task #3.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Inspectors	Terminal Supervisors
Welders	Engineering Techs	Terminal Superintendents
Contractors	Supervisors	Terminal Operating Techs
Pipeliners	Terminal Operators	Working Foremen
Operators/Gaugers	Terminal Mechanics	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ31 NCCER -- PMT written assessment, or PV271, or Module 62202, 66102 OQSG -- CT18 API 653 -- Certified Inspector MEA -- KNT/PEF0810
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Clock Spring Pipeline Repairs	Task ID#	32
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195.581, 195.585, 192.309		

Task Description:
- This task includes the preparation and installation of composite sleeves for the purpose of pipeline repair and reinforcement. This task is limited to and performed according to the process and training specifically required by the Clock Spring Company.

Task Excludes:
- Pipeline repairs performed according to Task 41, Repairing/Replacing Pipelines

Prerequisite Tasks: None

Personnel That May Complete This Task	
Contractors certified by Clock Spring Company	
Employees certified by Clock Spring Company	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	Clock Spring certification
Refresher:	Same as initial
Internal Pass/Fail Criteria:	80%

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Excavating Near Facilities and Backfilling	Task ID#	33
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	192.317, 192.319, 195.252, 195.422		

Task Description:

Exposing a Line	Backfilling
• Knowledge of state-one call requirements • Using spotting equipment, boring equipment • When heavy equipment or hand digging is used • Familiar with safe excavation practices	• Inspection of backfill or debris • Ensuring the line is adequately supported • Backfill worked around and under the line • Determining when select fill is used

Task Excludes:
- Locating and marking the line covered in Task #14
- When Company facilities are being crossed by a 3rd party, Company will follow our One-Call Procedures and Encroachment policy.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Contractors	Terminal Mechanics
Inspectors	Field Supervisors	Terminal Supervisors
Tech Leaders	Pipeliners	
Electrical Techs	Backhoe Operators	
Instrument/Mechanical Techs	Terminal Operators	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	1	Re-qualification Frequency:	5 Years

Method of Evaluations	
Initial:	EMPCo -- PLOQ33 NCCER -- PMT Written assessments, or PV320, PV390, or Module 62107, 66102 OQSG -- CT35 MEA -- KNT/PEF1402
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task:	Inspection of In-Service Breakout Storage Tanks	Task ID#	35
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.428, 195.432		

Task Description:
This task consists of the inspection activities performed on each regulated breakout storage tank that is used for hazardous liquid storage. This inspection applies to the containment firewall, storm water drainage valves and lines, lines leading into and out of tank. Also areas within the tank firewall surrounding the tank, tank valves within the firewall, roof drain valves, tank shell and appurtenances, tank foundation, stairways, roof (floating or fixed), floating roof seals, roof drainage, roof vents, gauge lines and hatches. It also includes any other tank appurtenances on DOT tanks.

- In-service inspection of each DOT regulated breakout storage tank.
- Detection of deterioration of deficiencies in tank areas, firewall, tank shell, stairs, tank bottom, tank roof, tank foundation and tank appurtenances
- Requirement to document the inspection

Task Excludes:

- Non-regulated tanks
- API 653 tank inspections since inspectors are certified under a separate certification program
- Tank repairs covered in Task #3
- Routine Monthly Tank Inspection covered in Task 31
- Vapor Recovery Units

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Inspectors	Terminal Supervisors
Engineering Techs	Welders	Terminal Superintendents
Contractors	Supervisors	Terminal Operating Techs
Pipeliners	Terminal Operators	Working Foremen
Operators/Gaugers	Terminal Mechanics	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ35 NCCER -- PMT written assessment, PV272 or Module 62202, 66102 OQSG -- CT18 API 653 -- Certified Inspector MEA -- KNT/PEF0810
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task: Moving Pipelines	Task ID# 36
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 192.309, 195.424	

Task Description:
This task includes activities required to move or reposition (raise, lower or lateral) a section of pipeline that has not been abandoned. This task may include:

- Techniques to minimize secondary stresses to a pipeline
- Techniques to minimize the possibility of damage to a pipeline or its coating
- Techniques to protect the public (attending valves) against hazards in moving pipelines containing HVLs
- Pipe moving techniques (hand, come-alongs, heavy equipment)
- Knowledge of pipeline pressures required to move a line (based on type of product)
- Supporting the pipe properly

Task Excludes:

- Developing the profile and completing a stress analysis (engineering functions)

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Techs	Tech Leaders	Field Supervisors
Pipeliners	Welders	
Inspectors	Contractors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ36 NCCER -- PMT written assessment or PV331, PV332, PV333, PV340, or Module 62302, 62305, 66102 OQSG -- CT29, CT30 MEA -- KNT/PEF1402
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Welding or repairs to welds on existing lines	Task ID# 37
		Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	195.214, 195.222, 195.226, 195.230, 192.225, 192.245, 192.245	

Task Description:
This task includes all activities and procedures that are required for maintenance welding jobs performed on lines that have not been abandoned or new construction. This task also applies to welding on breakout storage tanks. This task may include:

- Repair and/or removal of arc burns
- Repair and/or removal of defective welds
- Tie-in welds
- Fittings
- Patches
- Visually inspecting welds
- Full encirclements/weld wraps
- Welding Stopples onto the line
- Weld + ends
- Weld wraps
- Welded repair sleeves
- Welding on replacement pipe segments/joints (replacement in kind)

Task Excludes:
- Shop welding
- CAD welding attachments
- Mechanical sleeves covered in Task #41
- New construction

Prerequisite Tasks: None

Personnel That May Complete This Task

Welders	Terminal Mechanics	Terminal Operating Techs
Contractors	Terminal Supervisors	Working Foremen
Terminal Operators	Terminal Superintendents	

Application of the Four-Part Test for Covered Task

This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification

Complexity:	3	Criticality:	3	Re-qualification Frequency:	1 year
				Re-qualification Frequency for API or ASME:	6 months

Method of Evaluations

Initial:	EMPCo -- PLOQ37 NCCER -- PMT written assessment, or PV421, PV422, PV423, PV424, PV425, PV426, or Module 62308, 66102 OQSG -- CT38 MEA -- KNT/PEF1421, 2401, 2402 API 1104 welder certification ASME Boiler and Pressure Vessel Code, Section IX welder certification
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions

Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Performing Non-Destructive Tests	Task ID# 38
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s): 195.228, 195.234	

Task Description:
This task consists of inspection activities (other than visual) required after various welding activities or when the line has been exposed. The task includes conducting any non-destructive test and interpreting results of ultrasonic, dye penetrant, x-rays, or magnetic particle tests.

Task Excludes:
- Visual inspection of welds covered in Task #37.

Prerequisite Tasks: None

Personnel That May Complete This Task

Individuals Certified as NDT Level II (although individuals are certified as Level II Technicians, they must also be qualified in this task)

Application of the Four-Part Test for Covered Task

This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification

Complexity: 2	Criticality: 3	Re-qualification Frequency: (Consistent with API 1104) 3 Years

Method of Evaluations

Initial: ASNT TC1A -- Level II Radiographic Testing or Level II Ultrasonic Testing or Level II Ultrasonic Testing Limited or Level II Magnetic Particle Testing or Level II Penetrant Testing AS APPLICABLE

Refresher: Same as initial

Internal Pass/Fail Criteria: 80%

Abnormal Operating Conditions

Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☒ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Hot Tapping Larger than 3"/Stoppling	Task ID# 39
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	

Task Description:
- Hot taps and stoppling operations that are larger than 3".

Task Excludes:
- Hot Taps smaller than 3" - covered in task 41

Prerequisite Tasks: None

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	3	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo PLOQ39 NCCER -- PMT written assessment, or PV406, PV408, PV409, PV409-1, or Module 62304, 62306, 66102 OQSG -- CT36 TDWilliamson MEA -- KNT/PEF1426
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Measuring Wall Thickness	Task ID#	40
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.579, 195.585		

Task Description:
This task is associated with determining wall thickness in a corrosion control program. This task may include:

- Using a pit gauge
- Using/calibrating ultrasonic tester
- Measuring corroded areas (internal or external)
- Inspecting internal pipe surface
- Identify wall thickness listed on the alignment sheets
- Recognize conditions that require reporting/repair

Task Excludes:

- Pipe strength analysis and/or other engineering evaluations conducted off-site. However, activities to obtain pit depth or wall thickness measurements are covered tasks.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Multiskill Technicians	Field Supervisors	Terminal Mechanics
Pipeliners	Contractors	Terminal Supervisors
Corrosion Techs	Inspectors	Terminal Superintendents
Tech Leaders	Engineering Techs	Terminal Operating Techs
Welders	Terminal Operators	Working Foremen

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 Years

Method of Evaluations	
Initial:	EMPCo -- PLOQ40 NCCER -- CPFT1I, CPFT1M written assessments, or PV081, PV082, PV083, PV120, or Module 61104, 61110, 66102 OQSG -- CT07, CT13 NACE -- CP1 MEA -- KNT/PEF0405, 0406
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Repairing/Replacing Pipelines	Task ID# 41
	Covered Task: ☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195.579, 195.581, 195.585, 192.309

Task Description:
This task may include working with various clamps, composite sleeves, wraps, hot taps, stopples, etc. to repair or replace a pipeline.

- Installing mechanical clamps and mechanical sleeves
- Installing composite sleeves (other than Clock Spring composite sleeves)
- Pipe or pipeline component/appurtenance replacement/tie-ins
- Hot tapping smaller than 3" on pipelines or tanks
- Repairing/Installing support structures

Task Excludes:

- Inspect exposed pipe - Task 23
- Hot tapping larger than 3"
- Installation of composite sleeves according to Clock Spring process, Task 32

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors	Tech Leaders	Terminal Superintendents
Welders	Field Supervisors	Terminal Operating Techs
Inspectors	Terminal Operators	Working Foremen
Pipeliners	Terminal Mechanics	
Multiskill Techs	Terminal Supervisors	

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	EMPCo -- PLOQ41 NCCER -- PMT written assessment, or PV401, PV402, PV403, PV404, PV405, PV406, PV407, PV409, PV409-1, or Module 62304, 62306, 66102 OQSG -- CT36 MEA -- KNT/PEF1426, 1432, 3605
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☒ Yes	☐ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☒ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Joining Plastic Pipe	Task ID#	42
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.8, 192.283, 192.285		

Task Description:

- This task may include bonding and assembling of plastic pipe. This task covers the selection of the appropriate pipe for specific applications and the proper bonding of that pipe following manufacturer's recommendations.

Task Excludes:

- Testing pipe and bond strength, certification of bonding procedures and determination of compatibility for service and product to be handled.

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors	Multiskill Techs	
Inspectors	Tech Leaders	
Pipeliners		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	1	Criticality:	2	Re-qualification Frequency: (Consistent with 192.283)	3 years

Method of Evaluations	
Initial:	This is not performed on EMPCo facilities
Refresher:	Same as initial
Internal Pass/Fail Criteria:	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☐ Yes	☒ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☐ Yes	☒ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☐ Yes	☒ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☐ Yes	☒ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Cathodic Protection Inspection on Underwater Facilities	Task ID#	51
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Prepare and calibrate test equipment
- Take and record cathodic protection readings

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT01U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Prevent External Corrosion on Underwater Pipelines	Task ID#	52
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Inspection of Existing Coatings
- Perform Surface Preparation
- Repair Coatings and Applications

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT02U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Measure Wall Thickness on Underwater Pipe	Task ID#	53
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Prepare and Calibrate Test Equipment
- Measure Wall Thickness with Ultrasonic Testing Methods
- Measure pit depth and pit diameter with pit gauge
- Collect RSTRENG Data

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT03U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Conduct Underwater Cathodic Protection Remediation	Task ID#	54
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Install galvanic anodes on submerged pipeline or facilities

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT04U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Conduct Temporary Marking of Underwater Pipelines	Task ID#	55
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Locate Pipeline
- Determine Pipeline Depth
- Install Temporary Pipeline Marker

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT05U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☒ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Conduct Underwater Valve Inspection, Maintenance and Repair	Task ID#	56
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Identify Valve Types and Components
- Conduct Visual Inspection of Valve and Flanges
- Repair Valve as Instructed

Task Excludes:

- Manually Operate Valve on Underwater Pipeline Assembly (Task 62)

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT06U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Movement of In-Service Underwater Pipeline	Task ID#	57
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Move In-service Pipeline
- Conduct Inspection of Pipeline for Secondary Stresses, Physical Damage and Coating Damage

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT07U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Abandoning, Safe Disconnect, Purging and Sealing of Underwater Pipelines	Task ID#	58
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Purge Pipeline
- Safely Disconnect Pipeline
- Seal Disconnected Portion of Pipeline
- Bury Disconnected Portion of Pipeline

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT08U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Installation, Replacement or Repair of Support Structures on Underwater Components	Task ID#	59
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Replace or Repair support Structures on Existing Underwater Components
- Install Additional Underwater Support Structure Elements to Existing Structure

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT09U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Inspection of Underwater Pipeline Facilities	Task ID#	60
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Conduct General Pipeline Inspection
- Conduct Inspection of Buried Pipe when Exposed
- Conduct Inspection of Pipeline Crossings
- Conduct Inspection of Flanged Tie-ins
- Conduct Inspection of Repairs
- Inspect and Identify Support Structures

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT10U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Perform Underwater Pipeline Repair Activities	Task ID#	61
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Excavate Pipeline
- Install Mechanical Split Sleeved repair clamp
- Perform Basic Cutting Operations
- Install Mechanical Couplings
- Install Spool Piece
- Perform Welding Operations

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT11U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Operation of an Underwater Assembly	Task ID#	62
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Manually Operate Valve on Underwater Pipeline Assembly

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT12U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions			
Component Failure:	☒ Yes ☐ No	Fire/Explosion:	☒ Yes ☐ No
Activation of Safety Device:	☐ Yes ☒ No	Physical System Damage:	☒ Yes ☐ No
Flow Rate Deviation	☐ Yes ☒ No	Abnormal Facility Condition:	☒ Yes ☐ No
Unexplained Status Change:	☐ Yes ☒ No	Unexpected Hazardous Liquids:	☒ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☒ No	Inadequate Odorization/Odor Report	☐ Yes ☒ No

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COVERED TASK ANALYSIS

Task:	Perform Underwater Pigging Activities	Task ID#	63
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Launch Pig(s)
- Receive Pig(s)

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT13U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Perform Underwater Flange Mating Procedures	Task ID#	64
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Perform Flange Assembly General Procedures (Make-up)
- Perform Flange Disassembly General Procedures (Break-Down)

Task Excludes:

•

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT14U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☐ Yes	☒ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☐ Yes	☒ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☒ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

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COVERED TASK ANALYSIS

Task:	Perform an Underwater Mechanical Hot Tap	Task ID#	65
		Covered Task:	☒ Yes ☐ No
Regulatory Reference(s):	195.557, 195.559, 195.561, 195.563, 195.567, 195,579, 195.581, 195.585		

Task Description:

- Remove Coating
- Conduct Pipe Quality Checks
- Install Hot Tap Fitting
- Operate Tool and Remove Coupon
- Repair Coating and Bury Pipe as Required

Task Excludes:

-

Prerequisite Tasks: None

Personnel That May Complete This Task		
Contractors		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification					
Complexity:	2	Criticality:	2	Re-qualification Frequency:	3 years

Method of Evaluations	
Initial:	OQSG CT15U
Refresher:	Same as initial
Internal Pass/Fail Criteria: 80%	

Abnormal Operating Conditions					
Component Failure:	☒ Yes	☐ No	Fire/Explosion:	☒ Yes	☐ No
Activation of Safety Device:	☒ Yes	☐ No	Physical System Damage:	☒ Yes	☐ No
Flow Rate Deviation	☒ Yes	☐ No	Abnormal Facility Condition:	☒ Yes	☐ No
Unexplained Status Change:	☐ Yes	☒ No	Unexpected Hazardous Liquids:	☒ Yes	☐ No
Communication, Power Interruption/Failure	☒ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☒ No

COVERED TASK ANALYSIS

Task: Abandoning or Deactivating Pipelines	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
Abandoning or deactivating pipelines as specified in *CFR 192.727* does not meet the definition of "an operations and maintenance task" and can not affect the operations or integrity of the pipeline.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Analyzing Tool Runs	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

This task is not performed on a pipeline facility, is not an operations or maintenance task and can not affect the operation or integrity of the pipeline. The actual tool run is a covered task and is covered, as needed, under other applicable covered tasks.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Close Interval Surveys	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is not required under CFR 195 or 192. Any operations or maintenance task associated with this task is covered, as needed, under other applicable tasks such as measuring pipe to soil.
Task Excludes:
•
Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Conducting Emergency Drills	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
Conducting emergency drills is not an operations and maintenance task, is not required under CFR 195 or CFR 192 and does not affect the operations or integrity of the pipeline.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Entering Confined Spaces	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:

Entering a confined space does not meet the definition in the plan as "an operations and maintenance task and will not affect the operation or integrity of the pipeline. Any operational or maintenance tasks performed before or during confined space entry will be addressed, as needed, in other applicable covered tasks.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Controlling Energy, Lockout and Tagout	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:

This task is not required under CFR 195 or CFR 192 and any operations required to control energy are included in other covered tasks, therefore it is not addressed separately as a covered task. Individuals will be qualified, as needed, under other applicable tasks. See covered task opening, closing and monitoring valves.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Converting to Service	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

Converting to service is considered a study task and not an operations or maintenance task. Furthermore there are other standards that regulate this task. The operations required to convert the service of the line, such as pressure testing, purging HVLs and products are covered tasks. Individuals performing these tasks will be qualified under the applicable task.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Customer Notifications	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is not performed on a pipeline facility, is not an operations or maintenance task and cannot affect the operation or integrity of the pipeline. Furthermore this task is associated with distribution lines and is not applicable to EMPCo's operations.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Ditching	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task does not meet the definition as specified in EMPCo's OQ Program of an "operations and maintenance task," and it can not affect the operation or integrity of the pipeline.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Evacuating the Public	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
Evacuating the public is not performed on a pipeline facility, is not an operations or maintenance task and does not affect the operations or integrity of the pipeline.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Excess Flow Valve Notification	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is not performed on a pipeline facility, is not an operations or maintenance task and cannot affect the operation or integrity of the pipeline. Furthermore this task is associated with distribution lines (single resident lines) and is not applicable to EMPCo's operations.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Underwater Inspection and Reburial of pipelines in the Gulf of Mexico and its Inlets	Task ID# N/A
		Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):		

Task Description:

The inspections stipulated under 49 CFR 195 and 49 CFR 192 were required prior to November 16, 1992. The reburial of pipelines that are discovered by the operator to be exposed on the seabed or constitute a hazard to navigation would be accomplished under other covered tasks -- locating pipelines, inspecting underwater pipelines, and moving pipelines.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Inspecting Firefighting Equipment	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task includes fixed systems and is not performed on a pipeline facility, is not an operations or maintenance task and will not affect the operation or integrity of the pipeline, therefore it is not a covered task. These inspections are completed to comply with applicable OSHA standards.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Inspecting New Pipelines	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:
This task does not meet the definition specified in EMPCo's OQ Program as an "operations or maintenance task."

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Launching, receiving, locating scrapers	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

This task is not required under CFR 195 or CFR 192 and any operations required to launch, receive and locate scrapers are included in other covered tasks, therefore it is not addressed separately as a covered task. Individuals will be qualified, as needed, under other applicable tasks. See covered task opening, closing and monitoring valves.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Performing/Changing Class Location Surveys	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is not an operations and maintenance task and it can not affect the operations or integrity of the pipeline.
Task Excludes:
•
Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Mowing Right-of-Way	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

Mowing the right-of-way is not required under CFR 195 or 192. The regulation requires that the right-of-way must be inspected. If mowers are performing inspection activities or placing line markers they must be qualified under Task #13 (Patrolling lines) and Task #14 (Placing/Maintaining Line Markers).

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Reviewing/Updating Operations/Maintenance and Emergency Procedures	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:

Reviewing and updating operations, maintenance and emergency procedures is an administrative task and is not performed on a pipeline facility and is not an operations or maintenance task.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Preventing Damage	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
Preventing damage does not meet the definition as specified in EMPCo's OQ plan as "an operations or maintenance task." Any operation or maintenance task associated with preventing damage is covered in other applicable tasks.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Taking and Analyzing Product Sample/Composition	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task can not affect the operation or integrity of the pipeline. Any operation and maintenance task that is required to perform this task is addressed, as needed, in other applicable covered tasks such as opening and closing valves.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Proving Meters	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

Proving meters is not required under CFR 195 or CFR 192. Any operational or maintenance tasks performed to prove meters will be addressed, as needed, in other applicable covered tasks (i.e. monitoring pipeline systems, opening and closing valves, etc.).

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Conducting Public Education Program	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task does not meet the definition as specified in EMPCo's OQ program as "performed on a pipeline facility," or "an operations or maintenance task."
Task Excludes:
•
Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Determination of relief devices capacity	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is a calculation and not performed on a pipeline facility, therefore it is not considered a covered task.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Reporting Accidents, Incidents, and Safety-Related Conditions	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task does not meet the definition specified in EMPCo's OQ Plan "performed on a pipeline facility" nor is it an operations and maintenance task therefore it is not a covered task. Recognizing a safety-related condition is covered under other tasks, (i.e. exposing a line, measuring wall thickness, patrolling lines and leakage surveys).

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Responding to a fire, explosion or leak	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description: This task does not meet the definition as specified in EMPCo's OQ program as "performed on a pipeline facility," or "an operations or maintenance task."
Task Excludes: •
Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task:	Reviewing risk-based alternative assessments	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:

This task is an assessment and does not meet the definition specified in EMPCo's OQ Plan as a task that is "performed on a pipeline facility," nor does it meet the definition specified in the plan of an "operations or maintenance task."

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Provide Security	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is not an operations or maintenance task as defined in EMPCo's Written Program.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task: Testing New Pipelines	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task does not meet the definition specified in EMPCo's OQ Program as an "operations or maintenance task." In addition, new construction is not covered under this rule, see "new construction task" in Premises and Definitions.
Task Excludes:
•
Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions			
Component Failure:	☐ Yes ☐ No	Fire/Explosion:	☐ Yes ☐ No
Activation of Safety Device:	☐ Yes ☐ No	Physical System Damage:	☐ Yes ☐ No
Flow Rate Deviation	☐ Yes ☐ No	Abnormal Facility Condition:	☐ Yes ☐ No
Unexplained Status Change:	☐ Yes ☐ No	Unexpected Hazardous Liquids:	☐ Yes ☐ No
Communication, Power Interruption/Failure	☐ Yes ☐ No	Inadequate Odorization/Odor Report	☐ Yes ☐ No

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COVERED TASK ANALYSIS

Task:	Measure clearance from existing pipe to underground structures	Task ID#	N/A
		Covered Task:	☐ Yes ☒ No
Regulatory Reference(s):			

Task Description:

This task is not performed on a pipeline facility, is not an operations or maintenance task. Furthermore this task is associated with construction.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☐ Yes	☒ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Uprating	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:
This task is a calculation so therefore does not meet the definition of an operations or maintenance task. Any operations or maintenance task associated with uprating is covered, as needed, under other applicable tasks such as pressure testing.

Task Excludes:
•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Welding New Pipelines	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

This task does not meet the definition specified in EMPCo's OQ Program as an "operations or maintenance task." In addition, new construction is not covered under this rule, see "new construction task" in Premises and Definitions. Consideration must be given when new lines are being tied into existing regulated systems to determine if that task meets the four-part test.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☐ Yes	☒ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☒ Yes	☐ No
This task can affect the operation or integrity of the pipeline	☒ Yes	☐ No

Frequency of Re-qualification			
Complexity:	Criticality:	Re-qualification Frequency:	years

Method of Evaluations
Initial:
Refresher:
Internal Pass/Fail Criteria:

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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COVERED TASK ANALYSIS

Task: Work on Geodesic Dome Roof	Task ID# N/A
	Covered Task: ☐ Yes ☒ No
Regulatory Reference(s):	

Task Description:

- Work performed on a geodesic dome roof is not considered a covered task because such work does not meet the four conditions specified by DOT's definition of a covered task. Geodesic dome roofs and related maintenance tasks are not required by DOT Part 195 regulations, nor are they regarded as affecting the operation or integrity of the tank.

Task Excludes:

•

Prerequisite Tasks:

Personnel That May Complete This Task		

Application of the Four-Part Test for Covered Task		
This task is performed on a pipeline facility	☒ Yes	☐ No
This is an operations and maintenance task	☒ Yes	☐ No
This task is performed as a requirement under 49 CFR 195 or 49 CFR 192	☐ Yes	☒ No
This task can affect the operation or integrity of the pipeline	☐ Yes	☒ No

Frequency of Requalification			
Complexity:	Criticality:	Requalification Frequency:	years

Method of Evaluations
Initial:
Refresher: Same as initial
Internal Pass/Fail Criteria: 80%

Abnormal Operating Conditions					
Component Failure:	☐ Yes	☐ No	Fire/Explosion:	☐ Yes	☐ No
Activation of Safety Device:	☐ Yes	☐ No	Physical System Damage:	☐ Yes	☐ No
Flow Rate Deviation	☐ Yes	☐ No	Abnormal Facility Condition:	☐ Yes	☐ No
Unexplained Status Change:	☐ Yes	☐ No	Unexpected Hazardous Liquids:	☐ Yes	☐ No
Communication, Power Interruption/Failure	☐ Yes	☐ No	Inadequate Odorization/Odor Report	☐ Yes	☐ No

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Appendix 3 Forms

Alternate Evaluation Method for Individuals 147
Acceptance Process for Evaluation Methods 149
Operator Qualification Covered Task Record 151

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Operator Qualification
Alternate Evaluation Method for Individuals

Name of Individual Being Evaluated:	
Task Name and Number:	
Name of Alternate Method:	
Vendor's Name (if applicable):	

Describe the steps used to provide the individual with the knowledge and skills necessary to perform the task:
1.
2.
3.
4.
5.

Describe the steps used to provide the individual with the ability to respond to abnormal operating conditions that could occur while performing the covered task:
1.
2.
3.
4.
5.

Alternate Evaluation Method Utilized:

☐	Written test	Individual's test score		
☐	Task performance verification	Satisfactory performance	☐ Yes	☐ No

Evaluator's Name Evaluator's Signature Date

Send completed form to the Training Advisor

To be completed by the Training Advisor:

☐ Alternate Evaluation Method is acceptable and the individual is qualified.
☐ Alternate Evaluation Method is not acceptable and the individual is not qualified.
Reason(s):

Training Advisor's Name Training Advisor 's Signature Date

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Operator Qualification
Acceptance Process for Evaluation Methods

This process was developed to ensure a consistent review of contractor, vendor, affiliate and third party OQ evaluation methods/programs.

This review is being conducted on (select one):
☐ Contractor Program
☐ Vendor Program
☐ Third Party/Affiliate
Name of evaluation method/program:

PROCESS STEPS	YES	NO	NA
Has the list of covered tasks been cross-referenced with EMPCo's?			
Is there an evaluation method for each covered task performed for EMPCo? (See list below.)			
Are the initial and subsequent qualification methods consistent or exceed the requirements within EMPCo's Written Program?			
Are the quality and content of the evaluation methods acceptable to EMPCo (does it address all of the elements identified in EMPCo's covered tasks)?			
Are the pass/fail criteria acceptable to EMPCo?			
Are written tools used to ensure consistency for performance based evaluations acceptable to EMPCo?			
Is the program/evaluation method available for periodic audit?			

This evaluation method (☐ applies ☐ does not apply) to the following covered tasks:

Task	Task	Task	Task
Task	Task	Task	Task
Task	Task	Task	Task

Reason for "NO" answers:

Evaluation Method Determination:	☐ Acceptable
	☐ Unacceptable

Program Evaluator's Name Program Evaluator's Signature Date

Note: Any individual that utilizes this evaluation method must conform to EMPCo's Written Program, including re-qualification frequencies, post-incident re-qualification process, span-of-control parameters and provide their records through ISNetworld.

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Operator Qualification Covered Task Record

Work Location:	Verification Date:
Work Description:	

Operator qualifications of contractor personnel preparing to work on EMPCo's DOT-regulated pipelines and terminals must be verified before the contractor begins the work. Identify the OQ covered task number(s) to be performed in the appropriate column, followed by the (printed) name of the qualified and non-qualified individuals. Indicate whether the qualified individual is an EMPCo employee or contractor. Place an "X" in the box adjacent the name of the qualified individual responsible for the direct observation of non-qualified individuals.

EMPCo employees performing a task on a DOT-regulated pipeline that requires a work permit need to be listed in the appropriate column as the qualified or non-qualified individuals. The Operator Qualification Covered Task Record does not have to be completed for qualified individuals performing routine, day-to-day OQ covered tasks that do not require issuance of a work permit, e.g. locating a pipeline in response to a one-call notification, or operating valves to align tanks for a batch change.

A new Operator Qualification Covered Task Record must be completed when a change in personnel occurs, either the qualified or non-qualified individuals or the qualified individual responsible for span of control over non-qualified individuals. The Operator Qualification Covered Task Record must be retained for at least five years.

The table on the following page provides a list of the EMPCo OQ Covered Tasks and the Span of Control Limits regarding the maximum number of non-qualified individuals who may be covered by a qualified individual. The table is designed to serve as a quick reference and does not have to be retained with this page.

OQ Covered Task Number	Qualified Individuals (Please print name - no initials)	EMPCo	Contractor	Responsible for Span of Control	Non-Qualified Individuals Working Under Span of Control (Please print name - no initials)
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
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		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	
		☐	☐	☐	

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EMPCo Operator Qualification Covered Task List

OQ Covered Task Number	Span of Control Limit	Description	OQ Covered Task Number	Span of Control Limit	Description
1	5	Inspect, test & calibrate control devices	30	5	Inspecting, testing and replacing overpressure/overfill control devices
2	5	Starting & stopping pumps/compressors locally	31	5	Routine Monthly Breakout Tank Inspections
3	5	Repairing breakout storage tanks	32	0	Clockspring Repairs
4	5	Opening, closing, monitoring valves; isolating system	33	0	Excavating near facilities and Backfilling
7	5	Installing/Maintaining Field SCADA equipment	35	5	In-Service Inspection of Breakout Storage Tanks
8	5	Purging, flaring HVL's and natural gas	36	5	Moving pipelines
9	5	Displacing crude and products	37	0	Welding or welding repairs on existing lines, includes weld inspection
10	5	Odorizing	38	0	Performing non-destructive tests
11	5	Launching and receiving in-line inspection tools	39	0	Hot Tapping Larger than 3" Stoppling
12	5	Pressure Testing	40	5	Determining Wall Thickness
13	5	Patrolling lines - air, vehicle, or foot	41	5	Repairing and replacing pipelines
14	5	Line locating, placing/maintaining line markers	51	0	Cathodic Protection Inspection of Underwater Facilities
15	5	Leakage surveys	52	0	Prevent External Corrosion on Underwater Pipelines
16	5	Inspecting Navigable Waterway Crossings	53	0	Measure Wall Thickness on Underwater Pipe
17	5	Measuring structure to soil potentials	54	0	Conduct Underwater Cathodic Protection Remediation
18	5	Determining shorted casing	55	0	Conduct Temporary Marking of Underwater Pipelines
19	5	Inspecting/Monitoring shorted casings	56	0	Conduct Underwater Valve Inspection, Maintenance and Repair
20	5	Repairing casings	57	0	Movement of In-Service Underwater Pipeline
21	5	Reading rectifiers	58	0	Abandoning , Safe Disconnect, Purging and Sealing of Underwater Pipelines
22	5	Adjusting, installing, repairing rectifiers & installing and repairing groundbeds	59	0	Installation, Replacement or Repair of Support Structures on Underwater Components
23	5	Inspecting exposed pipe and performing atmospheric surveys	60	0	Inspection of Underwater Pipeline Facilities
24	5	Installing, replacing, repairing anodes, test leads and bonds	61	0	Perform Underwater Pipeline Repair Activities
25	5	Installing and removing coupons	62	0	Operation of an Underwater Assembly
26	5	HUB Operations	63	0	Perform Underwater Pigging Activities
27	5	Coating or recoating pipe	64	0	Perform Underwater Flange Mating Procedures
28	5	Inspecting, and routine maintenance of valves	65	0	Perform Underwater Mechanical Hot Tap
29	5	Repairing and Maintaining Valves			

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Appendix 4 Frequently Asked Questions (FAQs)

Question:

How did you get assigned the OQ tests that are listed in the computer based training application?

Answer:

There is a form called an Individual Inventory that lists all of EMPCo's covered tasks. Each Field Level Supervisor completed a form for each employee that completes Operations and Maintenance tasks. The Supervisor identified the tasks that each employee may be expected to perform after October 28, 2002. The form was completed then forwarded to the Operations Integrity Department (OID). OID entered the data into the computer based training application.

Question:

What should you do if you think your list of assigned covered tasks is incorrect?

Answer:

You should discuss this with your Supervisor. If changes need to be made, your Supervisor must approve those changes and send them to Stuart Buchanan or the Local FET/FRS.

Question:

Why do some individuals with the same job title have different OQ tasks assigned?

Answer:

OQ is based on an individual basis and not job title. Since our workforce is so diverse, OQ tasks are assigned by expectations of each individual and efficiencies that have been created throughout our operating facilities.

Question:

Why don't OQ qualifications count towards progression in multiskill?

Answer:

OQ and multiskill are two separate processes. OQ is used to identify the minimum skill and knowledge individuals need to complete a covered task to meet a regulatory requirement. The multiskill progression and promotion process is used for employee advancement and is based on demonstrated skills. Therefore, a written test in OQ does not constitute demonstrated skills in multiskill.

Question:

Why aren't there any training materials available before you take the OQ test?

Answer:

OQ was developed to test the skills and knowledge of our workforce on activities they currently are performing and therefore should possess the skills and knowledge without additional training. If an

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individual does not pass the qualification test, that individual should discuss the reason with their Supervisor and identify other training opportunities.

Question:

Why doesn't the computer-based training application tell you when you get a question right or wrong?

Answer:

The functionality of the computer-based training application that indicates a correct or incorrect answer has been disabled. To attempt to protect the integrity of the tests, we are not providing that information to individuals while they are taking the test.

Question:

Why are the evaluations timed?

Answer:

To attempt to protect the integrity of the tests, we want to test the current knowledge and skills of employees without utilizing the help from others or referencing written materials.

Question:

What will happen if a Supervisor learns that individuals are sharing answers with their co-workers on the OQ evaluations, which aids an individual in their attempt to pass an OQ evaluation?

Answer:

Individuals will be subject to disciplinary action.

Question:

What should you do if you are taking an OQ test, and the test is based on equipment that you do not have or use at your location?

Answer:

Document, which test you are in, and report the discrepancy to the subject matter expert identified as our Company OQ Subject Matter Expert for that covered task. The experts are listed in the attached document, or you find the list in EMPCo's OQ Guidance Document (not yet issued) or contact Michele Snider.

Question:

What if an individual cannot pass a qualification method?

Answer:

If an individual cannot pass a qualification method, he/she will not be permitted to perform that task after October 28, 2002 unless at the direction of a qualified individual. The individual may be provided with additional training material or on-the-job training opportunities to provide him/her with the knowledge and skills necessary to perform the task. The individual will be permitted to retake the qualification method as many times as the local Supervisor deems appropriate.

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Question:

What if an individual needs to be reevaluated in the middle of a shift?

Answer:

If the qualification method is contained within Mockingbird, the individual can be reevaluated. If the qualification method is not contained in Mockingbird, the local Supervisor will determine what actions to take.

Question:

What do you do with individuals that may have caused an incident because of their performance?

Answer:

Management has the discretion to allow an individual to continue to perform covered tasks until it can be determined if there is reason to believe that an employee is no longer able to perform a covered task.

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Keener, Blaine (PHMSA)

From: Hess, John (PHMSA)
Sent: Friday, July 08, 2011 11:37 AM
To: Davis, Gerald (PHMSA); Finch, Thomas (PHMSA); Hill, Damon (PHMSA); Hoidal, Chris (PHMSA); Katchmar, Peter (PHMSA); Petronis, Michael (PHMSA); PHMSA PHP-5 Response; PHMSA PHP500 Response; PHMSA Pipeline Failure Exec Update
Cc: Nanney, Steve (PHMSA)
Subject: FW: Draft Closing

Good morning.

The remaining PHMSA inspector will leave the incident site today. Another PHMSA inspector will be in Billings, MT on Monday, July 11, 2011, to continue PHMSA's investigation, monitor operations following PHMSA's Corrective Action Order to ExxonMobil pipeline, and support of the Unified Command.

This will be the last scheduled update. Important information will be passed as it is received.

John C. Hess
Emergency Support & Security
202-366-4031 cell 202-306-3185

Keener, Blaine (PHMSA)

From: Hess, John (PHMSA)
Sent: Thursday, July 07, 2011 7:44 PM
To: Davis, Gerald (PHMSA); Finch, Thomas (PHMSA); Hill, Damon (PHMSA); Hoidal, Chris (PHMSA); Katchmar, Peter (PHMSA); Petronis, Michael (PHMSA); PHMSA PHP-5 Response; PHMSA PHP500 Response; PHMSA Pipeline Failure Exec Update
Subject: Update: ExxonMobil Crude Oil Spill Yelllowstone River

The PHMSA Western Region Director met with Yellowstone County Officials today. He will return to the Region Office tomorrow. One PHMSA Inspector remains on scene, monitoring operations and supporting the Unified Command.

The next update will be issued after 11:00 a.m. tomorrow. Important information will be passed as it is received.

John C. Hess
Emergency Support & Security
202-366-4031 cell 202-306-3185

Keener, Blaine (PHMSA)

From: Hess, John (PHMSA)
Sent: Thursday, July 07, 2011 11:35 AM
To: Davis, Gerald (PHMSA); Finch, Thomas (PHMSA); Hill, Damon (PHMSA); Hoidal, Chris (PHMSA); Katchmar, Peter (PHMSA); Petronis, Michael (PHMSA); PHMSA PHP-5 Response; PHMSA PHP500 Response; PHMSA Pipeline Failure Exec Update
Subject: Update: Crude Oil Spill ExxonMobil Pipeline Yellowstone River near Laurel, MT
Attachments: Info Bull ExxMobil MT 09 (07-07-11).pdf

PHMSA's Western Region Director (RD) and an inspector are on site. PHMSA's RD attended a community meeting in Laurel concerning the spill. He reported there were more than 130 citizens at the meeting.

PHMSA staff visited the South Bank of the Yellowstone River, near the Rt. 212 bridge with a Laurel City Official. PHMSA continues reach out to local officials, monitor operations at the site, and support the Unified Command.

Our next scheduled update will be after 6:00 p.m. today. Important information will be passed as it is received.

John C. Hess
Emergency Support & Security
202-366-4031 cell 202-306-3185

Keener, Blaine (PHMSA)

From: Finch, Thomas (PHMSA)
Sent: Thursday, July 07, 2011 9:41 AM
To: Keener, Blaine (PHMSA)
Cc: Stahoviak, Jeff (PHMSA)
Subject: FW: I pushed back by flight

FYI- Mike P. is back east and will be back next Monday.

From: Petronis, Michael (PHMSA)
Sent: Thursday, July 07, 2011 7:34 AM
To: Finch, Thomas (PHMSA)
Subject: RE: I pushed back by flight

Sorry I lost you on the phone Tom - looks like the battery was low - it is charging in the car right now. I will work this evening to make sure you've got all the appropriate emails. I believe I may have the name of the person in my notes at home that Kurt said he was in contact with at the Corps. I can provide that (if I in fact have it) on Monday.

From: Finch, Thomas (PHMSA)
Sent: Thu 7/7/2011 7:29 AM
To: Hoidal, Chris (PHMSA)
Cc: Petronis, Michael (PHMSA)
Subject: RE: I pushed back by flight

I talked to Mike P. Per the PIM it was Kurt M. of the City of Laurel that was going to contact the Corps of Engineers. Per Mike Kurt did contact the Corps but did not get much of a response from the Corps of Engineers. Mike said Kurt did not pursue it much further.

Mike did not do daily reports in May 2011. He did take a lot of pictures and sent some emails.

Thanks.

Tom

From: Hoidal, Chris (PHMSA)
Sent: Thursday, July 07, 2011 5:57 AM
To: Bonnett, Kristi (PHMSA); Larson, Terrence (PHMSA); Larson, Terrence (PHMSA); Finch, Thomas (PHMSA); Stahoviak, Jeff (PHMSA)
Subject: I pushed back by flight

I will be coming back on the 522 pm flight so I can attend a County of Yellowstone briefing. I will be in during the morning.

Jeff should work with Finch to get all information related to Exxon Mobil spill.

Keener, Blaine (PHMSA)

From: laura.k.sleevi@exxonmobil.com
Sent: Saturday, July 02, 2011 11:41 AM
To: Finch, Thomas (PHMSA); larry.e.hawthorne@exxonmobil.com
Cc: gary.w.hartmann@exxonmobil.com; Petronis, Michael (PHMSA); thad.massengale@exxonmobil.com; Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA); Katchmar, Peter (PHMSA); Jason Montgomery
Subject: Re: Fw: NRC#981503: Pipeline - Laurel, MT (169 miles northwest of Helena, MT), material release

Tom, right now, call Jeb Montgomery. 4066705069. Doc and I are en route now.

Thanks, Laura
office: 509.534.8132 ext. 2 // cell: 562.233.5113

----- Original Message -----
From: [Thomas.Finch@dot.gov]
Sent: 07/02/2011 10:13 AM AST
To: Larry Hawthorne
Cc: Laura Sleevi; Gary Hartmann; <michael.petronis@dot.gov>; Thad Massengale; <gerald.davis@dot.gov>; <chris.hoidal@dot.gov>; <Peter.Katchmar@dot.gov>
Subject: RE: Fw: NRC#981503: Pipeline - Laurel, MT (169 miles northwest of Helena, MT), material release

"Doc",

I just called and left you a voicemail concerning contact numbers for your personnel on site.

Our Jerry Davis should be onsite in about 4 hours. His cell phone number is 202-510-6147.

Please provide us with cell phone contact numbers for your personnel at the site.

Thanks.
Tom Finch

-----Original Message-----
From: larry.e.hawthorne@exxonmobil.com [mailto:larry.e.hawthorne@exxonmobil.com]
Sent: Saturday, July 02, 2011 2:46 AM
To: Finch, Thomas (PHMSA)
Cc: laura.k.sleevi@exxonmobil.com; gary.w.hartmann@exxonmobil.com; Petronis, Michael (PHMSA); thad.massengale@exxonmobil.com
Subject: Re: Fw: NRC#981503: Pipeline - Laurel, MT (169 miles northwest of Helena, MT), material release

Tom, the 12 Crude Oil pipeline was shut down when our Operation Control Center notice a pressure drop on the line about 23:40 -July 1.....
Our controller also later received a call from the Laurel Fire Dept of a crude odor and we response by sending our local personnel to the site.
The line was shut down, valves on both side of the River shut in, and other valves closed on the line.

We don't have an estimate of barrels out at this time but we are working on an estimate.

Our Billing Refinery Emergency Response s team was notified and has been sent to the site along with our local Emergency Responders.

There is heavy flooding at the site. Safety of the people is being address.

regards-
Larry "Doc" Hawthorne-
Pipeline Safety Compliance Advisor
(SHE)-Safety,Health,&Environmental Department
Office 903-654-5345-(CELL)903-879-0313-
FAX 903-654-5302
email: larry.e.hawthorne@exxonmobil.com
1604 South 15th St.. Corsicana, Texas 75110

<Thomas.Finch@dot.gov>

07/02/2011 02:50 AM

To <larry.e.hawthorne@exxonmobil.com>

cc <laura.k.sleevi@exxonmobil.com>, <Steve.Nanney@dot.gov>, <PHMSAPHP500Response@dot.gov>

Subject Fw: NRC#981503: Pipeline - Laurel, MT (169 miles northwest of Helena, MT), material release

Larry"Doc" and Laura,
Please provide us with an update concerning this report.
Thanks.
Tom Finch
Thomas.finch@dot.gov
303-807-7200.

From: CMC-01 (OST)
Sent: Saturday, July 02, 2011 02:33 AM
To: PHMSA PHP80 Response; PHMSA PHP500 WESTERN
Subject: NRC#981503: Pipeline - Laurel, MT (169 miles northwest of Helena, MT), material release

This report is forwarded for your situational awareness. CMC 6-1863

NATIONAL RESPONSE CENTER 1-800-424-8802

GOVERNMENT USE ONLYGOVERNMENT USE ONLY***

Information released to a third party shall comply with any

applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 981503

INCIDENT DESCRIPTION

*Report taken by: MST3 RUDOLPH GANTHER at 02:19 on 02-JUL-11

Incident Type: PIPELINE

Incident Cause: FLOOD

Affected Area: YELLOWSTONE RIVER

Incident was discovered on 02-JUL-11 at 00:45 local incident time.

Affected Medium: WATER YELLOW STONE RIVER

REPORTING PARTY

Name: LARRY HAWTHORNE

Organization: EXXON MOBIL PIPELINE

Address: 800 BELL ST.

HOUSTON, TX

EXXON MOBIL PIPELINE reported for the responsible party.

PRIMARY Phone: (903)8790313

Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: LARRY HAWTHORNE

Organization: EXXON MOBIL PIPELINE

Address: 800 BELL ST.

HOUSTON, TX

PRIMARY Phone: (903)8790313

INCIDENT LOCATION

YELLOWSTONE RIVER County: YELLOWSTONE

City: LAUREL State: MT

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE

Also Known As:

Qty Released: 0 UNKNOWN AMOUNT Qty in Water: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

CALLER IS REPORTING THAT A PIPELINE HAS BROKEN IN THE RIVER

RELEASING CRUDE OIL. THE DAMAGE WAS CAUSED BY RIVER FLOODING.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION

DOT Regulated: YES

Pipeline Above/Below Ground: BELOW

Exposed or Under Water: YES

Pipeline Covered: YES

---WATER INFORMATION---

Body of Water: YELLOWSTONE RIVER

Tributary of:

Nearest River Mile Marker:

Water Supply Contaminated: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:

FATALITIES: NO Empl/Crew: Passenger: Occupant:

EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure
N			
Air:			
N			Major
Road:			Artery:N
N			
Waterway:			
N			
Track:			

Environmental Impact: UNKNOWN

Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

VALVES WERE CLOSED TO STOP THE FLOW OF THE PIPELINE.

Release Secured: YES

Release Rate:

Estimated Release Duration:

WEATHER

Weather: RAINY, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE

State/Local: FD

State/Local On Scene: FD

State Agency Number: NONE

NOTIFICATIONS BY NRC

DHS NOC (NOC)

02-JUL-11 02:29 (202)2828114

USCG ICC (ICC ONI)

02-JUL-11 02:29 (301)6693363

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)

02-JUL-11 02:29 (202)3661863

U.S. EPA VIII (MAIN OFFICE)

(303)2931788

FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)

02-JUL-11 02:29 (800)6347084

INFO ANALYSIS & INFRA PROTECTION (MAIN OFFICE)

02-JUL-11 02:29

MT DEPT OF ENVIRONMENTAL QUALITY (MAIN OFFICE)

02-JUL-11 02:29 (406)4440379

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)

02-JUL-11 02:29 (202)2829201

NATIONAL INFRASTRUCTURE COORD CTR (INFRASTRUCTURE PROTECTION)

02-JUL-11 02:29 (202)2829201

NOAA RPTS FOR MT (MAIN OFFICE)

02-JUL-11 02:29 (206)5264911

PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))

02-JUL-11 02:29 (202)3660568

DOI/OEPC DENVER (MAIN OFFICE)

02-JUL-11 02:29 (303)4452500

ADDITIONAL INFORMATION

NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT #981503 ***

Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

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Keener, Blaine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Thursday, June 02, 2011 12:28 PM
To: Finch, Thomas (PHMSA); Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Subject: FW: IMG00344-20110601-1609.jpg
Attachments: IMG00344-20110601-1609.jpg

Riverbank erosion

From: Petronis, Michael (PHMSA)
Sent: Thu 6/2/2011 8:47 AM
To: Petronis, Michael (PHMSA)
Subject: IMG00344-20110601-1609.jpg



To: Finch, Thomas (PHMSA); Larson, Terrance (PHMSA); Nguyen, Huy (PHMSA)

Keener, Blaine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Thursday, June 02, 2011 1:05 PM
To: Finch, Thomas (PHMSA); Larson, Terrence (PHMSA); Nguyen, Huy (PHMSA)
Subject: FW: IMG00348-20110601-1615.jpg
Attachments: IMG00348-20110601-1615.jpg

Finger is pointing to crossing location on opposite bank

From: Petronis, Michael (PHMSA)
Sent: Thu 6/2/2011 8:37 AM
To: Petronis, Michael (PHMSA)
Subject: IMG00348-20110601-1615.jpg



Keener, Blaine (PHMSA)

From: Kurt Markegard [kmarkegard@laurel.mt.gov]
Sent: Wednesday, June 01, 2011 2:42 PM
To: Finch, Thomas (PHMSA)
Cc: dhabermann@mt.gov; City Mayor; hjensen@laurel.mt.gov
Subject: RE: Boat Ramp in Laurel Montana after Flood Event May 25,26, 2011
Attachments: IMG_20110531_145428.jpg; IMG_20110525_130748.jpg

From: Kurt Markegard
Sent: Wednesday, June 01, 2011 12:41 PM
To: 'Thomas.Finch@dot.gov'
Cc: 'dhabermann@mt.gov'; City Mayor; 'hjensen@laurel.mt.gov'
Subject: Boat Ramp in Laurel Montana after Flood Event May 25,26, 2011

Tom,

The Yellowstone River had high flows due to record setting rains in the Yellowstone basin last week. This caused more damage to the boat ramp and I would assume a significant amount of riverbed scour.

I was contacted by someone at Exxon during the event and was asked if I had any concerns about their pipeline. I told them that I was not concerned with that as I was trying at the time, to keep the Yellowstone River from flooding the City of Laurel's Water Treatment Plant on the north bank across from Riverside park. I sent that person a email with a picture of the River showing them the flows. I told them that maybe they should have someone from their company look for themselves.

I thought I would send you the photo as well and a picture of the boat ramp after it was safe to enter to get pictures.

Thank you,

Kurt Markegard
Public Works Director
City of Laurel, MT 59044
(406)628-4796 office
(406)860-5785 cell

Weaver, Antoine (PHMSA)

From: Finch, Thomas (PHMSA)
Sent: Wednesday, June 01, 2011 3:52 PM
To: 'Kurt Markegard'
Cc: Petronis, Michael (PHMSA); Larson, Terrence (PHMSA)
Subject: FW: Montana Flooding Update from the Western Region

Kurt,

This is a previous report from our inspectors. As you know our Mike Petronis is in Billings.

ExxonMobil – They are conducting patrols and have not found any significant issues other than some erosion near/across the pipeline right of way. The Yellowstone River crossing depth was surveyed last fall and is quite deep and should be adequate as long as the riverbank does not substantially erode and cause flooding in Riverside Park near Laurel.

Williston Basin reported that they elected to shut in their shallow pipeline crossing of the Yellowstone near Laurel due to the high river flows. They are able to run all capacity through the new Yellowstone River crossing that was bored under the river a couple of years ago. WBI district personnel are patrolling their lines as necessary but have not found any significant areas of concern.

If you have questions or desire additional information please contact us. Thank you for your efforts to protect your City of Laurel and I wish you the best.

Thanks for your information and photos.

Tom

Thomas Finch
CATS Manager, Western Region
Pipeline & Hazardous Materials Safety Administration
Office: (720) 963-3175
Mobile: (303) 807-7200
thomas.finch@dot.gov

Weaver, Antoine (PHMSA)

From: Katchmar, Peter (PHMSA)
Sent: Wednesday, June 01, 2011 9:31 AM
To: PHMSA PHP80 Response; Hess, John (PHMSA)
Cc: PHMSA PHP500 WESTERN; PHP Accident/Incident Cadre <PHMSA>
Subject: Montana Flooding Update from the Western Region

Importance: High

The following is an e-mail string from the Western Region concerning recent and ongoing flooding in Montana. A summary report will be put together and submitted by COB tomorrow.

Bottom line is that the operators with lines in possible harm's way have either mitigated effects, shut in lines or are working toward mitigation. The Western Region engineers are monitoring the situation and remain in contact with operators in the region.

ConocoPhillips Pipeline (CPPL) is the only one with significant exposed pipe...they are planning secondary support as remediation.

Thank you,

Peter Katchmar

Western Region, PHMSA
Accident Coordinator
303/807-8458 (cell)
307/514-4456 (home office)

This message is intended only for the use of the individual or entity to which it is addressed and may contain information that is privileged, confidential, and exempt from disclosure under applicable law.

From: Hoidal, Chris (PHMSA)
Sent: Wednesday, June 01, 2011 6:15 AM
To: Katchmar, Peter (PHMSA)
Subject: FW: Montana flooding

Pete, here is a summary of all the major pipelines crossing the flooded areas in Montana. It may be useful in case we get a request, or you can forward the status up now. Bottom line is that CPPL is the only one with significant exposed pipe.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 2:48 PM
To: Hoidal, Chris (PHMSA); Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Just talked to CPPL. They have a pipeline with 54 feet exposed. They are talking about providing secondary support until flooding subsides. Discussions are focused around using a beam across the stream and then supporting the pipe with cables or such. They say the maximum unsupported span for this pipe is 60 feet and it sounds as if flow force is not an issue. After the water subsides they think they will bore this crossing. This creek drains into the Big Horn River. They are going to send me the exposed pipe report sometime soon which should provide more detail. Hope this helps.

Jerry Davis P.E.

USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Hoidal, Chris (PHMSA)
Sent: Tuesday, May 31, 2011 10:54 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Once I get the CPPL update from Davis, I plan on forwarding the final summary to HQ.

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 10:39 AM
To: Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Williston Basin reported that they elected to shut in their shallow pipeline crossing of the Yellowstone near Laurel due to the high river flows. They are able to run all capacity through the new Yellowstone River crossing that was bored under the river a couple of years ago. WBI district personnel are patrolling their lines as necessary but have not found any significant areas of concern. Except for the aforementioned Yellowstone crossing, Craig Wagner indicated that all of their river crossings are deeply bored or on the underside of bridges that are well above the river flows.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 9:45 AM
To: Petronis, Michael (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

I was just informed by CPPL that the washout on the Seminoe line is not on the Big Horn but on a drainage called Dauvis Creek, not sure what it drains to. They are meeting within the next hour to plan on what to do and probably to determine the degree of risk this posses.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 9:40 AM
To: Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

CHS – Billings Tank Farm and Billings Pump Station are experiencing some flooding but it has not significantly impacted operation. They have been conducting weekly aerial patrols lately – they have some areas underwater that they are monitoring more frequently and will continue to inspect as the water recedes. They do not have any washouts or mudslides but have some areas of erosion near the right of way that they are monitoring. The Missouri River crossing is a deep directional drill and should not be impacted

ExxonMobil – They are conducting patrols every other day recently and have not found any significant issues other than some erosion near/across the pipeline right of way. The Yellowstone River crossing depth was surveyed last fall and is

quite deep and should be adequate as long as the riverbank does not substantially erode and cause flooding in Riverside Park near Laurel.

Yellowstone River – the NWS reported that the Yellowstone at Billings crested at its 3rd highest level ever one day last week.

Weather forecast – sunny and dry finally for the next several days in the Billings area

I'll check the status of the riverbank at the pipeline crossings of the Yellowstone near Laurel and across Canyon Creek near Billings this afternoon.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 8:50 AM
To: Hoidal, Chris (PHMSA); Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA); Davis, Gerald (PHMSA)
Subject: RE: Montana flooding

CPPL: Exposed pipe on the Seminoe pipeline at approximately MP 32.8, on the Big Horn River a tributary to the Yellowstone and a world class trout fishery.

KMUSA: (Express pipeline) They have been checking and as of Friday there were no issues found, but they are closely watching. Their only issues have be gaining access to some crossing due to high water and closed roads.

Bridger (Poplar pipeline) They have not had any issues so far at Glendive where the pipeline crosses the Yellowstone but they are closely watching it. The pipeline is HDD under the Missouri and so far no problems their. They are having difficulties keeping water pumped out of their tank dikes. Both the Yellowstone at Glendive and the Missouri at Poplar are very high and fast.

I have a call into True to find out about the Butte pipeline where it crosses the Belle Fourche River but they have not gotten back to me yet. I will let you know when they call.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Hoidal, Chris (PHMSA)
Sent: Tuesday, May 31, 2011 8:06 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: Montana flooding

I know you guys continue to have flooding, particularly on the Missouri. Can you guys get together and get positive confirmation that the key crude and product lines are not having any problems.?

I guess my major concerns are Cenex, Yellowstone, and possibly some of the True systems. Just a quick consolidated email from both of you regarding which companies you have checked with, what they are doing in the way of patrolling, and the fact that there are not imminent (hopefully) hazards to the P/Ls.

I have a gut feeling that HQ may ask.

Weaver, Antoine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 10:12 AM
To: Hoidal, Chris (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

I went to check on the Yellowstone river crossing near Laurel a couple times last week. This is where ExxonMobil Silvertip and Williston Basin cross on there are some river bank erosion concerns - no imminent issues were observed. I'll check with CHS, CPPL and Williston Basin

---

From: Hoidal, Chris (PHMSA)
Sent: Tue 5/31/2011 8:05 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: Montana flooding

I know you guys continue to have flooding, particularly on the Missouri. Can you guys get together and get positive confirmation that the key crude and product lines are not having any problems.?

I guess my major concerns are Cenex, Yellowstone, and possibly some of the True systems. Just a quick consolidated email from both of you regarding which companies you have checked with, what they are doing in the way of patrolling, and the fact that there are not imminent (hopefully) hazards to the P/Ls.

I have a gut feeling that HQ may ask.

Weaver, Antoine (PHMSA)

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 12:00 PM
To: Petronis, Michael (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA); Davis, Gerald (PHMSA)
Subject: RE: Montana flooding

True Oil Butte and Poplar pipelines - Just received a call from True Oil HQ. They say that they are seeing an a higher than normal amount of exposed pipe along the Poplar, Butte, and Bicentennial ROWs during aerial patrols. They have been watching the Belle Fourche River crossing and so far nothing unusual. They reported that they have 4 valves on the Poplar pipeline that they have not been able to get to, because of flooding and wet conditions, to perform inspections and testing.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 9:40 AM
To: Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

CHS – Billings Tank Farm and Billings Pump Station are experiencing some flooding but it has not significantly impacted operation. They have been conducting weekly aerial patrols lately – they have some areas underwater that they are monitoring more frequently and will continue to inspect as the water recedes. They do not have any washouts or mudslides but have some areas of erosion near the right of way that they are monitoring. The Missouri River crossing is a deep directional drill and should not be impacted

ExxonMobil – They are conducting patrols every other day recently and have not found any significant issues other than some erosion near/across the pipeline right of way. The Yellowstone River crossing depth was surveyed last fall and is quite deep and should be adequate as long as the riverbank does not substantially erode and cause flooding in Riverside Park near Laurel.

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From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 8:50 AM
To: Hoidal, Chris (PHMSA); Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA); Davis, Gerald (PHMSA)
Subject: RE: Montana flooding

CPPL: Exposed pipe on the Seminoe pipeline at approximately MP 32.8, on the Big Horn River a tributary to the Yellowstone and a world class trout fishery.

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I have a call into True to find out about the Butte pipeline where it crosses the Belle Fourche River but they have not gotten back to me yet. I will let you know when they call.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Hoidal, Chris (PHMSA)
Sent: Tuesday, May 31, 2011 8:06 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: Montana flooding

I know you guys continue to have flooding, particularly on the Missouri. Can you guys get together and get positive confirmation that the key crude and product lines are not having any problems.?

I guess my major concerns are Cenex, Yellowstone, and possibly some of the True systems. Just a quick consolidated email from both of you regarding which companies you have checked with, what they are doing in the way of patrolling, and the fact that there are not imminent (hopefully) hazards to the P/Ls.

I have a gut feeling that HQ may ask.

Weaver, Antoine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Friday, October 22, 2010 1:07 PM
To: 'steven.v.everett@exxonmobil.com'
Cc: Finch, Thomas (PHMSA); Petronis, Michael (PHMSA)
Subject: Silvertip Pipeline - Yellowstone River

Steve – thanks for participating in the meeting with the City of Laurel on Wednesday at Riverside Park south of Laurel. As discussed during the meeting, by the end of next week please provide the estimated date by which ExxonMobil can provide accurate depth of cover information of the Silvertip Pipeline where it crosses the Yellowstone River and traverses through Riverside Park.

Thanks

Weaver, Antoine (PHMSA)

From: James Caniglia [jcaniglia@laurel.mt.gov]
Sent: Friday, October 15, 2010 5:55 PM
To: Finch, Thomas (PHMSA)
Cc: Petronis, Michael (PHMSA); Kurt Markegard
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Kurt,

Can you email the names and contact information of anyone you have talked to at the pipeline companies to Mike? He has talked with Exxon and they will be at Riverside Park on Wednesday.

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

http://www.laurel.mt.gov/

From: Thomas.Finch@dot.gov [mailto:Thomas.Finch@dot.gov]
Sent: Friday, October 15, 2010 9:50 AM
To: James Caniglia
Cc: michael.petronis@dot.gov; Kurt Markegard
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Welcome James. I appreciate Mike's help and assistance.

Tom Finch

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Friday, October 15, 2010 9:39 AM
To: Finch, Thomas (PHMSA)
Cc: Petronis, Michael (PHMSA); Kurt Markegard
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Thanks Tom, I appreciate your help.

Mike, if you have any questions feel free to give me call.

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

http://www.laurel.mt.gov/

From: Thomas.Finch@dot.gov [mailto:Thomas.Finch@dot.gov]
Sent: Friday, October 15, 2010 9:03 AM

To: James Caniglia
Cc: michael.petronis@dot.gov
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

James,

Our Mike Petronis and the operator are planning to meet at the park/dyke at 1:30 pm next Wednesday October 20th. Mike wanted me to let you know so that you could meet them there. Mike Petronis's phone number is; 720-884-6538.

I will be traveling all of next week so please feel free to contact Mike directly concerning any other arrangements for next week's meeting at the park/dyke.

Thank you,

Tom Finch

From: Finch, Thomas (PHMSA)
Sent: Wednesday, October 06, 2010 8:49 AM
To: 'James Caniglia'
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Welcome James!

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Wednesday, October 06, 2010 8:45 AM
To: Finch, Thomas (PHMSA)
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Thanks Tom, I appreciate your help!

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

http://www.laurel.mt.gov/

From: Thomas.Finch@dot.gov [mailto:Thomas.Finch@dot.gov]
Sent: Wednesday, October 06, 2010 8:24 AM
To: James Caniglia
Cc: Kurt Markegard
Subject: FW: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

James,

I just got an e-mail from our inspector in Billings. He is out on an II Inspection this week. He is going to try to set something up to go out to the site during the week of October 18th. We will keep you posted.

Tom Finch
Western Region CATS Manager
U.S. DOT/PHMSA
(720) 963-3175 (office)

From: Finch, Thomas (PHMSA)
Sent: Tuesday, October 05, 2010 3:57 PM
To: 'James Caniglia'
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Welcome James. I think you sent some good information. I will let you know when they can make it. Have a good evening.

Thanks.

Tom Finch

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Tuesday, October 05, 2010 3:54 PM
To: Finch, Thomas (PHMSA)
Cc: Kurt Markegard
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Thanks Tom,

Let me know if you would like any other information and when they can make it.

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

http://www.laurel.mt.gov/

From: Thomas.Finch@dot.gov [mailto:Thomas.Finch@dot.gov]
Sent: Tuesday, October 05, 2010 3:12 PM
To: James Caniglia
Cc: Kurt Markegard
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

James,

Thanks for this information. I have e-mailed our Montana Engineers concerning a visit and I am awaiting their reply. They are both traveling this week. However, I will get back to you as soon as they get back to me.

Thanks again,

Tom Finch
Western Region CATS Manager
U.S. DOT/PHMSA
(720) 963-3175 (office)

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Tuesday, October 05, 2010 2:35 PM
To: Finch, Thomas (PHMSA); Kurt Markegard
Subject:

Tom,

I attached a PDF plat map of Riverside Park. The plat does not show easements for the pipelines and I am not sure if that is an oversight or if there are no easements. Obviously you can tell the pipelines are present from pipeline maps. The links below discuss some of the issues we are dealing with. Please let me know when someone will be able to visit the park and assess the safety issue as it might be helpful for us to be there.

Thanks,

http://billingsgazette.com/news/local/article_23dd4596-c9eb-11df-87ed-001cc4c002e0.html

http://www.laureloutlook.com/articles/2010/06/09/news/big_story/01big.txt

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

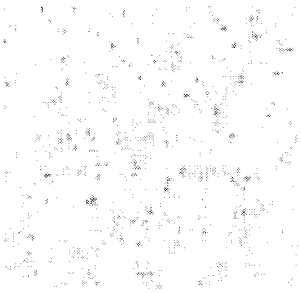
http://www.laurel.mt.gov/

Weaver, Antoine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Wednesday, October 06, 2010 1:35 AM
To: Finch, Thomas (PHMSA); Davis, Gerald (PHMSA)
Cc: Reineke, Ross (PHMSA); Flanders, Bill (PHMSA)
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

I can look at it sometime. I'm on an II audit right near there next week but may need to travel to Bison to observe a hydrotest. I could check it out sometime during the week of October 18th. We might want to contact ExxonMobil Pipeline in Billings to participate as well.

From: Finch, Thomas (PHMSA)
Sent: Tue 10/5/2010 5:08 PM
To: Davis, Gerald (PHMSA); Petronis, Michael (PHMSA)
Cc: Reineke, Ross (PHMSA); Flanders, Bill (PHMSA)
Subject: FW: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture



FYI. I believe the only pipeline we have left at issue here is ExxonMobil's. I think for the interest of safety's sake, one of us ought to visit the park and asses this for any pipeline safety issues.

Mike since you are closest to this location would you mind looking at it? Or Jerry, considering your line of expertise would you like to look at it?

Also, if one or both of you go, do you want James C. or Kurt M. of the City of Laurel to be there when you go? It is their park (and levy?).

Thanks,

Tom

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Tuesday, October 05, 2010 2:35 PM
To: Finch, Thomas (PHMSA); Kurt Markegard
Subject:

Tom,

I attached a PDF plat map of Riverside Park. The plat does not show easements for the pipelines and I am not sure if that is an oversight or if there are no easements. Obviously you can tell the pipelines are present from pipeline maps. The links below discuss some of the issues we are dealing with. Please let me know when someone will be able to visit the park and assess the safety issue as it might be helpful for us to be there.

Thanks,

http://billingsgazette.com/news/local/article_23dd4596-c9eb-11df-87ed-001cc4c002e0.html

http://www.laureloutlook.com/articles/2010/06/09/news/big_story/01big.txt

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044

http://www.laurel.mt.gov/

Weaver, Antoine (PHMSA)

From: Davis, Gerald (PHMSA)
Sent: Tuesday, October 05, 2010 4:01 PM
To: Finch, Thomas (PHMSA); Petronis, Michael (PHMSA)
Cc: Flanders, Bill (PHMSA); Reineke, Ross (PHMSA)
Subject: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

The guys I am working with right now think that it was a Williston Basin pipeline 6 or 8 inch that washed out this year at or shortly after high water. They replaced the line by boring under the Yellowstone. CPPL has a 8 inch crude line that is idled and ExxonMobil also has an active line in the vicinity of the WBI line.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Finch, Thomas (PHMSA)
Sent: Tuesday, October 05, 2010 1:49 PM
To: Davis, Gerald (PHMSA); Petronis, Michael (PHMSA)
Cc: Flanders, Bill (PHMSA); Reineke, Ross (PHMSA)
Subject: FW: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Good afternoon Jerry and Mike.

I talked to James Canaglia when he called me back late yesterday concerning his "We (City of Laurel) are concerned about a group of pipelines (Natural Gas and Oil) that run under the Yellowstone River. These pipelines are protected by a levee that was initially built by the Railroad in the late 1800s. The levee is now suffering severe degradation that has already caused a rupture in one of the pipelines (Natural gas) a couple of months ago. We would like to know what responsibilities does the operator have in regard to the maintenance of the levee. We are concerned that the levee will totally deteriorate and subsequently cause ruptures to the rest of the pipelines that run under the river."

Are either of you aware which gas line was ruptured a couple of months ago? He seemed to indicate that it was Williston Basin's. I told him our responsibility was pipeline safety and that the operator(s) need to assure us that these pipelines are safe anywhere, including from damage if the levee breaks.

Bottom line is that James is going to scan and e-mail or mail me a plat and/or newspaper articles concerning these pipelines and the levee, which was built by the Corps of Engineers in the late 19th Century.

I will keep in touch with you both when I receive further information. Jerry you are our Civil (Dam) Engineering guru and Michael you live closer to Laurel so I will probably be consulting with both of you on this.

Thanks.

Tom

Thomas Finch
U.S. Department of Transportation (USDOT)
Pipeline & Hazardous Materials Safety Administration (PHMSA)
Western Region CATS Manager
e-mail: thomas.finch@dot.gov
Tel: 720-963-3175
Cell: 303-807-7200
Fax: 720-963-3161

From: Reineke, Ross (PHMSA)
Sent: Friday, October 01, 2010 1:18 PM
To: Finch, Thomas (PHMSA)
Cc: Reineke, Ross (PHMSA)
Subject: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Thanks Tom.

From: Finch, Thomas (PHMSA)
Sent: Friday, October 01, 2010 12:04 PM
To: Satterthwaite, Cameron (PHMSA); Reineke, Ross (PHMSA)
Cc: Flanders, Bill (PHMSA)
Subject: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Cameron,

I will contact Mr. Canaglia this Monday in between my two mandatory meetings. Today I need to finish getting all the correspondence entered for Marilyn Burke concerning an AP Press FOIA requesting all correspondence between us/PHMSA and the CA PUC since 2007. Since I was the State Liaison up until a year ago, that is a lot of e-mails, etc.

Thanks.

Tom Finch
Western Region CATS Manager
U.S. DOT/PHMSA
(720) 963-3175 (office)

From: Satterthwaite, Cameron (PHMSA)
Sent: Friday, October 01, 2010 11:40 AM
To: Reineke, Ross (PHMSA); Finch, Thomas (PHMSA)
Cc: Flanders, Bill (PHMSA)
Subject: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Ross or Tom,

Can one of you contact Mr. Canaglia regarding his question below?

Caller: John Canaglia
Affiliation: City of Laurel , Office of Planning
Phone No: 406-628-4796
Location: Montana
Question: We (City of Laurel) are concerned about a group of pipelines (Natural Gas and Oil) that run under the Yellowstone River. These pipelines are protected by a levee that was initially built by the Railroad in the late 1800s. The levee is now suffering severe degradation that has already caused a rupture in one of the pipelines (Natural gas) a couple of months ago. We would like to know what responsibilities does the operator have in regard to the maintenance of the levee. We are concerned that the levee will totally deteriorate and subsequently cause ruptures to the rest of the pipelines that run under the river.

Cameron H. Satterthwaite
Pipeline and Hazardous Material Safety Administration
Transportation Regulations Spec.

East Bldg PHP-30
1200 New Jersey Ave, SE
Washington, DC 20590
Tel: 202-366-1319

Weaver, Antoine (PHMSA)

From: Finch, Thomas (PHMSA)
Sent: Wednesday, June 01, 2011 4:42 PM
To: Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Subject: RE: Yellowstone river at laurel

Mike – thanks Chris is on annual leave. Terry is acting in Chris's stead so I am copying Terry concerning ExxonMobil providing specific criteria for when they would shut the line down and block it in.

From: Petronis, Michael (PHMSA)
Sent: Wednesday, June 01, 2011 2:36 PM
To: Finch, Thomas (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Yellowstone river at laurel

Tom – from what I remember from the survey the line is not that deep under the park – maybe more like 4 or 5 feet from what I remember. It is 11 -13 feet under the river and at the current location of the banks. I'm not sure if we should have ExxonMobil provide specific criteria for when they would shut the line down and block it in – ie. If the river bank completely eroded and the path of the river was diverted through the park. I suggested they develop this a while back but they seemed reluctant to provide anything specific.

From: Finch, Thomas (PHMSA)
Sent: Wednesday, June 01, 2011 2:01 PM
To: Petronis, Michael (PHMSA); 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: RE: Yellowstone river at laurel

Laura just called me and she indicated that the depth of cover was from 11 feet to 13 feet averaging 12' deep. Thanks for the call Laura and please correct me if I misheard you.

Tom Finch

From: Petronis, Michael (PHMSA)
Sent: Wednesday, June 01, 2011 1:57 PM
To: Finch, Thomas (PHMSA); 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: RE: Yellowstone river at laurel

I have been in contact with Larry the last few days and he has indicated that ExxonMobil staff are conducting frequent inspections of the river crossing. I visited the site a couple of days last week myself.

Larry – could you send everyone a copy of the recent depth of cover survey across the river or at least provide an estimated depth of the line beneath the river and on each of the banks?

From what I recall, the pipeline should be fine unless the south riverbank completely erodes and the river starts to flow through the park.

Thanks

From: Finch, Thomas (PHMSA)
Sent: Wednesday, June 01, 2011 1:25 PM
To: 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); Petronis, Michael (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: FW: Yellowstone river at laurel

Good afternoon Laura and Larry.

As Kurt stated, The little white sign on the far side is where your Exxon line is located. The City of Laurel is not trying to protect that bank. Erosion is occurring. Please, have someone check on this and give us an update of the status of your pipeline at this location.

Thanks.

Tom

Thomas Finch
CATS Manager, Western Region
Pipeline & Hazardous Materials Safety Administration
Office: (720) 963-3175
Mobile: (303) 807-7200
thomas.finch@dot.gov

From: Kurt Markegard [mailto:kmarkegard@laurel.mt.gov]
Sent: Wednesday, June 01, 2011 12:46 PM
To: Finch, Thomas (PHMSA)
Cc: dhabermann@mt.gov; City Mayor; hjensen@laurel.mt.gov
Subject: FW: Yellowstone river at laurel

Tom,

This is what I sent and to whom.

Thanks,

Kurt

From: Kurt Markegard
Sent: Wednesday, May 25, 2011 1:15 PM
To: laura.k.sleevi@exxonmobil.com
Subject: Yellowstone river at laurel

The little white sign on the far side is where exxon line is located. We are not trying to protect that bank. Eroision is happening to what extent I do not know. Bank may not hold the night

Sent from my Android phone using TouchDown (www.nitrodesk.com)

Keener, Blaine (PHMSA)

From: Finch, Thomas (PHMSA)
Sent: Thursday, July 07, 2011 1:02 PM
To: Keener, Blaine (PHMSA)
Cc: Hoidal, Chris (PHMSA); Nguyen, Huy (PHMSA)
Subject: FW: Yellowstone river at laurel- Sensitive Material
Attachments: YELLOWSTONE12-Model.pdf

Importance: High

Blaine -

Note from email below - "Larry, Thank you in advance for having the profile sent to me.

I realize your drawings are security sensitive. This drawing will be for PHMSA personnel only. We would not distribute it without your permission to distribute it."

Thanks.

Tom

-----Original Message-----
From: larry.e.hawthorne@exxonmobil.com [mailto:larry.e.hawthorne@exxonmobil.com]
Sent: Thursday, June 02, 2011 11:54 AM
To: Finch, Thomas (PHMSA)
Cc: laura.k.sleevi@exxonmobil.com; jason.j.montgomery@exxonmobil.com; gary.w.hartmann@exxonmobil.com
Subject: Yellowstone river at laurel- Sensitive Material

Tom, attached is the profile for the 12" Pipeline at Yellowstone River near Laurel,

(See attached file: YELLOWSTONE12-Model.pdf) I will be out in the field this afternoon away from my computer for the next 3-4 hrs, and please advise if you need anything else.

regards-
Larry "Doc" Hawthorne-
Pipeline Safety Compliance Advisor
(SHE)-Safety,Health,&Environmental Department Office 903-654-5345-(CELL)903-879-0313- FAX 903-654-5302
email: larry.e.hawthorne@exxonmobil.com
1604 South 15th St.. Corsicana, Texas 75110

<Thomas.Finch@dot.gov>

06/02/2011 08:28 AM

To <larry.e.hawthorne@exxonmobil.com>
cc
Subject RE: Yellowstone river at laurel- Sensitive Material

Larry, Thank you in advance for having the profile sent to me.

I realize your drawings are security sensitive. This drawing will be for PHMSA personnel only. We would not distribute it without your permission to distribute it.

Have a good meeting. I will look for the drawing sometime after 12:00 your time.

Thanks again.

Tom Finch
USDOT / PHMSA / OPS
Western Region
Office: 720-963-3175
Cell: 303-807-7200
Fax: 720-963-3161
thomas.finch@dot.gov

-----Original Message-----
From: larry.e.hawthorne@exxonmobil.com
[mailto:larry.e.hawthorne@exxonmobil.com]
Sent: Thursday, June 02, 2011 7:22 AM
To: Finch, Thomas (PHMSA)
Subject: Yellowstone river at laurel- Sensitive Material

Tom, I am having the electronic copy of the profile sent to me where I can forward you a copy.

EMPCo treat these drawing are sensitive and security materials.

Will this drawing be for PHMSA personnel only and not for distribution ?

I have a 8:30 - 12:00 meeting this morning and will sent the drawing after the meeting.

regards-
Larry "Doc" Hawthorne-
Pipeline Safety Compliance Advisor
(SHE)-Safety,Health,&Environmental Department Office 903-654-5345-(CELL)903-879-0313- FAX 903-654-5302
email: larry.e.hawthorne@exxonmobil.com
1604 South 15th St.. Corsicana, Texas 75110

<Thomas.Finch@
dot.gov>

To
<larry.e.hawthorne@exxonmobil.com>
06/01/2011 cc
05:37 PM
Subject
RE: Yellowstone river at laurel

Thanks "Doc". Have a safe drive.
Tom

From: larry.e.hawthorne@exxonmobil.com
[mailto:larry.e.hawthorne@exxonmobil.com]
Sent: Wednesday, June 01, 2011 4:27 PM
To: Finch, Thomas (PHMSA); Petronis, Michael (PHMSA); laura.k.sleevi@exxonmobil.com
Cc: Larson, Terrence (PHMSA); kmarkegard; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA); gary.w.hartmann@exxonmobil.com
Subject: Re: Yellowstone river at laurel

Yes I am. Driving to Little Rock Ark and will forward the imformation tomorrow.
Regards
Doc

From: [Thomas.Finch@dot.gov]
Sent: 06/01/2011 04:00 PM AST
To: <michael.petronis@dot.gov>; Laura Sleevi; Larry Hawthorne
Cc: <terrence.larson@dot.gov>; <kmarkegard@laurel.mt.gov>; <huy.v.nguyen@dot.gov>; <Peter.Katchmar@dot.gov>; <chris.hoidal@dot.gov>
Subject: RE: Yellowstone river at laurel

Laura just called me and she indicated that the depth of cover was from 11 feet to 13 feet averaging 12' deep. Thanks for the call Laura and please correct me if I misheard you.

Tom Finch

From: Petronis, Michael (PHMSA)
Sent: Wednesday, June 01, 2011 1:57 PM
To: Finch, Thomas (PHMSA); 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: RE: Yellowstone river at laurel

I have been in contact with Larry the last few days and he has indicated that ExxonMobil staff are conducting frequent inspections of the river crossing. I visited the site a couple of days last week myself.

Larry - could you send everyone a copy of the recent depth of cover survey across the river or at least provide an estimated depth of the line beneath the river and on each of the banks?

From what I recall, the pipeline should be fine unless the south riverbank completely erodes and the river starts to flow through the park.

Thanks

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Sent: Wednesday, June 01, 2011 1:25 PM
To: 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); Petronis, Michael (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: FW: Yellowstone river at laurel

Good afternoon Laura and Larry.

As Kurt stated, The little white sign on the far side is where your Exxon line is located.
The City of Laurel is not trying to protect that bank.
Erosion is occurring. Please, have someone check on this and give us an update of the status of your pipeline at this location.

Thanks.

Tom

Thomas Finch
CATS Manager, Western Region
Pipeline & Hazardous Materials Safety Administration
Office: (720) 963-3175
Mobile: (303) 807-7200
thomas.finch@dot.gov

From: Kurt Markegard [mailto:kmarkegard@laurel.mt.gov]
Sent: Wednesday, June 01, 2011 12:46 PM
To: Finch, Thomas (PHMSA)
Cc: dhabermann@mt.gov; City Mayor; hjensen@laurel.mt.gov
Subject: FW: Yellowstone river at laurel

Tom,

This is what I sent and to whom.

Thanks,

Kurt

From: Kurt Markegard
Sent: Wednesday, May 25, 2011 1:15 PM
To: laura.k.sleevi@exxonmobil.com

Subject: Yellowstone river at laurel

The little white sign on the far side is where exxon line is located. We are not trying to protect that bank. Eroision is happening to what extent I do not know. Bank may not hold the night

Sent from my Android phone using TouchDown (www.nitrodesk.com)

Weaver, Antoine (PHMSA)

From: Larson, Terrence (PHMSA)
Sent: Thursday, June 02, 2011 12:48 PM
To: Petronis, Michael (PHMSA); Finch, Thomas (PHMSA); Nguyen, Huy (PHMSA)
Subject: RE: IMG00343-20110601-1608.jpg

Pretty amazing high flow conditions. Express crosses at this location as well. It was directionally drilled and well below the river.

From: Petronis, Michael (PHMSA)
Sent: Thursday, June 02, 2011 10:17 AM
To: Finch, Thomas (PHMSA); Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Subject: FW: IMG00343-20110601-1608.jpg

Boat ramp damage and riverbank erosion at Riverside Park near Laurel (June1). ExxonMobil's Silvertip Pipeline crosses the river about 100 ft downstream of the boatramp. (Photo is looking downstream)

From: Petronis, Michael (PHMSA)
Sent: Thu 6/2/2011 9:01 AM
To: Petronis, Michael (PHMSA)
Subject: IMG00343-20110601-1608.jpg

Keener, Blaine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Thursday, June 02, 2011 12:17 PM
To: Finch, Thomas (PHMSA); Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Subject: FW: IMG00343-20110601-1608.jpg
Attachments: IMG00343-20110601-1608.jpg

Boat ramp damage and riverbank erosion at Riverside Park near Laurel (June1). ExxonMobil's Silvertip Pipeline crosses the river about 100 ft downstream of the boatramp. (Photo is looking downstream)

From: Petronis, Michael (PHMSA)
Sent: Thu 6/2/2011 9:01 AM
To: Petronis, Michael (PHMSA)
Subject: IMG00343-20110601-1608.jpg



Kurdock, Brianne (PHMSA)

From: Hoidal, Chris (PHMSA)
Sent: Wednesday, July 13, 2011 6:10 PM
To: Kurdock, Brianne (PHMSA)
Subject: FW: Montana Flooding Update from the Western Region

Importance: High

From: Katchmar, Peter (PHMSA)
Sent: Wednesday, June 01, 2011 7:31 AM
To: PHMSA PHP80 Response; Hess, John (PHMSA)
Cc: PHMSA PHP500 WESTERN; PHP Accident/Incident Cadre <PHMSA>
Subject: Montana Flooding Update from the Western Region
Importance: High

The following is an e-mail string from the Western Region concerning recent and ongoing flooding in Montana. A summary report will be put together and submitted by COB tomorrow.

Bottom line is that the operators with lines in possible harm's way have either mitigated effects, shut in lines or are working toward mitigation. The Western Region engineers are monitoring the situation and remain in contact with operators in the region.

ConocoPhillips Pipeline (CPPL) is the only one with significant exposed pipe...they are planning secondary support as remediation.

Thank you,

Peter Katchmar

Western Region, PHMSA
Accident Coordinator
303/807-8458 (cell)
307/514-4456 (home office)

This message is intended only for the use of the individual or entity to which it is addressed and may contain information that is privileged, confidential, and exempt from disclosure under applicable law.

From: Hoidal, Chris (PHMSA)
Sent: Wednesday, June 01, 2011 6:15 AM
To: Katchmar, Peter (PHMSA)
Subject: FW: Montana flooding

Pete, here is a summary of all the major pipelines crossing the flooded areas in Montana. It may be useful in case we get a request, or you can forward the status up now. Bottom line is that CPPL is the only one with significant exposed pipe.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 2:48 PM
To: Hoidal, Chris (PHMSA); Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Just talked to CPPL. They have a pipeline with 54 feet exposed. They are talking about providing secondary support until flooding subsides. Discussions are focused around using a beam across the stream and then supporting the pipe with cables or such. They say the maximum unsupported span for this pipe is 60 feet and it sounds as if flow force is not an issue. After the water subsides they think they will bore this crossing. This creek drains into the Big Horn River. They are going to send me the exposed pipe report sometime soon which should provide more detail. Hope this helps.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Hoidal, Chris (PHMSA)
Sent: Tuesday, May 31, 2011 10:54 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Once I get the CPPL update from Davis, I plan on forwarding the final summary to HQ.

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 10:39 AM
To: Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

Williston Basin reported that they elected to shut in their shallow pipeline crossing of the Yellowstone near Laurel due to the high river flows. They are able to run all capacity through the new Yellowstone River crossing that was bored under the river a couple of years ago. WBI district personnel are patrolling their lines as necessary but have not found any significant areas of concern. Except for the aforementioned Yellowstone crossing, Craig Wagner indicated that all of their river crossings are deeply bored or on the underside of bridges that are well above the river flows.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 9:45 AM
To: Petronis, Michael (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

I was just informed by CPPL that the washout on the Seminoe line is not on the Big Horn but on a drainage called Dauvis Creek, not sure what it drains to. They are meeting within the next hour to plan on what to do and probably to determine the degree of risk this posses.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Petronis, Michael (PHMSA)
Sent: Tuesday, May 31, 2011 9:40 AM
To: Davis, Gerald (PHMSA); Hoidal, Chris (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: RE: Montana flooding

CHS – Billings Tank Farm and Billings Pump Station are experiencing some flooding but it has not significantly impacted operation. They have been conducting weekly aerial patrols lately – they have some areas underwater that they are monitoring more frequently and will continue to inspect as the water recedes. They do not have any washouts or mudslides but have some areas of erosion near the right of way that they are monitoring. The Missouri River crossing is a deep directional drill and should not be impacted

ExxonMobil – They are conducting patrols every other day recently and have not found any significant issues other than some erosion near/across the pipeline right of way. The Yellowstone River crossing depth was surveyed last fall and is quite deep and should be adequate as long as the riverbank does not substantially erode and cause flooding in Riverside Park near Laurel.

Yellowstone River – the NWS reported that the Yellowstone at Billings crested at its 3rd highest level ever one day last week.

Weather forecast – sunny and dry finally for the next several days in the Billings area

I'll check the status of the riverbank at the pipeline crossings of the Yellowstone near Laurel and across Canyon Creek near Billings this afternoon.

From: Davis, Gerald (PHMSA)
Sent: Tuesday, May 31, 2011 8:50 AM
To: Hoidal, Chris (PHMSA); Petronis, Michael (PHMSA)
Cc: Nguyen, Huy (PHMSA); Davis, Gerald (PHMSA)
Subject: RE: Montana flooding

CPPL: Exposed pipe on the Seminoe pipeline at approximately MP 32.8, on the Big Horn River a tributary to the Yellowstone and a world class trout fishery.

KMUSA: (Express pipeline) They have been checking and as of Friday there were no issues found, but they are closely watching. Their only issues have be gaining access to some crossing due to high water and closed roads.

Bridger (Poplar pipeline) They have not had any issues so far at Glendive where the pipeline crosses the Yellowstone but they are closely watching it. The pipeline is HDD under the Missouri and so far no problems their. They are having difficulties keeping water pumped out of their tank dikes. Both the Yellowstone at Glendive and the Missouri at Poplar are very high and fast.

I have a call into True to find out about the Butte pipeline where it crosses the Belle Fourche River but they have not gotten back to me yet. I will let you know when they call.

Jerry Davis P.E.
USDOT/PHMSA
725 Middlemas Rd.
Helena, MT 59602
Work/Cell (202) 510-6147

From: Hoidal, Chris (PHMSA)
Sent: Tuesday, May 31, 2011 8:06 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Nguyen, Huy (PHMSA)
Subject: Montana flooding

I know you guys continue to have flooding, particularly on the Missouri. Can you guys get together and get positive confirmation that the key crude and product lines are not having any problems.?

I guess my major concerns are Cenex, Yellowstone, and possibly some of the True systems. Just a quick consolidated email from both of you regarding which companies you have checked with, what they are doing in the way of patrolling, and the fact that there are not imminent (hopefully) hazards to the P/Ls.

I have a gut feeling that HQ may ask.

Weaver, Antoine (PHMSA)

From: Finch, Thomas (PHMSA)
Sent: Wednesday, June 01, 2011 3:25 PM
To: 'laura.k.sleevi@exxonmobil.com'; 'larry.e.hawthorne@exxonmobil.com'
Cc: Larson, Terrence (PHMSA); Petronis, Michael (PHMSA); 'Kurt Markegard'; Nguyen, Huy (PHMSA); Katchmar, Peter (PHMSA); Hoidal, Chris (PHMSA)
Subject: FW: Yellowstone river at laurel
Attachments: IMG_20110525_130808.jpg; IMG_20110525_130748.JPG; IMG_20110531_145428.JPG

Good afternoon Laura and Larry.

As Kurt stated, The little white sign on the far side is where your Exxon line is located. The City of Laurel is not trying to protect that bank. Erosion is occurring. Please, have someone check on this and give us an update of the status of your pipeline at this location.

Thanks.

Tom

Thomas Finch
CATS Manager, Western Region
Pipeline & Hazardous Materials Safety Administration
Office: (720) 963-3175
Mobile: (303) 807-7200
thomas.finch@dot.gov

From: Kurt Markegard [mailto:kmarkegard@laurel.mt.gov]
Sent: Wednesday, June 01, 2011 12:46 PM
To: Finch, Thomas (PHMSA)
Cc: dhabermann@mt.gov; City Mayor; hjensen@laurel.mt.gov
Subject: FW: Yellowstone river at laurel

Tom,

This is what I sent and to whom.

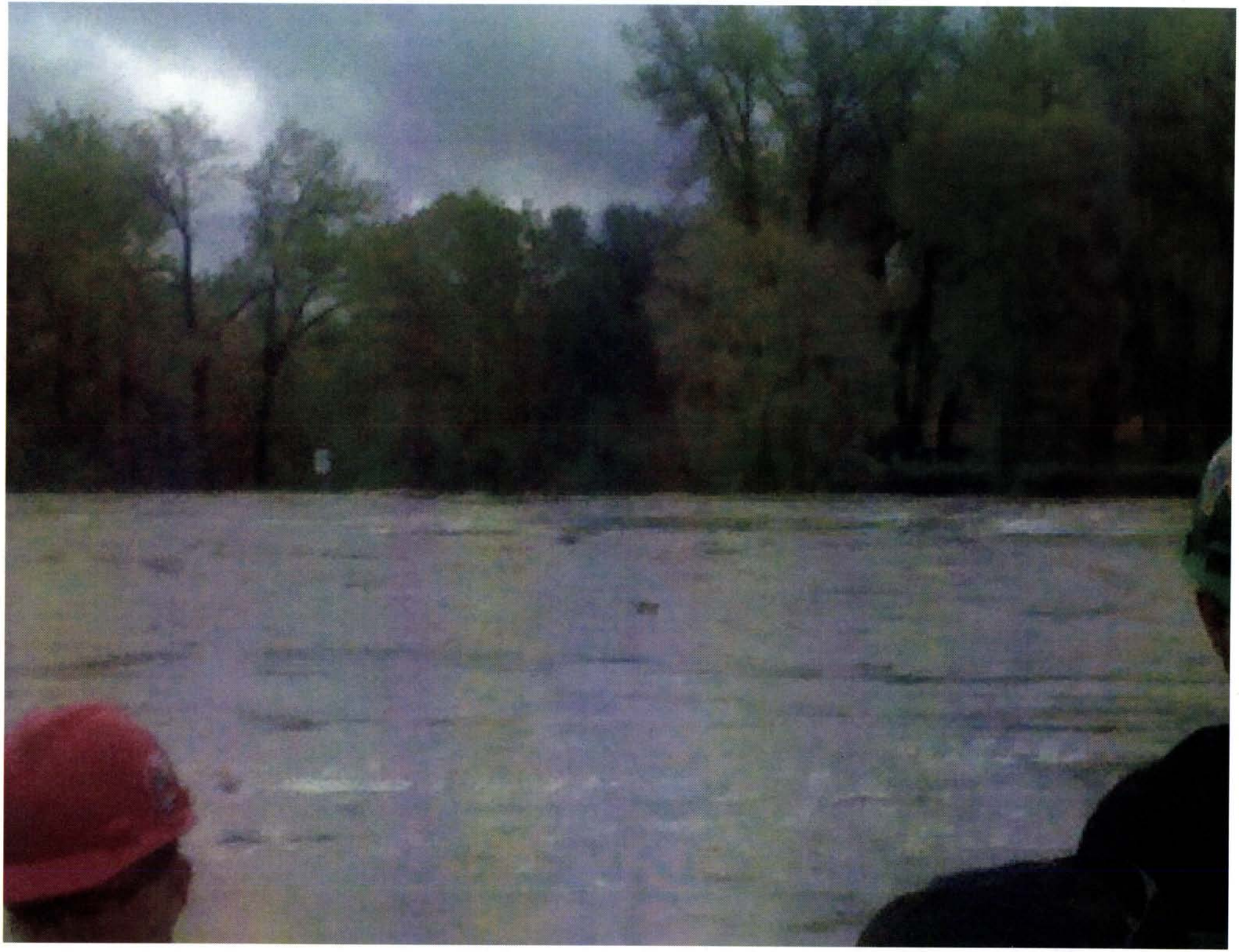
Thanks,

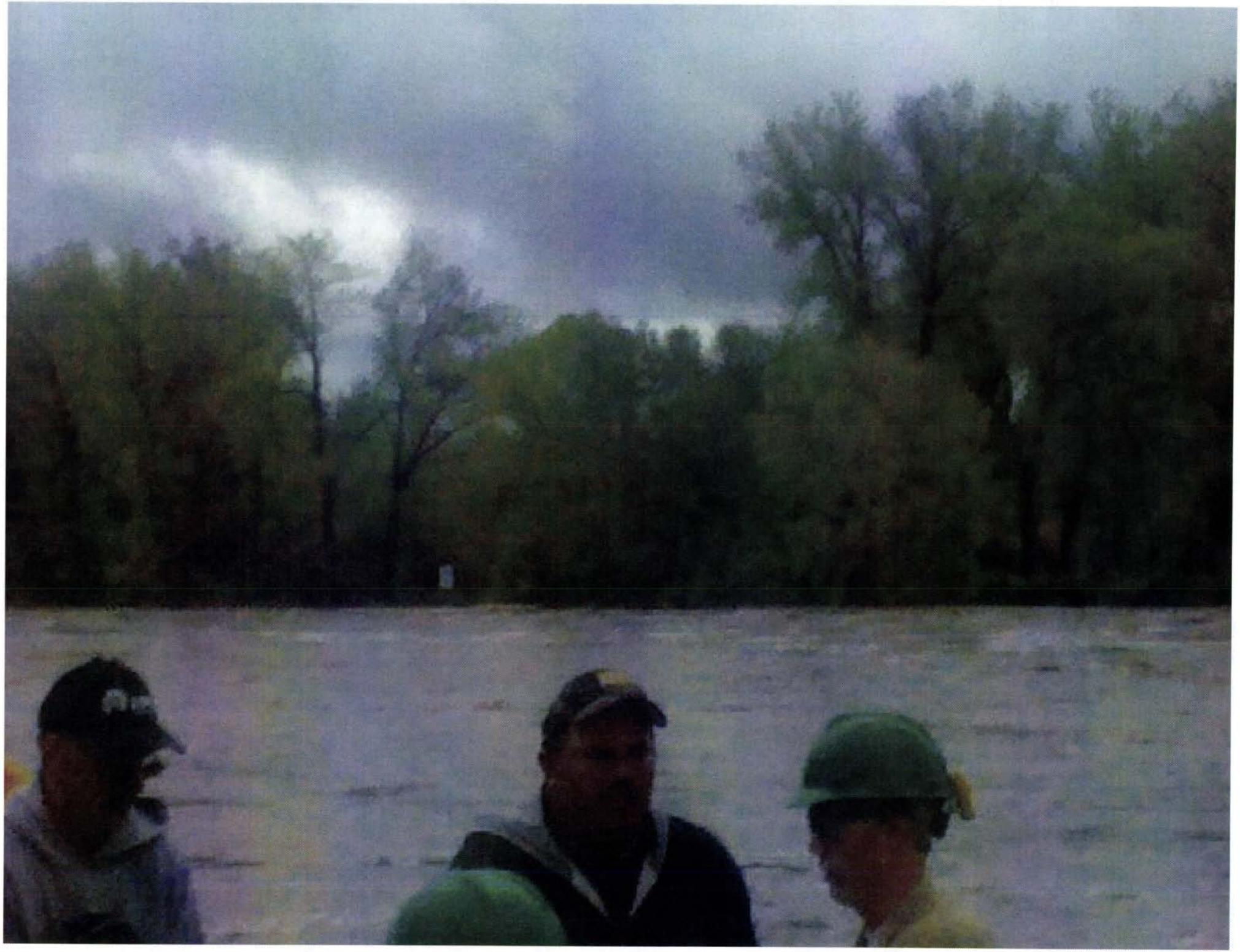
Kurt

From: Kurt Markegard
Sent: Wednesday, May 25, 2011 1:15 PM
To: laura.k.sleevi@exxonmobil.com
Subject: Yellowstone river at laurel

The little white sign on the far side is where exxon line is located. We are not trying to protect that bank. Eroision is happening to what extent I do not know. Bank may not hold the night

Sent from my Android phone using TouchDown (www.nitrodesk.com)







Keener, Blaine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Friday, October 29, 2010 10:32 AM
To: Bonnett, Kristi (PHMSA)
Cc: Finch, Thomas (PHMSA); Nguyen, Huy (PHMSA)
Subject: FW: 6-10 week estimate for Depth of Cover@ Yellowstone River

Kristi - please enter this email correspondence in the Tracker. Thanks.

From: larry.e.hawthorne@exxonmobil.com [mailto:larry.e.hawthorne@exxonmobil.com]
Sent: Thu 10/28/2010 6:57 PM
To: Petronis, Michael (PHMSA)
Cc: steven.v.everett@exxonmobil.com
Subject: 6-10 week estimate for Depth of Cover@ Yellowstone River

Mr. Michael Petronis,

This is a response to the request made to ExxonMobil Pipeline on Oct 22, 2010 to Steve Everett requesting an update on when ExxonMobil Pipeline can provide an accurate depth of cover along our pipeline that crosses the Yellowstone River.

ExxonMobil Pipeline's estimated date to provide an accurate depth of cover information of the Silvertip pipeline where it crossed the Yellowstone River and traverses through Riverside Park is 6-10 weeks. Our Right of Way personnel are working with the Montana Dept. Natural Resources & Conservation (MDNRC) to see if a 310 permit is required.

If no permit is required, this work can be accomplished in approximately 6 weeks.

Should you need further questions, please feel free to contact me at 903-654-5345 or email larry.e.hawthorne@exxonmobil.com.

Sincerely,

Larry "Doc" Hawthorne-
Pipeline Safety Compliance Advisor
(SHE)-Safety,Health,&Environmental Department
Office 903-654-5345-(CELL)903-879-0313-
FAX 903-654-5302
email: larry.e.hawthorne@exxonmobil.com
1604 South 15th St.. Corsicana, Texas 75110

Keener, Blaine (PHMSA)

From: Petronis, Michael (PHMSA)
Sent: Thursday, October 07, 2010 12:48 AM
To: Finch, Thomas (PHMSA)
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

I'm on Bison this week - I'll try to give ExxonMobil and Mr. Caniglia a call on Friday to set up a meeting.

From: Finch, Thomas (PHMSA)
Sent: Wed 10/6/2010 9:56 AM
To: Petronis, Michael (PHMSA); Davis, Gerald (PHMSA)
Cc: Reineke, Ross (PHMSA); Flanders, Bill (PHMSA); Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

Thanks Mike. Sometime during the week of October 18th would be good. I agree that we should contact ExxonMobil Pipeline in Billings to participate as well. Since you are checking this out, please contact ExxonMobil Pipeline in Billings and set up a day and time that is best for you. Let me know your plans and I will let the City of Laurel know unless you just want to contact them directly.

I noticed you sent this at 11:35 PM so thanks for taking the time to respond late last night.

Thanks again..

Tom

Thomas Finch
U.S. Department of Transportation (USDOT)
Pipeline & Hazardous Materials Safety Administration (PHMSA)
Western Region CATS Manager
e-mail: thomas.finch@dot.gov
Tel: 720-963-3175
Cell: 303-807-7200
Fax: 720-963-3161

From: Petronis, Michael (PHMSA)
Sent: Tuesday, October 05, 2010 11:35 PM
To: Finch, Thomas (PHMSA); Davis, Gerald (PHMSA)
Cc: Reineke, Ross (PHMSA); Flanders, Bill (PHMSA)
Subject: RE: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

I can look at it sometime. I'm on an II audit right near there next week but may need to travel to Bison to observe a hydrotest. I could check it out sometime during the week of October 18th. We might want to contact ExxonMobil Pipeline in Billings to participate as well.

From: Finch, Thomas (PHMSA)
Sent: Tue 10/5/2010 5:08 PM
To: Davis, Gerald (PHMSA); Petronis, Michael (PHMSA)
Cc: Reineke, Ross (PHMSA); Flanders, Bill (PHMSA)
Subject: FW: RE: CATs Questions: Pipelines under Yellowstone River In danger of rupture

FYI. I believe the only pipeline we have left at issue here is ExxonMobil's. I think for the interest of safety's sake, one of us ought to visit the park and asses this for any pipeline safety issues.

Mike since you are closest to this location would you mind looking at it? Or Jerry, considering your line of expertise would you like to look at it?

Also, if one or both of you go, do you want James C. or Kurt M. of the City of Laurel to be there when you go? It is their park (and levy?).

Thanks,

Tom

From: James Caniglia [mailto:jcaniglia@laurel.mt.gov]
Sent: Tuesday, October 05, 2010 2:35 PM
To: Finch, Thomas (PHMSA); Kurt Markegard
Subject:

Tom,

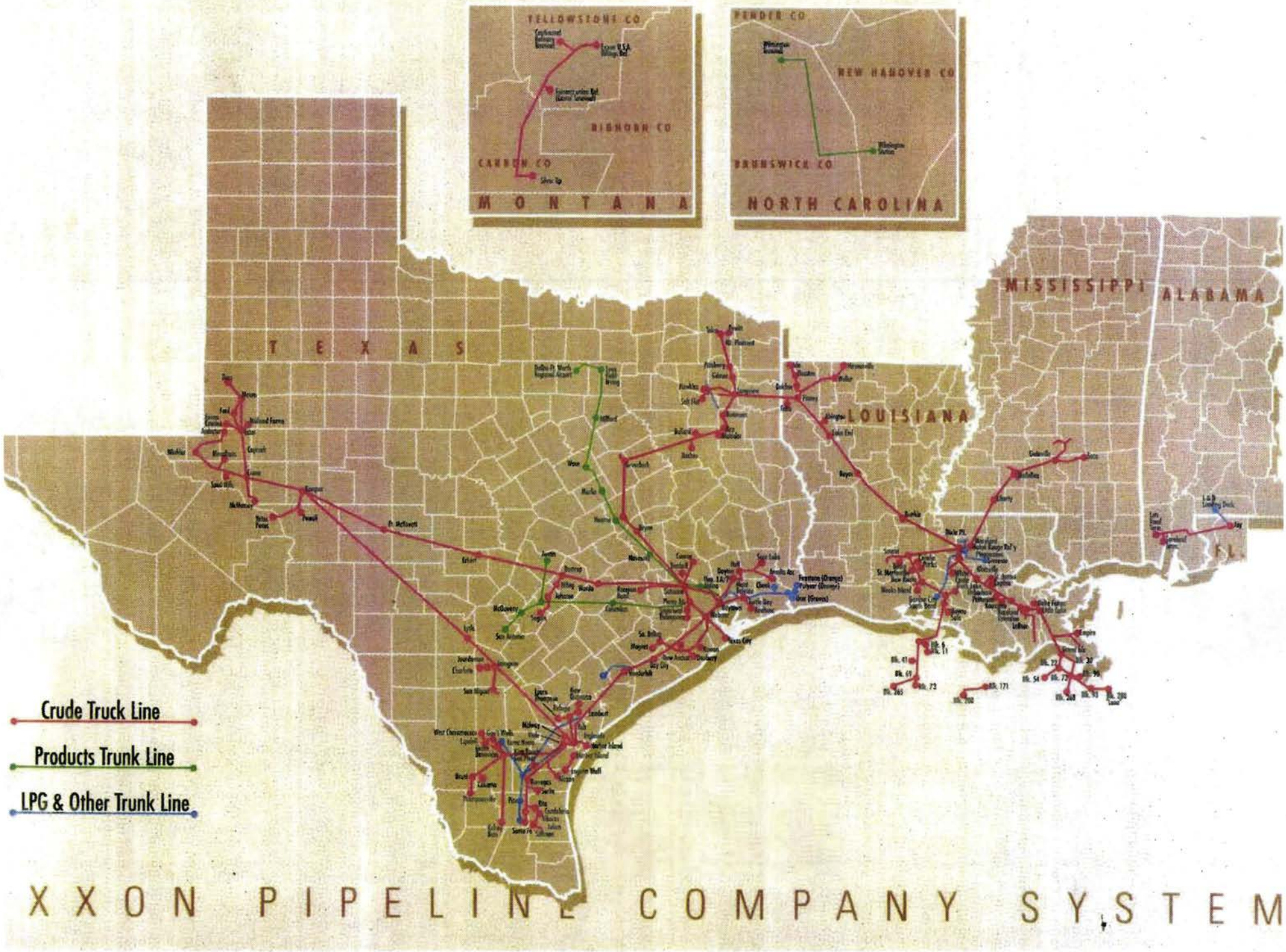
I attached a PDF plat map of Riverside Park. The plat does not show easements for the pipelines and I am not sure if that is an oversight or if there are no easements. Obviously you can tell the pipelines are present from pipeline maps. The links below discuss some of the issues we are dealing with. Please let me know when someone will be able to visit the park and assess the safety issue as it might be helpful for us to be there.

Thanks,

http://billingsgazette.com/news/local/article_23dd4596-c9eb-11df-87ed-001cc4c002e0.html

http://www.laureloutlook.com/articles/2010/06/09/news/big_story/01big.txt

James Caniglia
City Planner
Phone 628-4796 -- Fax 628-2241
P.O Box 10
Laurel, MT. 59044


YELLOWSTONE CO
BIGHORN CO
CARBON CO
MONTANA
PENDER CO
NEW HANOVER CO
BRUNSWICK CO
NORTH CAROLINA
TEXAS
LOUISIANA
MISSISSIPPI
ALABAMA
FL
Crude Truck Line
Products Trunk Line
LPG & Other Trunk Line
XXON PIPELINE COMPANY SYSTEM


PETROLEUM
PIPELINE
EXXON PIPELINE

EXXON PIPELINE COMPANY
POST OFFICE BOX 2220 • HOUSTON, TEXAS 77252-2220

OTTO R. HARRISON
PRESIDENT

Dear Neighbor:

We at Exxon Pipeline Company are **very serious** about safety, and it shows in the way we do business. Our employee safety performance and our record for operational safety are both leaders in the pipeline industry.

We want to keep operating safely, and we need your help.

- **If you receive this booklet at your residence,** Exxon Pipeline Company has a pipeline, or perhaps a number of pipelines, in your neighborhood. Please read this booklet so you will know how to recognize and respond to a pipeline emergency.

- **If you are a company that does excavation work,** please read the section that begins on page 6. It contains information about how you can help avoid emergencies on our pipelines.

- **If you are a public official with responsibility for public safety** or emergency response, please read the section on page 9. It suggests ways that you can help to protect life and property if there is a pipeline emergency in your area.

Each day approximately 25 million barrels of oil and petroleum products are moved through pipelines in this country—safely, quietly, inexpensively, and with minimal intrusion on the environment. With your help, we and other pipeline companies can keep intact this excellent record.

Very truly yours,

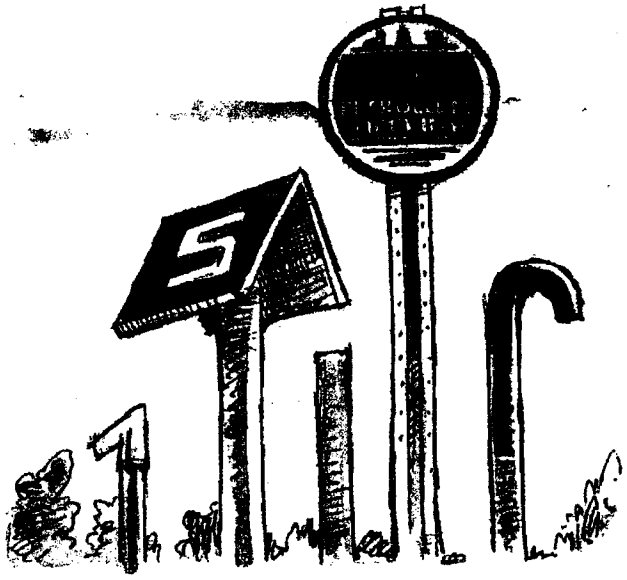


If You Live or Work Near a Pipeline...

How Can You Tell Where a Pipeline is Located?

Since pipelines are buried underground, line markers like the ones shown below are used to indicate their approximate location along the route. The markers can be found where a pipeline intersects a street, highway, or railroad.

The markers display the material transported in the line, the name of the pipeline operator, and a telephone number where the operator can be reached in the event of an emergency.



It is a Federal Crime to Remove or Deface a Pipeline Marker Sign

Pipeline marker signs such as those pictured above are important to public safety. They are so important, in fact, that Congress in 1988 passed a law making it a federal crime for any person to willfully deface, damage, remove, or destroy any pipeline sign or right-of-way marker required by federal law. The penalty for each offense is a fine of up to $5,000, imprisonment for not more than a year, or both.

Are Markers Always Placed on Top of the Pipeline?

Markers indicate the general location of a pipeline. They cannot be relied upon to indicate the exact position of the pipeline they mark. Also, the pipeline may not follow a straight course between markers. And, while markers are helpful in locating pipelines, they are limited in the information they provide. They provide no information, for example, on the depth or number of pipelines in the vicinity.

How Can You Recognize a Pipeline Leak?

Look For	Listen For	Smell
❑ Crude oil or liquid petroleum products on the ground.	❑ A roaring sound.	❑ A pungent odor, sometimes like "rotten eggs."
❑ A dense white cloud or fog.	❑ A hissing sound.	❑ A gasoline-type odor.
❑ A spot of dead vegetation in an otherwise green location may indicate a slow leak.		
❑ Flames (if the leak has ignited).		

Sight, sound, and smell are helpful in detecting pipeline leaks.



What Should You Do If You Suspect a Leak?

Your first concern should be for your personal safety and that of those around you.

❑ Leave the leak area immediately.

❑ Avoid driving into vapor clouds.

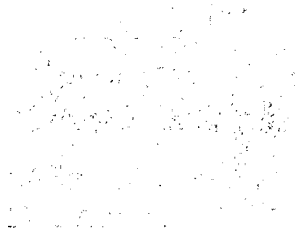
❑ Avoid direct contact with the escaping gas or liquids.

❑ Avoid creating sparks or other sources of heat which could cause the escaping liquids or vapor to ignite and burn. If you find yourself in an area where you suspect hydrocarbon vapors are present, do not light a match, start an engine, or even switch on an electric light.

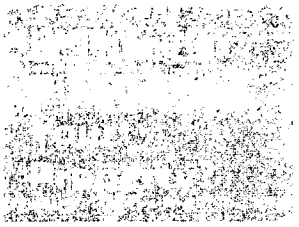
❑ Immediately call your local 911 emergency number, or notify your local fire department, police department, or other public safety officials. Tell them the location and nature of the emergency.

❑ Immediately notify the pipeline operator. Call collect. Give the location, a description of the leak, and your name.

- ❑ Pipelines carry both gaseous and liquid materials.
- ❑ Many liquids form gaseous vapor clouds when released.
- ❑ Many pipelines contain colorless and odorless products.
- ❑ Some pipeline gases are lighter than air and will rise.
- ❑ Other heavier-than-air gases and liquids will stay near the ground and collect in low spots.
- ❑ All petroleum gases and liquids are flammable.
- ❑ Any pipeline leak can be potentially dangerous.

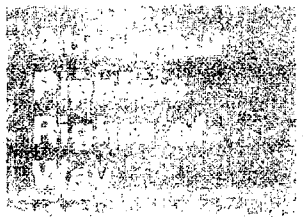


As a property owner, you may not be aware that a pipeline runs through your property. You can be sure by checking your property plat or title report for pipeline easements. Easements are written agreements between pipeline companies and landowners which permit pipeline companies to operate and maintain the pipeline through the landowner's property.

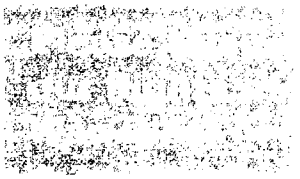


Easements give the pipeline company the right to access the pipeline area or "right-of-way." The pipeline right-of-way must be kept clear of any buildings, structures, or other "encroachments" which could restrict access to the pipeline. Right-of-way easements protect the public and the pipeline.

Pipelines are constructed on land that the pipeline company either owns ("fee land") or on which it holds an easement. A right-of-way agreement is called an easement. Easements provide us with a permanent, limited interest in the land and enable us to operate, test, inspect, maintain, and protect our pipelines.

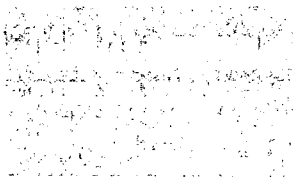


Since we must have ready access to our pipelines at all times, it is important that our rights of way be kept free from obstructions. Don't build, plant, or store anything on the easement. If you would like to utilize our easement for any purpose, be sure to contact us ahead of time at one of the offices shown on the back cover of this booklet.



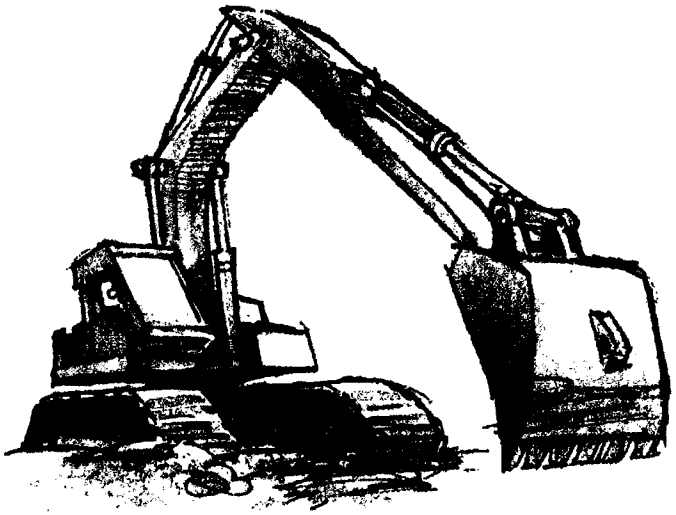


Since our aerial inspectors need a clear view of the ground over our pipelines, we periodically prune trees, shrubs, and vegetation growing over our rights of way.



If You or Your Company Does Excavation Work...

If your company does excavation work, or if you are a homeowner or farmer who occasionally digs on your property, we need your help in preventing pipeline emergencies. Records show that damage from excavation-related activities — particularly equipment digging into pipelines — is the No. 1 cause of pipeline accidents. Without proper coordination, excavation activities in the vicinity of underground pipelines can result in very dangerous situations.



Excavation-related activities — particularly equipment digging into pipelines — is the No. 1 cause of pipeline accidents.

To determine if there are pipelines in the area where excavation is planned, look for pipeline markers at nearby roads, railroads, fences, and streams. Also check the property and deed records. These may show that a pipeline is nearby.

Pipeline markers only show the general area where the pipeline is located. Don't try to guess the route or location of the pipeline from where the markers are placed. That's a gamble no one should take. Call the pipeline company collect at the telephone number shown on the marker. They will send a representative to mark the exact location, route, and depth of the pipeline.

Exxon Pipeline Company Offers "Three Steps to Safety"

Step 1:

Notify Us of a Planned Excavation

Excavators must notify us about their plan to dig near our pipelines, since only excavators know where and when they plan to dig. Give us as much lead time as possible.





Step 2:

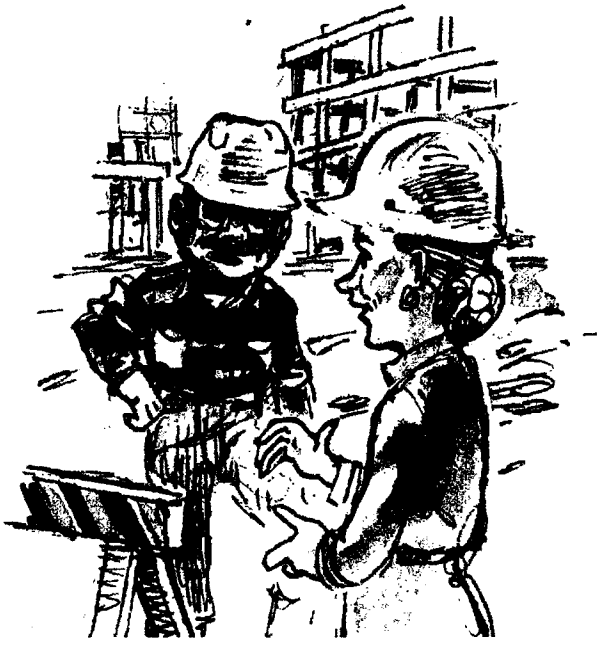
Location and Marking

An Exxon Pipeline Company representative will meet with the excavator to determine if any of our pipelines are nearby. If one of our pipelines is in the excavation area, our representative will provide marking to show the pipeline location, route, and depth. We do this safely, using detailed maps, line finders, and probing rods.

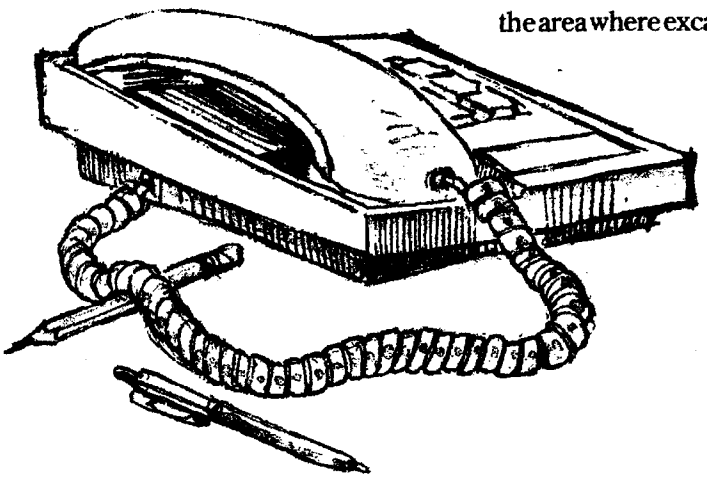
Step 3:

Inspection During and After Excavation

An Exxon Pipeline Company representative will be on the site as necessary during and after excavation to ensure the safety of our pipelines. Our representative will inform the excavator of procedural requirements necessary for the protection of the pipeline. Your cooperation will provide a safe working environment for everyone.



If your area is served by an excavation notification "one-call" center (and most areas are), be sure to call the center and let them know your excavation plans. The center can help expedite the notification of the owners of underground facilities in the area where excavations are planned.

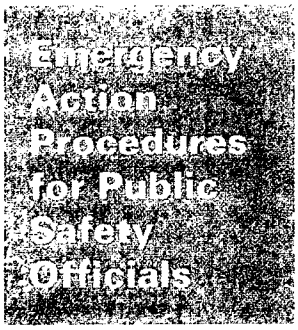


Exxon is a diversified corporation with several affiliated companies. A notification call to one Exxon affiliate will **not** provide notification to other affiliates who might have lines in the excavation area. Each Exxon company has its own marker signs with the company name and telephone number. Treat each affiliate as a totally separate company. Remember: a call to Exxon Pipeline Company will not provide notification to Exxon Company, U.S.A., Exxon Gas Systems, Inc., or Monterey Pipeline Company.

- ❑ Abandon equipment.
- ❑ Leave the area immediately.
- ❑ Warn others.
- ❑ Keep traffic out of the area.
- ❑ Watch for fog or a vapor cloud and move out of its path.
- ❑ Notify public safety officials, such as the local fire and police departments, and tell them the location and nature of the problem.
- ❑ Notify the pipeline company immediately.

If you are digging and disturb a pipeline — even if you cause what seems to be only minor damage to the pipeline — notify the pipeline company immediately. A gouge, scrape, dent, or crease to the pipe or coating may cause a future break or leak. It is imperative that the pipeline owner inspect and repair any damage to the line.

If You Are a Public Safety Official...



If you are a public safety official, you know to take whatever steps you deem necessary to safeguard the public in the event of a pipeline emergency. The following suggestions are offered as a guide:

❑ Secure the area around the leak, to a safe distance. This could include the evacuation of people from homes, businesses, schools, and other locations; the erection of barricades to control access to the emergency site, and similar precautions.

❑ If the pipeline leak is not burning, take steps to prevent ignition. This could include prohibiting smoking, rerouting traffic, and shutting off the electricity and gas supply.

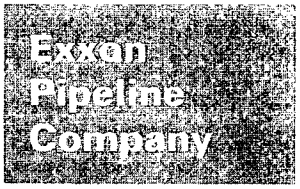
❑ If the pipeline leak is burning, try to prevent the spread of the fire but do not attempt to extinguish it. Burning petroleum products will not explode. If the fire is extinguished, gas or vapor will collect and could explode when reignited by secondary fires.

❑ Contact the pipeline company as quickly as possible. Pipeline marker signs show the pipeline company's name, emergency telephone number, and pipeline contents.





We will immediately dispatch personnel to the site to help handle the emergency, and to provide information to public safety officials to aid in the response to the emergency. We will also take the necessary operating actions — starting and stopping pumps, closing and opening valves, and similar steps — to minimize the impact of the leak. BUT PLEASE: Public safety personnel and others unfamiliar with the pipeline involved in the emergency should not attempt to operate any of the valves on the pipeline. Improper operation of the pipeline valves could make the situation worse and cause other accidents to happen.

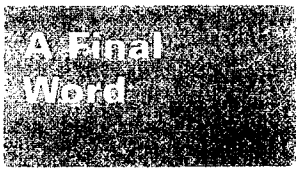


Exxon Pipeline Company (EPC) is a wholly owned subsidiary of Exxon Corporation. The company is a common carrier engaged in the business of transporting crude oil, refined petroleum products, liquefied petroleum gases, and other materials such as chemical feedstocks and industrial gases. We also operate treating plants and salt dome storage facilities at Mont Belvieu, Texas, and Sorrento, Louisiana.

We operate one of the largest pipeline systems in the world — a network of over 9,300 miles of trunk lines and gathering lines in Texas, Louisiana, Mississippi, Alabama, North Carolina, Florida, and Montana. Each day an average of more than 1.1 million barrels of crude oil and products move through our "Lower 48" pipeline systems. We serve approximately 1,450 lease connections in 320 oil and gas fields. We operate 210 pumping stations and provide pipeline transportation services to more than 80 oil producing and chemical companies, large and small.

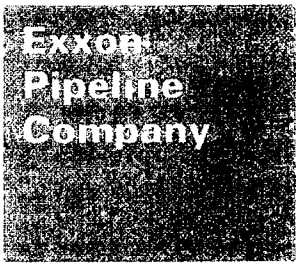
In addition, EPC owns 20.34 percent of the Trans Alaska Pipeline System (TAPS). EPC movements on TAPS average more than 360,000 barrels per day. The company also owns part interests in Plantation Pipeline Company, Dixie Pipeline Company, and several other pipeline systems.

BULK RATE
U.S. POSTAGE
PAID
GRAND PRAIRIE, TX
PERMIT NO. 40



If there is an emergency on an Exxon Pipeline Company pipeline, call 1-800-537-5200 (toll free) or 713/656-1234 (collect).

If you have questions of a general nature about Exxon Pipeline Company, please contact our Public Affairs office at 713/656-5431.



Headquarters

800 Bell Street
P. O. Box 2220
Houston, Texas 77252-2220
713/656-3636

Eastern Division

Baton Rouge Area
18440 Highland Road
P. O. Box 15609
Broadview Station
Baton Rouge, Louisiana 70895-5609
504/755-2800

Longview Area
1202 Morgan Street
P. O. Box 7878
Longview, Texas 75607-7878
903/236-8100

Raceland Area
Highway 308
P. O. Box 218
Raceland, Louisiana 70394-0218
504/537-5211 or 5212

Sunset Area
Highway 182 South
P. O. Drawer H
Sunset, Louisiana 70584-0908
318/662-5233

Central Division

Bayport Area
11005 Fairmont Parkway
La Porte, Texas 77572-1215
713/470-4400

Corpus Christi Area
414 Lantana Street
P. O. Box 4916
Corpus Christ, Texas 78469-4916
512/289-4100

Odessa Area
1 300 West 10th Street
Odessa, Texas 79763-3428
915/334-6500

Luling Area
1234 Highway 183 North
P. O. Box 191
Luling, Texas 78648-0191
210/875-2719

Big Lake Area
P. O. Box 943
Big Lake, Texas 76932-0943
915/334-6584

Satsuma Area
9118 Jack Rabbit Road
Houston, Texas 77095-9118
713/656-2426

U.S. Department
of Transportation
Research and
Special Programs
Administration

Western Region
Pipeline Safety

555 Zang Street
Lakewood, CO 80228

Notice of Amendment

May 3, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

CFF No. 53501-M

Ms. Sue Cummings
Operations Manager
Exxon Pipeline Company
P.O. Box 2220
Houston, TX 77252-2220

Dear Ms. Cummings:

On February 2, 1993, representatives of the Western Region, Office of Pipeline Safety, pursuant to Section 211(c) of the Hazardous Liquid Pipeline Safety Act (HLPSA) (49 U.S.C. 2001 et. seq.) conducted an inspection of Exxon Pipeline Company's (EPC) anti-drug plan and records at your headquarters in Houston, Texas.

As a result of the inspection, it appears that Exxon Pipeline Company has committed probable violations, as noted below, of drug testing regulations, Title 49, Code of Federal Regulations, Part 199. The probable violations are listed below.

1. Section 199.7 requires that the written anti-drug plan contain the methods and procedures for compliance with all the requirements set out in 49 CFR Part 199 and 40.

   EPC's DOT required anti-drug plan is deficient in the following areas:

   a) §199.9(a) Use of persons who fail or refuse a drug test.

   EPC's plan does not address what action is to be taken if an individual failed a drug test after returning to duty.

b) §199.15(d)(2) Review of drug testing results.

EPC's plan does not indicate that the MRO is to refer an individual to an employee assistance program or to a personnel or administrative officer if there is no legitimate medical reason for a confirmed positive test.

c) §40.25(f)(3) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address instructing the collection site person to contact the proper authority if an individual fails to arrive at the assigned time.

d) §40.25(f)(9) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address allowing the use of a public rest room in the event that an employer-designated collection site is not accessible and there is an immediate requirement for specimen collection (e.g., circumstances require a post accident test).

e) §40.25(f)(11) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address allowing donors to wash his/her hands after submitting a specimen.

f) §40.25(f)(15) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address forwarding suspected adulterated specimens to the lab.

g) §40.25(f)(16) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address providing for same gender collection site person to collect a second sample under direct observation whenever there is reason to believe a particular individual has altered or substituted a specimen.

h) §40.25(f)(20) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan has no procedures for donor to initial the identification label on the specimen bottle.

i) §40.25(f)(24) Specimen collection procedures-Integrity and identity of specimen.

EPC's plan does not address the requirement that the collection site person must appropriately safeguard specimens during temporary storage.

j) §40.31(d)(7)&(8) Employer Blind Performance Test Procedures.

EPC's plan does not address false positive issues regarding blind specimens.

k) §40.33(b)(3) Medical Review Officer--Qualifications and Responsibilities.

EPC's plan does not indicate that the MRO shall not consider the results of tests not obtained or processed in accordance with 49 CFR Part 40.

l) §40.33(d) Verification for Opiates; Review for Prescription Medication.

EPC's plan does not address opiate verification.

m) §40.33(e) Reanalysis Authorized.

EPC's plan does not address authorized reanalysis.

This letter serves to provide you with the notice of the inadequate procedures and the response options as prescribed under §199.7(b). The operator is allowed thirty (30) days after receipt of such notice to submit written comments or request an informal hearing. After considering the material presented, the Office of Pipeline Safety is required to notify the operator of the required amendment or withdraw the notice proposing the amendment. If you do not desire to contest the notice, please provide this office with the revised Anti-drug Plan within 30 days of receipt of this notice.

Sincerely,

Edward J. Ondak
Regional Director

Enclosure

UNITED STATES DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
HAZARDOUS LIQUID PIPELINE SAFETY VIOLATION REPORT

1. Inspector Name	2. Date of Inspection	3. CPF#					
Peter J. Katchmar	February 2, 1993		5 M	3	5	0	1

4. Pipeline Operator/Owner
Exxon Pipeline Company (EPC)

5a. Headquarters Address
P.O. Box 2220
Houston, TX 77252-2220

5b. Telephone No.
(713)656-3636

6. Inspection Location
800 Bell
Houston, TX 77002-7426

7. Inspection Unit
No. 1 of 1

8. Portion of System Inspected (Describe location & facility)
Headquarters Drug Inspection

9. Nature and Size of System

Number of Miles _____

Commodities Transported _____

Relevant Details with Respect to System _____

10. Nature of Probable Violations (Check as many as applicable)

____ 1. Problem in Design/Materials
____ 2. Problem in Construction
____ 3. Reporting Requirements
____ 4. Test Requirements
____ 5. Personnel Qualifications and Training
_X_ 6. Anti-drug Program (more than 50 employees)
____ 7. Other Operations
____ 8. Corrosion Control
____ 9. Pressure Control
____ 10. Other Maintenance/Monitoring
____ 11. Inadequate Procedures
____ A. Construction ____ D. Training
____ B. Corrosion Control ____ E. Maintenance
____ C. Operations

RSPA Form HLPS 101989

Violation No. 1

11a. CFR § Violated: §199.9

11b. Summarize what the regulation requires that operator did not do:

§199.9 (a) An operator may not knowingly use as an employee any person who--

(1) Fails a drug test required by this part and the medical review officer makes a determination under §199.15(d)(2);

EPC's plan does not address what action is to be taken if an individual failed a drug test after returning to duty.

12. Provide detailed information about violation:

EPC's plan does not address what action is to be taken if an individual failed a drug test after returning to duty.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: Terry F. Bowie **Title:** EPC/Human Resources

14b. Comments of person interviewed:

Continuation Sheet
Violation No. 2

11a. CFR § Violated: §199.15(d)(2)

11b. Summarize what the regulation requires that operator did not do:

§199.15 (d) MRO DETERMINATIONS. The following rules govern MRO determinations:

(2) If the MRO determines, after appropriate review, that there is no legitimate medical explanation for the confirmed positive test result other than the unauthorized use of a prohibited drug, the MRO shall refer the individual tested to an employee assistance program, or to a personnel or administrative officer for further proceedings in accordance with the operator's anti-drug program.

EPC's plan does not indicate that the MRO is to refer an individual to an employee assistance program or to a personnel or administrative officer if there is no legitimate medical reason for a confirmed positive test.

12. Provide detailed information about the violation:

EPC's plan does not indicate that the MRO is to refer an individual to an employee assistance program or to a personnel or administrative officer if there is no legitimate medical reason for a confirmed positive test.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 3

11a. CFR § Violated: §40.25(f)(3)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(3) If the individual fails to arrive at the assigned time, the collection site person shall contact the appropriate authority to obtain guidance on the action to be taken.

EPC's plan does not address instructing the collection site person to contact the proper authority if an individual fails to arrive at the assigned time.

12. Provide detailed information about the violation:

EPC's plan does not address instructing the collection site person to contact the proper authority if an individual fails to arrive at the assigned time.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 4

11a. CFR § Violated: §40.25(f)(9)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(9) In the exceptional event that an employer-designated collection site is not accessible and there is an immediate requirement for specimen collection (e.g., circumstances require a post accident test), a public rest room may be used according to the following procedures: A collection site person of the same gender as the individual shall accompany the individual into the public rest room which shall be made secure during the collection procedure. If possible, a toilet bluing agent shall be placed in the bowl and any accessible toilet tank. The collection site person shall remain in the rest room, but outside the stall, until the specimen is collected. If no bluing agent is available to deter specimen dilution, the collection site person shall instruct the individual not to flush the toilet until the specimen is delivered to the collection site person. After the collection site person has possession of the specimen, the individual will be instructed to flush the toilet and to participate with the collection site person in completing the chain of custody procedures.

EPC's plan does not address allowing the use of a public rest room in the event that an employer-designated collection site is not accessible and there is an immediate requirement for specimen collection (e.g., circumstances require a post accident test).

12. Provide detailed information about the violation:

EPC's plan does not address allowing the use of a public rest room in the event that an employer-designated collection site is not accessible and there is an immediate requirement for specimen collection (e.g., circumstances require a post accident test).

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 5

11a. CFR § Violated: §40.25(f)(11)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(11) After the specimen has been provided and submitted to the collection site person, the individual shall be allowed to wash his or her hands.

EPC's plan does not address allowing donors to wash his/her hands after submitting a specimen.

12. Provide detailed information about the violation:

EPC's plan does not address allowing donors to wash his/her hands after submitting a specimen.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 6

11a. CFR § Violated: §40.25(f)(15)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(15) All specimens suspected of being adulterated shall be forwarded to the laboratory for testing.

EPC's plan does not address forwarding suspected adulterated specimens to the lab.

12. Provide detailed information about the violation:

EPC's plan does not address forwarding suspected adulterated specimens to the lab.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 7

11a. CFR § Violated: §40.25(f)(16)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(16) Whenever there is reason to believe that a particular individual has altered or substituted the specimen as described in paragraph (e)(2)(i) and (iii) of this section, a second specimen shall be obtained as soon as possible under the direct observation of a same gender collection site person.

EPC's plan does not address providing for same gender collection site person to collect a second sample under direct observation whenever there is reason to believe a particular individual has altered or substituted a specimen.

12. Provide detailed information about the violation:

EPC's plan does not address providing for same gender collection site person to collect a second sample under direct observation whenever there is reason to believe a particular individual has altered or substituted a specimen.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 8

11a. CFR § Violated: §40.25(f)(20)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(20) The individual shall initial the identification label on the specimen bottle for the purpose of certifying that it is the specimen collected from him or her.

EPC's plan has no procedures for donor to initial the identification label on the specimen bottle.

12. Provide detailed information about the violation:

EPC's plan has no procedures for donor to initial the identification label on the specimen bottle.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 9

11a. CFR § Violated: §40.25(f)(24)

11b. Summarize what the regulation requires that operator did not do:

§40.25(f) INTEGRITY AND IDENTITY OF SPECIMEN. Employers shall take precautions to ensure that a urine specimen is not adulterated or diluted during the collection procedure and that information on the urine bottle and on the urine custody and control form can identify the individual from whom the specimen was collected. The following minimum precautions shall be taken to ensure that unadulterated specimens are obtained and correctly identified:

(24) The urine specimen and chain of custody form are now ready for shipment. If the specimen is not immediately prepared for shipment, the collection site person shall ensure that it is appropriately safeguarded during temporary storage.

EPC's plan does not address the requirement that the collection site person must appropriately safeguard specimens during temporary storage.

12. Provide detailed information about the violation:

EPC's plan does not address the requirement that the collection site person must appropriately safeguard specimens during temporary storage.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 10

11a. CFR § Violated: §40.31(d)(7)&(8)

11b. Summarize what the regulation requires that operator did not do:

§40.31(d) EMPLOYER BLIND PERFORMANCE TEST PROCEDURES.

(7) Should a false positive error occur on a blind performance test specimen and the error is determined to be an administrative error (clerical, sample mixup, etc.), the employer shall promptly notify the DOT agency concerned. The DOT agency and the employer shall require the laboratory to take corrective action to minimize the occurrence of the particular error in the future, and, if there is reason to believe the error could have been systemic, the DOT agency may also require review and reanalysis of previously run specimens.

(8) Should a false positive error occur on a blind performance test specimen and the error is determined to be a technical or methodological error, the employer shall instruct the laboratory to submit all quality control data from the batch of specimens which included the false positive specimen to the DOT agency concerned. In addition, the laboratory shall retest all specimens analyzed positive for that drug or metabolite from the time of final resolution of the error back to the time of the last satisfactory performance test cycle. This retesting shall be documented by a statement signed by the individual responsible for day-to-day management of the laboratory's urine drug testing. The DOT agency concerned may require an on-site review of the laboratory which may be conducted unannounced during any hours of operation of the laboratory. Based on information provided by the DOT agency. DHHS has the option of revoking or suspending the laboratory's certification or recommending that no further action be taken if the case is one of less serious error in which corrective action has already been taken, thus reasonably assuring that the error will not occur again.

12. Provide detailed information about the violation:

EPC's plan does not address false positive issues regarding blind specimens.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 11

11a. CFR § Violated: §40.33(b)(3)

11b. Summarize what the regulation requires that operator did not do:

§40.33(b) MEDICAL REVIEW OFFICER-- QUALIFICATIONS AND RESPONSIBILITIES.

(3) The role of the MRO is to review and interpret confirmed positive test results obtained through the employer's testing program. In carrying out this responsibility, the MRO shall examine alternate medical explanations for any positive test result. This action may include conducting a medical interview and review of the individual's medical history, or review of any other relevant biomedical factors. The MRO shall review all medical records made available by the tested individual when a confirmed positive test could have resulted from legally prescribed medication. The MRO shall not, however, consider the results or urine samples that are not obtained or processed in accordance with this part.

EPC's plan does not indicate that the MRO shall not consider the results of tests not obtained or processed in accordance with 49 CFR Part 40.

12. Provide detailed information about the violation:

EPC's plan does not indicate that the MRO shall not consider the results of tests not obtained or processed in accordance with 49 CFR Part 40.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 12

11a. CFR § Violated: §40.33(d)

11b. Summarize what the regulation requires that operator did not do:

§40.33(d) VERIFICATION FOR OPIATES; REVIEW FOR PRESCRIPTION MEDICATION.
Before the MRO verifies a confirmed positive result for opiates, he or she shall determine that there is clinical evidence--in addition to the urine test--of unauthorized use of any opium, opiate, or opium derivative (e.g., morphine/codeine). (This requirement does not apply if the employer's GC/MS confirmation testing for opiates confirms the presence of 6-monocetylmorphine.)

EPC's plan does not address opiate verification.

12. Provide detailed information about the violation:

EPC's plan does not address opiate verification.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

Continuation Sheet
Violation No. 13

11a. CFR § Violated: §40.33(e)

11b. Summarize what the regulation requires that operator did not do:

§40.33(e) REANALYSIS AUTHORIZED.
Should any question arise as to the accuracy or validity of a positive test result, only the Medical Review Officer is authorized to order a reanalysis of the original sample and such retests are authorized only at laboratories certified by DHHS. The Medical Review Officer shall authorize a reanalysis of the original sample if requested to do so by the employee within 72 hours of the employee's having received actual notice of the positive test. If the retest is negative, the MRO shall cancel the test.

EPC's plan does not address authorized reanalysis.

12. Provide detailed information about the violation:

EPC's plan does not address authorized reanalysis.

See No. 15

13. Public and/or environmental concerns in area of violation:

14a. Person Interviewed: None **Title:**

14b. Comments of person interviewed: None

15. Supporting Documents/Materials

Item No.	Description (Include date)	Source of Documents	Remarks
1	DOT Anti-drug Plan 49 CFR Part 199 and Part 40 for Exxon Pipeline Company: Revised January 1993	Exxon Pipeline Company	None
2	Part 199 and Part 40 HQ Inspection Form: Dated February 2, 1993	OPS Personnel	None

16. **Inspector's Signature:** **Date:**

Peter J. Katchmar

April 23, 1993

17. Compliance History

Date	Place	Describe Violation/ Noncompliance	CPF No. Date WL	Outcome
		NONE!!!		

18. Gravity of Offense

This violation is considered significant.

19. Degree of Culpability

Exxon Pipeline Company had apparent intent to meet the DOT regulations.

20. Ability to Continue in Business

Excellent

21. Ability to Pay

Excellent

22. Good Faith in Attempting to Achieve Compliance

Good

23a. Proposed Remedy

_____	Warning Letter
_____	Civil Penalty: Recommended Amount $ _____
_____	Compliance Order
_____	Hazardous Facility Order
X	Notice of Amendment of O&M Plan

23b. Analysis of Proposed Remedy

24. Regional Director's Signature: Date:

Jl Qverly for
Edward J. Ondak

April 23, 1993

U.S. Department of Transportation
Office of Pipeline Safety
Western Region

EXHIBIT TAB

Name of Operator Exxon Pipeline Company

Exhibit No. 1

Evidence	Obtained from	Identifying Witness
DOT Anti-drug Plan 49 CFR Part 199 and Part 40: Revised January 1993	Exxon Pipeline Company	Peter J. Katchmar

Investigator Name Peter J. Katchmar Title Engineer

U.S. Department of Transportation
Office of Pipeline Safety
Western Region

EXHIBIT TAB

Name of Operator Exxon Pipeline Company

Exhibit No. 2

Evidence	Obtained from	Identifying Witness
Part 199 and Part 40 HQ Drug Inspection Form: Dated: February 2, 1993	OPS Personnel	Peter J. Katchmar

Investigator Name Peter J. Katchmar Title Engineer

DOT/RSPA
OFFICE OF
WESTERN REGION
555 ZANG ST.

EXXON PIPELINE COMPANY
POST OFFICE BOX 2220 • HOUSTON, TEXAS 77252-2220

SUE CUMMINGS
OPERATIONS MANAGER

Certified Mail-Return Receipt Requested
May 28, 1993

Notice of Amendment
Revised Anti-Drug Plan

Mr. Edward J. Ondak
Regional Director
Western Region Office Of Pipeline Safety
U. S. Department Of Transportation
555 Zang Street
Lakewood, Colorado 80228

Dear Mr. Ondak:

Enclosed is the revised Anti-Drug Plan for Exxon Pipeline Company (EPC). Revisions have been made pursuant to your letter (dated May 3, 1993) received by us on May 6, 1993. We have addressed each of the probable violations listed in your letter and have revised EPC's plan accordingly as follows:

Probable Violation	EPC Revision
1.a.	Page 8, ¶ 4. C.
1.b.	Page 12, ¶ 7. D. 2.
1.c.	Page 22, Appendix D #4
1.d.	Page 23, Appendix D #11
1.e.	Page 23, Appendix D #14
1.f.	Page 24, Appendix D #18
1.g.	Page 24, Appendix D #16
1.h.	Page 24, Appendix D #23
1.i.	Page 25, Appendix D #28 & 29
1.j.	Page 10 ¶ 6. B.3
1.k.	Page 11 ¶ 7. B.2.(f)
1.l.	Page 12 ¶ 7. D.1.
1.m.	Page 13 ¶ 7. F.

We request that you issue a letter of compliance after review and consideration of the revisions. If you have questions or need additional information, please call Joseph H. Fitts at (713) 656-5153.

Sincerely,

J. M. Betzold
for Sue Cummings

SC:JHF:afa
Enclosure

DOT ANTI-DRUG PLAN
49 CFR PART 199 AND PART 40

FOR

EXXON PIPELINE COMPANY

Revised: May 1993

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1. Scope and Compliance

Exxon Pipeline Company is committed to providing a safe, healthy and productive workplace. The company recognizes that substance abuse by an individual performing work can have an adverse effect upon one's ability to perform and can expose the individual, fellow workers, the public and company to risk.

Exxon Pipeline Company's policy also recognizes the significant threat that a drug-impaired "employee", as defined in 49 CFR Part 199, working in the pipeline industry can pose to the safety of coworkers and the general public. In order to address the safety threat presented by the problem of drug abuse in the pipeline industry, the Department of Transportation, Research and Special Programs Administration, has established rules and regulations requiring drug testing under certain circumstances. Exxon Pipeline Company has developed and adopted its Anti-Drug Plan, effective April 20, 1990, (revised 5/93) to specify the circumstances under which these drug testing methods and procedures would apply in compliance with 49 CFR Part 199 and Part 40.

2. Definitions

A. An accident is defined as an incident reportable under Part 191 involving gas pipeline facilities or LNG facilities, or an accident reportable under Part 195 involving hazardous liquid pipeline facilities. An accident is further defined under Post-accident testing in this Plan.

B. An employee means a person who performs on a pipeline or LNG facility an operating, maintenance, or emergency-response function regulated by 49 CFR Part 192, 193 or 195 of the DOT pipeline safety regulations (covered position). The person may be employed directly by the operator, or by a contractor engaged by the operator, or be employed by the contractor. This includes subcontractors and anyone employed by a subcontractor.

Appendix A contains the covered positions that are subject to drug testing as outlined in the Plan.

Employees who are or may be subject to the provisions of this Plan will be notified and provided with details and/or a copy of the Plan. Exxon Pipeline Company will make copies of the Plan available to employees at the Division Offices upon request.

C. An operator means a person or business entity who owns or operates pipeline facilities subject to 49 CFR Part 192, 193 or 195.

D. A contractor means any individual or business entity with whom the Pipeline Operator contracts to perform operating, maintenance or emergency-response functions, as regulated by 49 CFR Part 192, 193 or 195, on the Operator's pipeline or LNG facility as an independent contract.

E. The Drug Program Manager is responsible for recordkeeping and coordination of the Plan. (See Appendix E.)

1. The Designated Management Official will be a supervisory level employee at the Division level who is responsible for the local coordination of this Plan.

F. Passing a drug test means that the initial testing or confirmation testing under DOT procedures does not show evidence of the presence of a prohibited drug in the employee's or applicant's system.

G. Failing a drug test means that the confirmation test result shows positive evidence of the presence under DOT procedures of a prohibited drug in the employee's or applicant's system.

H. Refusing to submit to a drug test means any employee or applicant who: 1) refuses to take a required drug test; 2) without a legitimate reason fails to report to the collection site; 3) without a medical reason fails to provide an adequate specimen; or 4) fails to cooperate with the collection process at the collection site under the Department of Transportation regulations.

I. Drugs to be tested or prohibited drugs are any of the following substances:

	THRESHOLD LEVELS	
DRUG	SCREEN	CONFIRMATION
Marijuana (THC)	100 ng/ml	15 ng/ml
Cocaine	300 ng/ml	150 ng/ml
Opiates	300 ng/ml	300 ng/ml
Amphetamines	1000 ng/ml	500 ng/ml
Phencyclidine (PCP)	25 ng/ml	25 ng/ml

3. Drug Tests Required

A. Pre-employment Testing

All applicants for initial employment or subsequent reemployment in covered positions (see Appendix A Covered Positions) must successfully pass a pre-employment drug test prior to working in a covered position for Exxon Pipeline Company or must be covered by an Anti-Drug Plan which conforms to Department of Transportation Regulations 49 CFR Parts 40 and 199. All applicants will be notified, at the time they complete a job application, that they will be required to submit to a drug test if they are considered otherwise qualified for employment and that they will be subject to the terms and conditions of this Plan if they are ultimately hired.

All current employees transferring or being transferred from a non-covered position to a covered position must successfully pass a pre-employment drug test prior to assuming a covered position. The Pipeline Operator may not use any employee hired by a pipeline contractor who does not pass a pre-employment drug test in conformance with 49 CFR Parts 40 and 199.

B. Post-accident Testing

As soon as possible, but no later than 32 hours after an accident, Exxon Pipeline Company will test each employee or supervisor, whose performance either contributed to an accident or cannot be completely discounted as a contributing factor to the accident.

All reasonable steps will be taken to obtain a urine specimen from an employee after an accident. In the case of a conscious but hospitalized employee, Exxon Pipeline Company will request that the hospital or medical facility obtain a specimen, following proper chain-of-custody and, if necessary, Exxon Pipeline Company will refer the hospital or medical facility to the Department of Transportation Drug Testing Requirements provided in 49 CFR Parts 40 and 199.

If an employee is unconscious and otherwise unable to evidence consent to a post-accident drug test, after the employee's condition is stabilized, the hospital or medical facility will collect a specimen in compliance with the chain-of-custody and guidelines provided in 49 CFR Parts 40 and 199, and the hospital or medical facility will retain the specimen, preferably in frozen storage, until the employee has regained consciousness.

If an employee who is subject to post-accident testing is conscious, able to urinate normally (in the opinion of a medical professional) and refuses to be tested, under 49 CFR Part 199.9, that employee shall be removed from the covered position and shall be subject to disciplinary action, including termination.

If the employee's test result is negative, then the employee may return to work in a covered position at the discretion of Exxon Pipeline Company.

Exxon Pipeline Company may decide not to conduct a post-accident drug test if the best information available immediately after the accident indicates that the employee's performance could not have contributed to the accident or that, because of the time between the performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use.

For purposes of this Plan, an accident on a gas pipeline or LNG facility is defined as one of the following:

1. An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from LNG facility and

   a. A death, or personal injury necessitating inpatient hospitalization; or

   b. Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

2. An event that results in an emergency shutdown of an LNG facility.

3. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2).

An accident on a hazardous liquid pipeline is defined as follows:

1. Any 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. Loss of 50 or more barrels of liquid.

   c. Escape to the atmosphere of more than five barrels a day of highly volatile liquids.

   d. Death of any person.

   e. Bodily harm to any person resulting in one or more of the following:

      i. Loss of consciousness.

      ii. Necessity to carry the person from the scene.

      iii. Necessity for medical treatment.

      iv. Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.

   f. Estimated property damage to the property of the operator or others, or both, exceeding $5,000.

C. Random Testing

All employees who perform work in a covered position will be subject to random testing at any time with no advance notice. The random selection process will ensure each employee the same fair and equal chance of being selected.

To assure the selection process is random, all employees covered under this Plan will be placed in a common pool. Employees have the potential of being selected for random testing by an anonymous, objective selection criteria (computer based random selection software program) on a daily basis (program selects random testing day and employee).

Random drug testing is spread through the 12 month period and will be administered at an annual rate of at least 50 percent of the total pool of employees.

Employees need not be drug tested who are not scheduled to work that day, including those who are on scheduled vacation or have reported in sick.

Since each random sampling selects from the total pool of employees, it is conceivable that an employee could be tested more than once a year. The random selection procedure will pick the employee's name and social security number. This procedure will be conducted by Exxon's Health Service Department Substance Abuse Testing Control Unit (SATCU), 800 Bell, Houston, TX 77252. Once the selection procedure has been completed, SATCU will submit this information via computer terminal to the Drug Program Manager.

The Drug Program Manager will notify the Designated Management Official of the name(s) of employee(s) selected to be tested. Employee(s) will be sent to approved collection facility within 20 minutes plus travel time of being notified that they have been randomly selected for a drug test.

D. Reasonable Cause Testing

An employee will be tested when Supervisor(s) determine that there is reasonable cause to believe that a specific employee is using a prohibited drug. For this purpose, reasonable cause is defined as a reasonable and articulable belief that the employee is using a prohibited drug, which belief is based upon specific and contemporaneous physical, behavioral, or performance indicators of probable drug use.

A test based upon reasonable cause will involve at least two supervisors, one of which is trained in the detection of probable drug use, who will substantiate and concur in the decision that a test is necessary. If it is impossible for two supervisors to observe, substantiate and concur in the decision to test, only one supervisor need witness the behavior.

All supervisors have received training under the Employee Assistance Program in detection of possible drug use symptoms which substantiates the decision to test the employee for reasonable cause.

A report describing the employee's condition and other operational circumstances will be made to the Drug Program Manager and other Exxon Pipeline Company management, as appropriate.

In any reasonable cause circumstance, the Designated Management Official, of Exxon Pipeline Company will transport the employee to an approved collection facility and await the completion of the collection procedure. The Designated Management Official will then transport the employee back to Exxon Pipeline Company premises. Exxon Pipeline Company will contact a taxi or family member to transport the employee home. If the employee refuses to agree to any of these procedures and attempts to operate a vehicle,

Exxon Pipeline Company will make appropriate efforts to discourage the employee from doing so, up to and including contacting local law enforcement officials. Any employee failing to cooperate with any of these procedures described above will be subject to disciplinary action, including termination.

While waiting for an employee's drug test results, the employee will be removed from the covered position until the drug test results are confirmed negative for prohibited drugs. If the employee cannot be placed in a non-covered position during this time, the employee will be off work with pay.

If the employee tests negative, the employee may return to work in a covered position at Exxon Pipeline Company's discretion.

E. Post-rehabilitation Testing

An employee who returns to work after completing a rehabilitation program will be drug tested under Exxon Pipeline Company's After-Care Program. Such tests will be conducted for no longer than sixty (60) months after an employee has returned to work. The schedule, for such testing will be determined by the Medical Review Officer (MRO). In no case shall an employee be allowed to return to work without successfully passing a DOT drug test.

4. Persons Who Fail/Test Positive or Refuse to Test

A. Any employee of Exxon Pipeline Company, contractor, an employee of the contractor, or a subcontractor of the contractor who fails a drug test required under this Plan which is confirmed as positive by the Medical Review Officer will not work in a covered position and will be subject to disciplinary action, including termination, and to conditions outlined in this Plan.

B. Any employee who refuses to take a required drug test, refuses to provide a specimen at the collection site, refuses to cooperate during the collection process, refuses to complete any relevant documentation, such as the Custody and Control Form or any other paperwork, fails to properly cooperate with collection site personnel, engages in any conduct which creates reason to believe a urine specimen has been altered or substituted, fails to report to the collection site without a legitimate reason, and fails to provide an adequate specimen without a medical basis will be removed from the covered position and subject to disciplinary action, including termination.

C. Any employee who tests positive in a return to duty or follow up drug test will be removed from the covered position and is subject to disciplinary action, including termination.

5. Employee's Right-to Request Retest of Specimen

If the MRO determines that there is no legitimate medical explanation for a confirmed positive test result other than the unauthorized use of a prohibited drug, the original specimen must be retested if the employee makes a written request within sixty (60) days from the date of the final test results from the MRO.

In the case of applicants, the retest (a second test of the same sample) must be requested in writing within sixty (60) calendar days from the date of the final test results from the MRO. If the retest is negative, Exxon Pipeline Company will reimburse the applicant for the cost of the retest, and will reconsider employment of applicants who were previously rejected solely on the basis of the test result.

If the employee requests retesting by a second laboratory, original laboratory will follow approved custody and control procedures for transportation of the specimen.

6. Testing Method

A. Selection Collection Procedures

Any person requested to undergo a drug test will be required to provide a urine specimen at a designated collection site approved by Exxon Pipeline Company (see Appendix B). In order to ensure integrity of the specimen collection procedure, a standard Custody and Control Form will be used. This form shall be completed by the employee and collection site personnel. The form will be completed by the person responsible for collecting the urine specimen and will be forwarded along with the urine specimen to the designated National Institute on Drug Abuse (NIDA) certified laboratory, which will conduct the drug analysis.

The laboratory will then forward a copy of the Custody and Control Form to the Medical Review Officer, who will review it when analyzing any positive test results. Exxon Pipeline Company (SATCU) will retain a copy of the Custody and Control Form for each drug test it conducts. The chain-of-custody portion of the Custody and Control Form must be completed by every person who handles or otherwise comes into contact with the urine specimen.

The employee specimen collection procedures that ensure specimen integrity, individual privacy, security and proper transportation of the specimen are contained in Appendix D.

B. Laboratory Analysis

1. Certified laboratory

All urine specimens to be tested for the presence of prohibited drugs must be analyzed by the NIDA laboratory certified under the Department Health & Human Services (DHHS) Mandatory Guidelines for Federal Workplace Drug Testing Programs. All drug tests required by Exxon Pipeline Company will therefore be shipped for analysis to the laboratory listed in Appendix E.

The certified laboratory permitted inspection by Exxon prior to being awarded a testing contract, and will permit, at any time, unannounced inspections, including examination of records, by Exxon, the Administrator or the representative of any state agency that has jurisdiction over Exxon Pipeline Company.

2. Reporting Results

Before the laboratory reports a test result, it will first review the results of the initial test, confirmatory test or any relevant quality

control data to certify that the test result is accurate. The laboratory will then report the test results to Exxon Pipeline Company's MRO within five (5) working days after the receipt of the specimen and will also forward the original Custody and Control Forms to the MRO.

Any specimen which was negative on an initial or confirmatory test will be reported as negative. The only specimens reported as positive will be those which have been confirmed as positive through gas chromatography/mass spectrometry. Test results will not be reported verbally by telephone. Additionally, the laboratory will not report any test results to Exxon Pipeline Company, but only to its MRO via electronic transfer. The laboratory and Exxon Pipeline Company will ensure that the data transmission is confidential and will secure and limit access to its data transmission storage and retrieval system.

The MRO may request quantitative test results from the laboratory. After interviewing the individual, the MRO will report to Exxon Pipeline Company's Drug Program Manager whether the test is positive or negative and may also report the identity of the drug(s) for which there was a positive result. The MRO will not, however, disclose the quantitative test results to Exxon Pipeline Company unless such disclosure is necessary in a lawsuit, grievance or other proceeding initiated by or on behalf of the employee arising from a verified positive drug test.

3. Quality Assurance

Quarterly, 100 blind specimens are sent to the Certified Laboratory for analysis. These specimens are packaged like all Exxon Pipeline Company specimens that the laboratory receives. Eighty percent (80%) of the specimens are negative; however, twenty percent (20%) of the specimens are spiked with the five drugs for which Exxon Pipeline Company is testing as identified in this Plan. Each spiked specimen generally contains only one drug at a level close to the DOT threshold, but some spiked specimens contain two drugs. A false positive result by the laboratory must be reported to DOT, and Exxon Pipeline Company will require the laboratory to take corrective action to minimize the occurrence of the particular error in the future. If the false positive error is determined to be a technical or methodological error, Exxon Pipeline Company will instruct the laboratory to submit all quality control data from the batch of specimens which included the false positive specimen to DOT and request a retest of all specimens analyzed positive for that drug or metabolite from the time of final resolution of the error back to the time of the last satisfactory performance test cycle. All retests shall be signed and documented by responsible laboratory management.

7. Medical Review Officer (MRO)

A. Qualifications

All confirmed positive test results will be reported by the laboratory to a Medical Review Officer (MRO) prior to any decision regarding an employee's qualification for continued employment due to the results of a drug test. The MRO is a licensed physician with knowledge of substance abuse disorders. The MRO will review and consider possible alternative medical explanations for the positive test result, as well as the chain-of-custody to ensure that it is complete and sufficient. Exxon Pipeline Company's MRO is listed in Appendix E.

B. MRO Duties

The MRO will perform the following functions for Exxon Pipeline Company:

1. Review the results of drug testing before they are reported to Exxon Pipeline Company.

2. Review and interpret each confirmed positive test result to determine if there is an alternative medical explanation for the confirmed positive test result by:

   a. Conducting a medical interview with the individual tested.

   b. Reviewing the individual's medical history and any relevant biomedical factors.

   c. Reviewing all medical records made available by the individual tested to determine if a confirmed positive test resulted from legally prescribed medication.

   d. Requiring, if necessary, that the original specimen be reanalyzed to determine the accuracy of the reported test results.

   e. Verifying that the laboratory report and assessment are correct.

   f. The MRO will not consider the results or urine specimens that are not obtained or processed in accordance with procedures under 49 CFR Part 40.

3. Determine whether and when an employee who refused to take or did not pass a drug test administered under DOT procedures may be returned to duty.

4. Determine a schedule of unannounced follow-up testing, in consultation with Exxon Pipeline Company, for an employee who has returned to duty as part of the After-Care Program.

5. Ensure that an employee has been drug tested in accordance with the DOT procedures before the employee returns to duty.

C. Action on positive test results

Prior to making a final decision to verify a positive test result for an individual, the MRO will give the individual an opportunity to discuss the test result. The MRO will contact the individual directly, on a confidential basis, to determine whether the individual wishes to discuss the test result. A staff person under the MRO's supervision may make the initial contact and a medically licensed or certified staff person may gather information from the individual. Except as provided below, the MRO will talk directly with the individual before verifying a test as positive.

If unsuccessful, after making and documenting all reasonable efforts to contact the individual, the MRO will contact Exxon Pipeline Company's Drug Program Manager, who will direct the individual to contact the MRO as soon as possible. If it becomes necessary to reach the individual through the Drug Program Manager, the Manager will utilize procedures to ensure that the individual contact with the MRO is held in confidence.

The MRO may verify a test as positive without having communicated directly with an individual about the results in three circumstances:

1. If the individual expressly declines the opportunity to discuss the test.

2. If the Drug Program Manager has successfully made and documented contact with the individual and instructed the individual to contact the MRO, and more than five (5) days have passed since the individual was successfully contacted.

3. In other circumstances provided for in DOT drug testing regulations.

   If a test is verified as positive because of an individual's failure to contact the MRO, the individual will have the opportunity to provide the MRO with evidence documenting that serious illness, injury or other circumstances unavoidably prevented timely contact with the MRO. The MRO, on the basis of such information, may reopen the verification and allow the individual to present information concerning a legitimate explanation for the confirmed positive test. If the MRO concludes that there is a legitimate explanation, the MRO will declare the test to be negative.

D. MRO Determinations

1. The MRO will determine that there is clinical evidence, in addition to the urine test, of unauthorized use of any opium, opiate or opium derivative (e.g., morphine and codeine) before a test is verified as a positive for opiates . (This requirement does not apply if the employer's GC/MS confirmation testing for opiates confirms the presence of 6-monoacetylmorphine.)

2. If the MRO determines, after appropriate review, that there is no legitimate medical explanation for the confirmed positive test result other than the unauthorized use of a prohibited drug, the MRO shall confirm and report the test as positive to the Drug Program Manager who will, in turn, refer the employee tested for further disciplinary action (including termination) and to an Employee Assistance Program in accordance with the Anti-Drug Plan.

3. If the MRO determines, based upon review of the laboratory inspection reports, quality assurance and quality control data, and other drug test results, that a particular drug test result is scientifically insufficient for further action, the MRO will conclude that the test is negative.

E. Disclosure of Information

The MRO will not disclose to any third party medical information provided by the individual as a part of the testing verification process, except as provided below:

1. The MRO may disclose such information to Exxon Pipeline Company, a Federal agency or a physician responsible for determining the medical qualification of the employee under an applicable DOT regulation, as applicable, only if:

   a. An applicable DOT regulation permits or requires disclosure.

   b. In the MRO's reasonable medical judgment, the information could result in the employee being determined to be medically unqualified under a DOT rule.

   c. In the MRO's reasonable medical judgment, in a situation in which there is no DOT rule establishing physical qualification standards applicable to the employee, the information indicates that continued performance by the employee in a covered position could pose a significant safety risk.

F. Authorized Reanalysis

Only the MRO may order a reanalysis of the original specimen. The Medical Review Officer shall authorize a reanalysis of the original sample if requested to do so by the employee within 72 hours of employee's having received actual notice of the positive test. (Also, see paragraphs 5 and 8. B.) Such retests shall be authorized only at NIDA certified laboratories. If the retest is negative, the MRO will consider the test to be cancelled.

8. Retention of Specimens and Retesting

A. Retention of Specimens

Specimens that yield positive results on confirmation will be retained by the laboratory in properly secured, long-term frozen storage for at least 365 days as required by DOT procedures. Within this 365-day period, the employee or his representative, Exxon Pipeline Company, the Department of Transportation Administrator, or state agency may request that the laboratory retain the specimen for an additional period. If, within the 365-day period, the laboratory has not received a proper written request to retain the specimen for a further reasonable period specified in the request, the specimen may be discarded following the end of the 365-day period.

B. Retesting the Specimen

If the MRO determines there is no legitimate medical explanation for a confirmed positive test result other than the unauthorized use of a prohibited drug, the original specimen must be retested if the employee or applicant for employment makes a written request for retesting within 60 days of receipt of the final test result from the MRO. The employee or applicant for employment may specify retesting by the original laboratory or by a second laboratory certified by the Department of Health and Human Services. The retest will be at the employee's or applicant employment expense, unless the retest is negative, at which time the employee will be reimbursed for costs.If retesting is done by a second laboratory, the original laboratory must follow approved chain-of-custody procedures in transferring the specimen.

Since some analytes may deteriorate during storage, detected levels of the drug below detection limits established in the DOT procedures, but equal to or greater than the established sensitivity of the assay, must, as technically appropriate, be reported and considered corroborative of the original positive results.

9. Employee Program

A. Education

Exxon Pipeline Company will provide an education program for its employees, which will include the following:

1. Informational materials will be distributed in training classes and will be displayed on field bulletin boards.

2. Community service hot-line telephone numbers for employee assistance will be distributed in training classes and will displayed on field bulletin boards. (see Appendix C)

3. Exxon Pipeline Company's Plan and/or Plan details regarding the use of prohibited drugs will be distributed in training classes and displayed on field bulletin boards.

B. Training

All supervisory personnel responsible for determining whether an employee must be drug tested based on reasonable cause will be required to complete at least one 60-minute period of training on the specific contemporaneous physical, behavioral and performance indicators of probable drug use.

All supervisors and employees on an ongoing basis are given educational training sessions as part of their safety meetings. These training sessions instruct in chemical dependency, and give a brief synopsis of the drug testing procedure and drug awareness.

C. Substance-Abuse-Assistance

In addition to the education and training program described above, Exxon Pipeline Company also has available an employee assistance program which employees may use for additional consultation and referral for assistance in remaining drug-free. The Exxon Health Advisory Program (EHAP) is administered by Human Affairs International listed below.

Human Affairs International
4550 Post Oak Place
Suite 213
Houston, TX 77027
(800) 624-6185

10. Contractor Employees

Exxon Pipeline Company is responsible for ensuring that its contractors and subcontractors meet the requirements of 49 CFR Part 199, Part 40, and are in compliance with, and have implemented the following procedures:

Contractor employees and subcontractors who perform operations, maintenance and emergency response functions are required by contract to maintain a written anti-drug plan, conduct drug testing, and implement EAP education and training as required by 49 CFR Part 199.

Contractors are required to sign contracts with language consistent with maintaining a drug-free workplace, this also establishes Exxon Pipeline Company's right to perform unannounced audits of contractors' anti-drug plans, allows access to property and records by Exxon Pipeline Company, the Administrator, the jurisdictional state agency or a representative of the state agency.

All contractors in covered positions are monitored using a combination of auditing methods, including review of anti-drug plan/policy, collecting test results and reviewing plan administration information and conducting onsite visits to ensure compliance.

To demonstrate that contractors are in compliance with contract provisions and DOT regulations, test results of their testing program as well as other program components are submitted for review and analysis. Random onsite audits are also conducted. Onsite checklists are used to evaluate contractor compliance and reports are kept for further follow-up if necessary.

11. Recordkeeping

Exxon Pipeline Company's Program Manager (see Appendix E) will keep the following records for the periods specified.

Records which demonstrate that the collection process conforms to 49 CFR Parts 40 and 199 will be kept for at least three (3) years.

Records of employee drug test results that show that an employee failed a drug test, and the type of test failed (e.g., post-accident), and records that demonstrate rehabilitation, if any, will be kept for at least five (5) years, and will include the following information:

1. The functions performed by employees who failed the drug test.

2. The prohibited drugs which were used by employees who failed the drug test.

3. The disposition of employees who failed the drug test (e.g., termination, leave without pay).

4. The age of each employee who failed the drug test.

Records of employee drug test results that show employees passed a drug test will be kept for at least one (1) year.

A record of the number of employees tested, by type of test (e.g., post-accident), will be kept for at least five (5) years.

Records confirming that supervisors and employees have been trained as required under this Plan will be kept for at least three (3) years.

Exxon Pipeline Company will maintain an annual summary of records relating to the administration and results of the drug tests it performs. This summary will include the total number of drug tests administered; the number of drug tests administered in each category; the total number of positive results; the total number of positive results per test category; the disposition of each person who tested positive; the number of tests performed by a laboratory that indicated evidence of a prohibited drug or metabolite which lead to a confirmatory test; the total number of tests resulting in a confirmed positive result which was reported to the MRO; the total number of tests resulting in a confirmed positive by drug category.

12. Confidentiality

A. Information regarding an individual's drug test results will only be released upon the written consent of the employee, except that such information must be released to the DOT Administrator or the representative of a State agency upon request as part of an accident investigation.

B. Statistical data related to drug testing that is not name-specific and training records must be made available to the DOT Administrator or the representative of a State agency, upon request.

C. Any employee who is the subject of a drug test conducted under this Plan shall, upon written request, have access to any records relating to the drug test and any records relating to the results and analysis.

D. To maintain confidentiality, written requests regarding the individual's drug use will be stored in secure files. The employee's drug testing records will not be made a part of the employee's personnel file.

Signed: _____
Exxon Pipeline Company
Drug Program Manager

APPENDIX A

COVERED POSITIONS

Senior Technician A
Senior Technician B
Senior Technician C
Technician A
Technician B
Technician C
Assistant Technician A
Assistant Technician B
Assistant Technician C
Assistant Technician Trainee (12 mos)
Senior Engineering Technician
Engineering Technician A
Engineering Technician B
Engineering Technician C

Field Pipeline Engineers
Technologist/Engineer
Controllers
Tech Leader
Welder
Managers/Supervisors
Regulatory Analyst
Field Human Resources Specialist

APPENDIX B

DRUG TEST COLLECTION SITES

STATE: Florida

E.M.S.I. 3920 Monteigne Drive Pensacola, FL 32504	Main Phone: (904) 434-6168 Other Phone: (904) 435-4385- Pager	Hours of Operation: 8:00 a.m. - 5:00 p.m. Monday - Friday 24 hrs. - seven days a week for emergencies

STATE: Louisiana

Baton Rouge General Hospital 3600 Florida Boulevard Baton Rouge, LA 70806	Main Phone: (504) 387-7600 Other Phone:	Hours of Operation: 24 hours a day Seven days a week
EUSA Medical Services-Baton Rouge 4045 Scenic Highway Baton Rouge, LA 70805	Main Phone: (504) 359- 8571 Other Phone:	Hours of Operation: 7:00a.m. - 3:30p.m. Monday - Friday
Hill Medical Associates 170 McGehee Baton Rouge, LA 70815	Main Phone: (504) 272-3246 Other Phone:	Hours of Operation: 7:30a.m. - 6:00p.m. Monday - Friday
SECON 260 Rue France Lafayette, LA 70508	Main Phone: (318) 235-3712 Other Phone: (800) 256-3741	Hours of Operation: 8:00a.m. - 5:00p.m. Monday - Friday
Family Doctor Clinic Ill Acadia Drive Raceland, LA 70394	Main Phone: (504) 537-7575 Other Phone:	Hours of Operation: 8:00a.m. - 5:00p.m. Monday - Friday
E.M.S.I. 521 E. Washington Shreveport, LA 71104	Main Phone: (318) 868-2719 Other Phone:	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday

STATE: Mississippi

E.M.S.I. 2600 Insurance Center Dr. Suite 205 Jackson, MS 39216	Main Phone: (601) 362-6716 Other Phone:	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday

APPENDIX B (Cont'd)

DRUG TEST COLLECTION SITES

STATE: Montana

EUSA Health Services Billings Refinery Medical Department 700 Exxon Road Billings, MT 59101	Main Phone: 406) 657-5215 Other Phone:	Hours of Operation: 7:30a.m. - 4:30p.m. Monday - Friday

STATE: North Carolina

E.M.S.I. 3173 Wrightsville Avenue Wilmington, NC 28403	Main Phone: 919) 799-2075 Other Phone:	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday

STATE: Texas

EUSA Health Services - Baytown 2800 Decker Drive Baytown, TX 77520	Main Phone: (713)425-3310 Fax: (713) 425-7950	Hours of Operation: 9:00a.m. - 11:00a.m. 1:00p.m. - 3:00p.m. Monday - Friday
APC Nurse Placement 1224 3rd Street, Suite #2-A Corpus Christi, TX 78404	Main Phone: (512) 887-8040 Other Phone:	Hours of Operation:
E.M.S.I. 1111 West Mockingbird Ln. Suite #701 Dallas, TX 75247	Main Phone: (214) 689-3640 Other Phone:	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday
N.W. Allergy Clinic 12130 Greenspoint Drive Houston, TX 77060	Main Phone: (713) 872-9999 Other Phone:	Hours of Operation: 9:00a.m.-5:00p.m.(M,T,TH) 2:00a.m.-6:30p.m.(W) 9:00a.m.-2:00p.m.(F)
EUSA Health Services - Headquarters 800 Bell Street, Suite 3180 Houston, TX 77002	Main Phone: (713) 656-3424 Other Phone:	Hours of Operation: 7:30a.m. - 4:30p.m. Monday - Friday

APPENDIX B (Cont'd)

DRUG TEST COLLECTION SITES

Odessa Internal Medicine Associates 506 North Alleghaney Odessa, TX 79761	Main Phone: (915) 337-5411 Other Phone: (915) 332-9313	Hours of Operation: 8:00a.m. - 5:00p.m. Monday - Friday
Forward Edge, Incorporated 2750 Strawberry Pasadena, TX 77502	Main Phone: (713) 920-1335 Other Phone:	Hours of Operation: 7:30a.m. - 4:30p.m. Monday - Friday
E.M.S.I. 4335 Piedras Drive West, Suite #207 San Antonio, TX 78228	Main Phone: (512) 734-5001 Other Phone: (512) 230-0532	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday
E.M.S.I. 1405 South Fleishel, Suite #332 Tyler, TX 75701	Main Phone: (214) 595-3673 Other Phone:	Hours of Operation: 8:30a.m. - 4:30p.m. Monday - Friday
Hillcrest Medical Center *Bellmead 3400 Bellmead Drive Waco, TX 76705	Main Phone: (817) 799-0241 Other Phone: (817) 753-0908	Hours of Operation: 8:00a.m. - 5:00p.m. Monday - Friday

APPENDIX C

BULLETIN BOARD POSTING

EMPLOYEE ASSISTANCE PROGRAMS

In accordance with U.S. Department of Transportation regulations 49 CFR Part 199.19 Employee Assistance Programs and the Federal Drug-Free Workplace Act of 1988, listed below are the names and phone numbers of some community service organizations that offer substance abuse programs or information.

NAME	TELEPHONE NUMBER
National Institute Drug Abuse Help Line	800-843-4971
The National Drug Information and Treatment Hotline	800-662-HELP (4357)
Cocaine Anonymous	800-COCAINE
Al-Anon	800-356-9996
American Council on Alcoholism Help Line	800-527-5344
LOCAL ASSISTANCE	
Employee Health Advisory Program (EHAP)	800-624-6185

APPENDIX D

Collection Procedures

1. To deter the dilution of specimens at the collection site, toilet bluing agents will be placed in toilet tanks wherever possible so the reservoir of water in the toilet bowl always remains blue. Wherever practicable, there shall be no other sources of water (e.g., no shower or sink) in the enclosure where urination occurs. If there is another source of water in the enclosure, it shall be effectively secured or monitored to ensure it is not used (undetected) as a source for diluting the specimen.

2. The collection site should have a clean flat surface for paperwork.

3. Upon arriving at the collection site, the individual to be tested shall present the collection site person with proper identification to ensure that he/she is positively identified as the person selected for testing (e.g., by presenting a driver's license or other photo ID, or by identification by the Designated Management Official). If the individual's identity cannot be established, the collection site person shall not proceed with the collection and Exxon Pipeline Company shall be notified. If the employee requests, the collection site person shall show his/her identification to the employee.

4. If the individual to be tested fails to arrive at the collection site at the assigned time, the collection site person shall contact Designated Management Official to obtain guidance on the action to be taken. Failure to report for a urine test at the assigned time may result in termination of employment, or disqualification from further consideration for employment.

5. The individual to be tested will be required to remove any unnecessary outer garments (e.g., a coat or jacket) that might conceal items or substances that could be used to tamper with or adulterate the urine specimen. The collection site person will ensure that all outer belongings such as purses or briefcases remain with the outer garments. The individual may retain his/her wallet. If the employee requests it, the collection site person shall provide the employee with a receipt for any personal belongings.

6. Before the collection process begins, the individual shall provide the collection site person with a Custody and Control Form if it has not been previously forwarded to the site by Exxon Pipeline Company.

7. The individual shall be instructed to wash and dry his/her hands prior to urination.

8. After washing his/her hands, the individual shall remain in the presence of the collection site person and shall not have access to any water fountain, faucet, soap dispenser, cleaning agent, or any other materials which could be used to adulterate the specimen.

9. The individual may provide his/her specimen in the privacy of a stall or otherwise partitioned area that allows for individual privacy. The collection site person shall provide the individual with a specimen bottle or container, if appropriate, for this purpose.

10. The collection site person shall note any unusual behavior or appearance on the Custody and Control Form.

11. In the exceptional event that Exxon Pipeline Company's designated collection site is not accessible and there is an immediate requirement for a specimen collection (e.g., an accident investigation), a public rest room may be used according to the following procedures: A collection site person of the same gender as the individual shall accompany the individual into the public rest room, which shall be made secure during the collection procedure. If possible, a toilet bluing agent shall be placed in the bowl and any accessible toilet tank. The collection site person shall remain in the rest room, but outside the stall, until the specimen is collected. If no bluing agent is available to deter specimen dilution, the collection site person shall instruct the individual not to flush the toilet until the specimen is delivered to the collection site person. After the collection site person has possession of the specimen, the individual will be instructed to flush the toilet and to participate with the collection site person in completing the chain-of-custody procedures.

12. Upon receiving the specimen from the individual, the collection site person shall determine if it contains at least 60 milliliters of urine. If the individual is unable to provide 60 milliliters of urine, the collection site person shall direct the individual to drink fluids and, after a reasonable time, again attempt to provide a complete specimen using a fresh specimen bottle (and fresh collection container, if used). The original specimen shall be discarded. If the employee is still unable to provide a complete specimen, the following rules apply:

    a. In the case of a post-accident test or test for reasonable cause (as defined by the DOT regulations), the employee shall remain at the collection site and continue to consume reasonable quantities of fluids until the specimen has been provided or until the expiration of a period up to eight (8) hours from the beginning of the collection procedure.

    b. In the case of a pre-employment test, random test, follow-up test, or any other test not for cause (as defined by the DOT regulations), Exxon Pipeline Company may elect to proceed as specified in Paragraph (a) (consistent with any applicable restrictions on hours of service), or may elect to discontinue the collection and conduct a subsequent collection at a later time.

    c. If the employee cannot provide a complete specimen within the 8 hour period, or at the subsequent collection, as applicable, then the MRO shall refer the individual for a medical evaluation to develop pertinent information concerning whether the individual's inability to provide a specimen is genuine or constitutes a refusal to provide a specimen. (In pre-employment testing, if Exxon Pipeline Company does not wish to hire the individual, the MRO is not required to make such a referral.) Upon completion of the examination, the MRO shall report his/her conclusions to Exxon Pipeline Company in writing.

13. No portion of any specimen collected under these procedures may be used for any purpose other than drug testing required under DOT regulations.

14. After the specimen has been provided and submitted to the collection site person, the individual shall be allowed to wash his/her hands.

15. Immediately after the specimen is collected, the collection site person shall measure the temperature of the specimen. The temperature measuring device used must accurately reflect the temperature of the specimen and not contaminate the specimen. The time from urination to temperature measurement is critical and in no case shall exceed four (4) minutes.

16. Whenever there is reason to believe that a particular individual has altered or substituted the specimen because (a) the temperature of a specimen is outside the range of 32.5 C-37.7 C/90.5 F-99.8 F, or (b) the collection site person observes conduct clearly and unequivocally indicating an attempt to substitute or adulterate the sample (e.g. substitute urine in plain view, blue dye in specimen presented, etc.) another specimen shall be obtained as soon as possible under direct observation of a collection site person of the same gender and both specimens shall be forwarded to the laboratory for testing. An individual may volunteer to have his/her oral temperature taken to provide evidence to counter the reason to believe the individual may have altered or substituted the specimen caused by the specimen's temperature falling outside the prescribed range.

17. Immediately after the specimen is collected, the collection site person shall also inspect the specimen to determine its color and look for any signs of contaminants. Any unusual findings shall be noted on the Custody and Control Form.

18. All specimens suspected of being adulterated shall be forwarded to the laboratory for testing.

19. Whenever there is reason to believe that a particular individual has altered or substituted the specimen, a second specimen shall be obtained as soon as possible under the direct observation of a same gender collection site person.

20. Prior to requiring any individual to provide another urine specimen under direct observation because of circumstances constituting reason to believe the specimen may have been altered or substituted, the collection site person shall first contact a higher level supervisor or Exxon Pipeline Company's Designated Management Official to review and concur in advance with the decision to require observation.

21. After the urine specimen is provided, both the individual being tested and the collection site person shall keep the specimen in view at all times prior to its being sealed and labeled. The specimen shall be sealed (by placement of a tamperproof seal over the bottle cap and down the sides of the bottle) and labeled in the presence of the employee. If the specimen is transferred to a second bottle, the collection site person shall request the individual to observe the transfer of the specimen and the placement of the tamperproof seal over the bottle cap and down the sides of the bottle.

22. The collection site person, in the presence of the individual, shall place securely on the bottle an identification label which contains the date, the individual's specimen number, and any other identifying information provided or required by Exxon Pipeline Company. If separate from the label, the tamperproof seal shall also be applied.

23. The individual shall, in the presence of the collection site person, initial the identification label on the specimen bottle for the purpose of certifying that it is the specimen collected from him/her.

24. The collection site person shall, in the presence of the individual, enter on the Custody and Control Form all information identifying the specimen. The collection site person shall sign the Custody and Control Form certifying that the collection was accomplished according to the instructions provided, and to indicate receipt of the specimen from the employee.

3. The last urine specimen provided by the donor (i.e., on a previous occasion) was determined by the laboratory to have a specific gravity of less than 1.003 and a creatinine concentration below .2 g/1.

4. The donor has previously been determined to have a controlled substance without medical authorization and the particular test was being conducted under a DOT agency regulation providing for follow-up testing upon or after return to service.

If (1) or (2) occur, a second collection under direct observation must be conducted before the individual departs the collection site. If (3) or (4) occurs, it is an employer option to conduct subsequent collections under direct observation. The collection site person must obtain concurrence in advance from his/her supervisor or Exxon Pipeline Company's Designated Management Official before a directly observed collection is conducted. All observed collections must have a collection site person of the same gender as the individual.

APPENDIX E

Drug Program Manager:

Terry Bowie, Human Resources Manager

Laboratory:

Nichols Institute Substance Abuse Testing (NISAT)
7470-A Mission Valley Road
San Diego, CA 92108
(800) 446-4728

Medical Review Officers:

K. J. Gould, Jr., M.D.
Health Services Department Room 3180
800 Bell
Houston, TX 77002-7426
(713) 656-3704

Richard O. Dockins, M.D.
Exxon Baton Rouge Refinery
Room 104
4045 Scenic Highway
Baton Route, LA 70805-4860
(504) 359-8406

John L. Schaller, M.D.
Exxon Baytown Refinery
Room NW-17
2800 Decker Drive
Baytown, TX 77520-2099
(713) 425-3310

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

Western Region,
Pipeline Safety

555 Zang Street
Lakewood, CO 80228

September 28, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

CPF No. 53501-M

Ms. Sue Cummings
Operations Manager
Exxon Pipeline Company
P.O. Box 2220
Houston, TX 77252-2220

Dear Ms. Cummings:

On June 2, 1993, the Western Region, Office of Pipeline Safety received your revised anti-drug plan. The plan has been reviewed and it has been determined that Exxon has satisfactorily addressed the items in the Notice of Amendment.

Sincerely,

Jack C. Overly for

Edward J. Ondak
Regional Director

U.S. Department
of Transportation
**Research and
Special Programs
Administration**

Western Region
Pipeline Safety

12600 W. Colfax Avenue
Suite A-250
Lakewood, CO 80215-3736

NOTICE OF PROBABLE VIOLATION
PROPOSED COMPLIANCE ORDER
AND
NOTICE OF AMENDMENT

CERTIFIED - RETURN RECEIPT REQUESTED

2 Copies / Date 2-11-03
Sent To Compliance Registry

January 30, 2003

A. K. Turner
VP Operations
ExxonMobil Pipeline Company
Room 697-D
800 Bell Street
Houston, Texas 77002

CPF No. 5-2003-5006

Dear Mr. Turner:

During October 8-10 and November 21, 2002, a representative of the Western Region, Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of ExxonMobil's facilities in south central Montana, and manuals, and records in Bridger, Montana.

As a result of the inspection, it appears that you have committed probable violations as noted below of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies. (a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.**

Records indicate that ExxonMobile completed their 2001 Procedural Manual review on May 25, 2001. A letter to the Railroad Commission of Texas dated September 11, 2002 asserts that a new Procedural Manual was to become effective in October 2002. Between May 25, 2001 and October 2002 there was no review of the existing Procedural Manual which exceeds the requirement that a company review its procedural manual once each calendar year not to exceed 15 months.

2. **§195.402 Procedural manual for operations, maintenance, and emergencies. (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:**

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

ExxonMobil's CP monitoring procedures do not reference or use the monitoring criteria in NACE Standard RP0169-96 as required in §195.571. Specifically ExxonMobil's procedure does not have provisions for considering voltage drops. ExxonMobil must amend their procedures to include CP monitoring criteria as listed in NACE Standard RP0169-96 paragraphs 6.2 and 6.3.

3. **§195.571 What criteria must I use to determine the adequacy of cathodic protection? Cathodic protection required by this subpart 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 Standard RP0169-96 (incorporated by reference, see Sec. 195.3).**

CP monitoring records show that voltage drops are not being considered, as required in NACE Standard RP0169-96 paragraphs 6.2 and 6.3 when annual cathodic pipe to soil potentials are being taken. ExxonMobil is using the criteria of -850 mV with the impressed cathodic protection current on and uninterrupted. RP0169-96 only allows the use of a -850 mV criteria after voltage drops have either been accounted for or deducted.

Under 49 United States Code, §60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to this violations, we will take enforcement action when and if the continued violation comes to our attention.

Regarding Item 2, as provided in 49 CFR §190.237, this notice serves as your notification that this office considers your procedures/plans inadequate. Under 49 CFR §190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or a request for a hearing within 30 days after receipt of this notice. After reviewing

the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 CFR §190.237. If you do not wish to contest this notice, please provide your revised procedures within 30 days of receipt of this notice. When appropriate procedures have been prepared, submit them to:

Director, Western Region
Office of Pipeline Safety
Research and Special Programs Administration
12600 West Colfax Avenue, Suite A-250
Lakewood, Colorado 80215.

Regarding Item 3, pursuant to 49 United States Code §60118, the Office of Pipeline Safety proposes to issue to ExxonMobil a compliance order in the form of the Proposed Compliance Order that is attached to and made a part of this Notice of Probable Violation. Also, attached is a description of the response options available to you.

Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights under 49 CFR §190.209. A response which does not contest the allegations in the Notice authorizes the Associate Administrator, Office of Pipeline Safety to find the facts to be as alleged herein and to issue an appropriate compliance order.

In addition we hope that you will consider and address these two items of concern to further improve your present level of safety. If you have any questions regarding this matter please contact me at (303) 231-5701.

Concern: ExxonMobile completed a API 653 out of service inspection of their Tank 319 (1 of 5 tanks at Silver Tip, Montana) on August 25, 1997. That inspection found an area in the floor of the tank that had a remaining thickness of .100 inch. This was the newer of the tanks and as such probably had the least amount of under floor corrosion. Table 4-1 of API 653 calls for inspection of a tank bottom when the predicted bottom plate thickness is .100 inch. Because of the age of the remaining 4 tanks it can be assumed that these tanks also have floor areas with a remaining thickness of .100 inch or less. Interviews with ExxonMobile indicate that the remaining 4 tanks have been budgeted to be taken out of service for inspection/repair in the next 4 years (one per year). OPS strongly supports ExxonMobil's effort to complete the inspection/repair of these remaining breakout tanks within the next 4 years.

Concern: Results from the high resolution MFL tool show approximately 112 external metal loss anomalies on the top side of the pipeline between 10 to 30% of the wall thickness. There is a high probability that some or all of these anomalies are associated with mechanical damage. A few of these anomalies are located next to girth welds and some are located next to long seams. OPS suggests that ExxonMobile run a geometry

tool in the near future to determine if the top side metal loss anomalies are associated with denting.

Please refer to CPF No. 5-2003-5006 in any correspondence or communication on this matter.

Sincerely,

Chris Hoidal
Director

Enclosure

Proposed Compliance Order

Pursuant to 49 United States Code §60118, the Office of Pipeline Safety proposes to issue to ExxonMobil a compliance order incorporating the following requirements to assure the compliance of ExxonMobil with the pipeline safety regulations applicable to its Montana pipeline operations.

1. In regard to Item No. 3 of the Notice pertaining to cathodic protection monitoring practices:

   ExxonMobil must initiate CP monitoring practices that consider all voltage drops at each test station, as required in NACE Standard RP0169-96 paragraphs 6.2 and 6.3.

2. ExxonMobil must provide to the Office of Pipeline Safety, Western Region, the cost of implementing compliance for Item 1 above.

3. Within 60 days of issuance of the Final Order, ExxonMobil must accomplish the above items.

Provide to the Office of Pipeline Safety, Western Region, the cost of implementing the above listed item.

When appropriate procedures and associated costs have been prepared, submit them to:

Director, Western Region
Office of Pipeline Safety
Research and Special Programs Administration
12600 West Colfax Avenue, Suite A-250
Lakewood, Colorado 80215.

UNITED STATES DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
HAZARDOUS LIQUID PIPELINE SAFETY VIOLATION REPORT

1. **Inspector Name** Jerry Davis	2. **Date of Inspection** 10/8-10 & 11/21/2002	3. **CPF#**					

4. Pipeline Operator/Owner
ExxonMobil Pipeline Company

5a. Headquarters Address 800 Bell Street, Houston, TX 77002	**5b. Telephone No.** (713)656-3926
6. Inspection Location South central Montana, Bridger, MT	**7. Inspection Unit No.** 1 **of** 1

8. Portion of System Inspected (Describe location & facility)
Various locations along ROW, Silver Tip and Bridger PS and Billings Ref.

9. Nature and Size of System

Number of Miles 69

Commodities Transported Crude Oil

Relevant Details with Respect to System Impressed CP system

10. Nature of Probable Violations (Check as many as applicable)

____ 1. Problem in Design/Materials
____ 2. Problem in Construction
____ 3. Reporting Requirements
____ 4. Test Requirements
____ 5. Personnel Qualifications and Training
____ 6. Anti-drug Program
____ 7. Other Operations
✓ 8. Corrosion Control
____ 9. Pressure Control
✓ 10. Other Maintenance/Monitoring
✓ 11. Inadequate Procedures
____ A. Construction
✓ B. Corrosion Control
____ C. Operations
____ D. Training
____ E. Maintenance

RSPA Form HLPS 101989

Violation No. 1

11a. CFR § Violated: §195.402(a)

11b. Summarize what the regulation requires that operator did not do:
The operator is required to review their operating, maintenance and emergency procedures once each calendar year not to exceed 15 months.

12. Provide detailed information about violation:
Review of records ExxonMobil maintains for compliance to Part 195 revealed that Exxon Mobil did not review their procedures from May of 2001 until the issuance of their revised manual in October of 2002, a time period of approximately 17 months. This violation is not considered to be a major concern but the operator must be prudent in the future to insure that operations and maintenance personnel are provided with procedures that reflect new regulation as well as changes to the system itself.

13. Public and/or environmental concerns in area of violation:
ExxonMobil's efforts to revise their procedures manual to address past OPS concerns resulted in ExxonMobil inadvertence missing the review date of their procedures that were in effect. The oversight resulted in ExxonMobil exceeding the required review period by 2 months. Though not serious at this time this violation could lead to operational problems if the time period were substantially longer. Such problems could lead to releases that have the potential affect all lands and waters this pipeline crosses.

14a. Person Interviewed: Records **Title:** _____

14b. Comments of person interviewed:

Continuation Sheet
Violation No. 2

11a. CFR § Violated: §195.402(c)(3)

11b. Summarize what the regulation requires that operator did not do:
This section requires that the operator have procedures for all operation and maintenance activities that have requirements in Part 195. §195.571, the monitoring requirement of the new corrosion rule, requires that the operator use NACE Standard RP0169-96 paragraphs 6.2 and 6.3 for specific cathodic protection (CP) monitoring requirements. RP0169-96 requires that voltage drops be considered when taking CP monitoring readings.

12. Provide detailed information about the violation:
ExxonMobil's CP monitoring procedures does not have a method of considering voltage drops as required in NACE Standard RP0169-96. ExxonMobil must amend their CP monitoring procedures to insure that voltage drops are considered.

FYI: When a CP monitoring reading is taken the potential (voltage) between the reference cell and the pipe determines if there is adequate protection against corrosion. Voltage drops are caused from current (I) passing through the earth (R)adjacent to the pipeline. Voltage=Current(I) X Resistance(R). While a CP rectifier is operating there is current passing from the anode, the ground bed, to the cathode, the pipe. The volt meter cannot discern the difference between potential voltage and IR voltage. If current is not interrupted the meter reads the combination of IR voltage and potential voltage thus possibly making the reading appear larger than the potential reading alone. Therefore it is important that there be a method to negate the effects of IR drop.

13. Public and/or environmental concerns in area of violation:
Not considering voltage drops could mask areas were cathodic protection is not adequate to protect the pipeline from corrosion. Corrosion could lead to a leak and along this pipeline potentially affect agricultural production or contaminate the Yellowstone River, the Clarks Fork of the Yellowstone or Rock Creek which could lead to fish kills, loss of public drinking water and loss or irrigation water.

14a. Person Interviewed: Procedure **Title:** _____
14b. Comments of person interviewed:

Violation No. 3

11a. CFR § Violated: §195.571

11b. Summarize what the regulation requires that operator did not do:
This regulation requires that cathodic protection (CP) monitoring criteria must meet the requirements of NACE Standard RP0169-96 paragraphs 6.2 and 6.3. RP0169-96 says that voltage drops must be considered when using the criteria of a negative potential of 850 mV with cathodic protection applied.

12. Provide detailed information about violation:
ExxonMobil uses the pipe to soil potential criteria of more negative than -850 mV with the CP applied and with respect to a copper/copper sulfate reference electrode. ExxonMobil however does not consider the voltage drops that are caused by the CP system's current or the currents generated from other sources.

NACE Standard RP0169-96 paragraph 6.2 requires that voltage drops be considered when taking these potential measurements. RP0169-96 paragraph 6.3 gives additional guidance in the applying those methods of voltage drop considerations.

FYI: When a CP monitoring reading is taken the potential (voltage) between the reference cell and the pipe determines if there is adequate protection against corrosion. Voltage drops are caused from current (I) passing through the earth (R) adjacent to the pipeline. Voltage(V)=Current(I) X Resistance (R). While a CP rectifier is operating there is current passing from the anode(the ground bed) to the cathode(the pipe). The volt meter cannot discern the difference between potential voltage and IR voltage. If current is not interrupted the meter reads the combination of IR voltage and potential voltage thus possibly making the reading appear larger than the potential reading alone. Therefore it is important that there be a method to negate the effects of IR drop.

One method of considering voltage drops is to take an "instant off" reading. This is accomplished by momentarily interrupting the CP system's current and concurrently taking a pipe to soil potential. NOTE: One must be careful to insure that all sources of current are being interrupted at the same time.

13. Public and/or environmental concerns in area of violation: If there is a corrosion leak it could be a public or environmental issue depending on the location.

14a. Person Interviewed: Van Cambron **Title:** Corrosion Tech.
14b. Comments of person interviewed: IR drop not considered.

15. Supporting Documents/Materials

Item No.	Description (Include date)	Source of Documents	Remarks
1.	ExxonMobil Procedures Manual May 25, 2001.	ExxonMobil	
2.	ExxonMobil September 11, 2002 letter to Texas Railroad Commission transmitting Procedures Manual for review	ExxonMobil	In this letter Exxon Mobil state the manual goes into effect 10/2002.
3.	NACE Standard RP0169-96 paragraphs 6.2 and 6.3	TSI	
4.	Fax transmitting ExxonMobil's Facilities Inspection and Maintenance Management System, Cathodic protection Program (CP procedures at the time of the 2002 Montana Facilities inspection.) (1/27/03)	ExxonMobil	States that this was the procedure at the time of the 2002 Montana facilities inspection.
5.	ExxonMobil's Facilities Inspection and Maintenance Management System, Cathodic protection Program (CP procedures at the time of this inspection.) (10/18/01)	ExxonMobil	See last page Section 7. No voltage drops are considered
6.	ExxonMobil's 2002 CP monitoring report (9/02)	ExxonMobil	No voltage drops were considered
7.	Close interval survey for a portion of the pipeline (Unknown)	ExxonMobil	Note that high readings in this segment are from other current influences, IR, which masks the true pipe to soil potential.

16. **Inspector's Signature:** _____ **Date:** 1/30/03

17. Compliance History

Date	Place	Describe Violation/ Noncompliance	CPF No. Date WL	Outcome
See Attachment	See Attachment	See Attachment	See Attachment	See Attachment

18. Gravity of Offense

Serious, not considering voltage drops can mask cathodic protection inadequacies, leading an operator to believe that the cathodic protection system is protecting the pipeline from corrosion when it is not.

19. Degree of Culpability

ExxonMobil is a large company and as such should have known what the new corrosion regulations required.

20. Ability to Continue in Business

Excellent

21. Ability to Pay

Excellent

22. Good Faith in Attempting to Achieve Compliance

Good

23a. Proposed Remedy

✓	Warning Letter
	Civil Penalty: Recommended Amount $ _____
✓	Compliance Order
	Hazardous Facility Order
✓	Notice of Amendment of O&M Plan

23b. Analysis of Proposed Remedy

24. Region Chief's Signature: _____ Date: 1/32/05

ExxonMobil Pipeline Company
800 Bell Street
Post Office Box 2220
Houston, Texas 77252-2220

Tommy G. Jackson
Pipeline Safety Advisor
Operations Integrity Department

ExxonMobil
Pipeline

May 25, 2001

Re: May 2001 Review of EPC's (Now EMPCo's) Liquids Procedural Manual for Operations, Maintenance, and Emergencies and Mobil Pipeline's Liquids Manual. File: 080-05.20 DOT 195, Operation and Maintenance

Mr. B.E. Ference:

We have reviewed former EPC's (Now EMPCo's) Procedural Manual for Liquid Pipelines, and MPL's Liquids Manual. This review is required by DOT regulations on an annual basis. There are no significant changes to the procedures that are currently included in these manuals.

The Manuals were subjected to a DOT Manuals Review during the week of May 15th, 2001, and revisions were made to clarify inspection schedules for breakout tanks. The procedures for complying with the new IMP regulations will be incorporated into the manual later this year.

As a matter of information, the EPC and MPL DOT Procedural Manuals will be combined by the end of 1st qtr 2002. The new Procedures Manual will contain procedures suitable for use on all liquid pipeline systems operated by EMPCo and it's affiliates. Until the combination of the manuals is completed, currently established and approved procedures should continue to be followed as referenced in the respective Procedural Manuals.

Tommy G. Jackson

KRB/TGJ/MHA

c Manual Holders

ExxonMobil Pipeline Compa
800 Bell Street
Post Office Box 2220
Houston, Texas 77252-2220

Kare ailor
Manager
Operations Integrity Department

ExxonMobil
Pipeline

Prior review May 2001

September 11, 2002

Mary L. McDaniel, P.E.
Assistant Director, Pipeline Safety
Gas Services Division
Railroad Commission of Texas
1701 North Congress Avenue
Post Office Box 12967
Austin, Texas 78711-2967

Re: ExxonMobil Pipeline Company
DOT Liquids Procedural Manual

Dear Ms. McDaniel:

Please find enclosed a copy of the new ExxonMobil Pipeline Company DOT Liquids Procedural Manual that will become effective October, 2002. This manual is being sent to you for review per 16 TAC 7.84 (d).

Should you have any questions, please contact Mr. Mike Adams (713-656-3926).

Sincerely,

BT Maguire for KR Bailor

Karen R. Bailor

KRB/MHA
Enclosure

Facsimile

ExxonMobil Pipeline

Date: January 27,2003
To: Mr. Gerald Davis
Title: P.E.
Company or Agency: DOT, Office of Pipeline Safety
Phone: 406-896-6003
Facsimile: 208-498-9058
From: David B. Sterling
Phone: 713-656-2258
Facsimile: 713-656-8232
Pager: 1-800-329-9488
E-Mail: david.b.sterling@exxonmobil.com

Subject: FIMMS Document (CP)
Pages: 9(Including cover page)
☒ URGENT!
☐ Please Comment / Reply
☐ FYI / Please Recycle

Copy To:

Message: Mr. Davis, please find attached the Cathodic Protection Program FIMMS document that we talked about. It is the document in force at the time of the Pipeline Safety Evaluation you performed on our Montana facility October 8 - 10th. If any portion of this does not come through, or if you have any further questions, please contact myself or Mr. Mike Adams, at the numbers I gave you during our phone conversation earlier today. Thank you.

ExxonMobil Pipeline Company
800 Bell Street, Room 623F
Houston, Texas 77002

An ExxonMobil Subsidiary

FACILITIES INSPECTION and MAINTENANCE MANAGEMENT SYSTEM	DATE: 10/18/01
ExxonMobil Pipeline Company	REVISION: 1.21
CATHODIC PROTECTION PROGRAM	PAGE: 1 of 8

I. SCOPE AND OBJECTIVE	This documentation describes the minimum requirements for ExxonMobil Pipeline Company's (EMPCO) Cathodic Protection Program covering inspections and associated documentation. It is intended to provide a framework to ensure compliance with applicable regulations. The Cathodic Protection Program is to provide adequate measures to protect its pipeline facilities from damage due to external corrosion.
II. RESOURCES	Program Steward: Corrosion Protection and Coatings Specialist Field Steward: Engineering Tech (ET) / Corrosion Tech (CT) Databases: CPDM, EMA, others local to work area
III. PROCESSES AND PROCEDURES	**A. PLANNING** EMPCO's P&P and government regulations set survey requirements and frequency. All scheduled inspections should be scheduled through EMA (or other local system where EMA is not available) to create work orders for Field implementation. Work described in this system includes: • Baseline survey of Protected Systems • Annual Cathodic Protection Surveys • Bi-monthly Rectifier and Bond Inspections
	B. EXECUTION **1. Baseline Survey of Protected Systems** A baseline survey should be conducted on each pipeline system within one year of its construction or acquisition. The system should then be energized to determine if it satisfies applicable criteria and operates efficiently. Permanent documentation of the survey results should be retained in the local Area files and copies sent to the Central Information Center (CIC) if required by Management. This survey may include the following types of measurements: • Native structure-to-soil potential (should be performed prior to anode installation for sacrificial system) • Structure-to-soil potential (energized)

	• Structure-to-soil intermittent (instant-off) potential (impressed currently only • Anode current output (output may be read individually or in-total depending on system design) • Continuity of structures if protected as a single structure • Structure-to-structure isolation if protected separately • Effect on adjacent structures (stray current effects) • Rectifier DC volts, DC amps, efficiency, and tap settings • Interference testing between this and other cathodically-protected structures
	2. Annual Cathodic Protection Surveys Annual cathodic protection inspections are required on all regulated facilities to ensure the effectiveness of cathodic protection. (The electrical measurements used in the inspection may include one or more of the measurements listed above.) Annual cathodic protection surveys are scheduled through EMA (or other local system where EMA is not available). Work orders are generated which call for the completion of the scheduled survey. Completed survey data is to be entered into the Cathodic Protection Data Manager (CPDM) database. All survey test points are to be tested and documented. Any test point which was not tested is to be brought to the attention of the Area Supervisor for explanation. Attempts should be made to repair or replace any missing test points which are critical to obtaining a representative survey of the system. If an unread test point is not critical (i.e. a representative survey is obtained without that reading), it may, with the approval of the Area Supervisor, be omitted from the survey. NOTE: Sound corrosion engineering practices should be observed when determining if a test point can be eliminated from a survey. Its omission shall not jeopardize the integrity of the survey or cause the survey to be less than representative of the condition of the system. Upon completion of the survey and review by the Area Supervisor (or his/her designee), the work order is terminated through EMA (or other local system where EMA is not available).

A hard copy of the CPDM survey data output is filed in local Area files and copies sent to the Central Information Center (CIC) if required by Management.

Key inspection actions include the following:

- Perform structure-to-soil (pipe-to-soil) potential measurements survey annually at intervals not exceeding 15 months.
- Inspect all bolted current-carrying connections for cleanliness and proper tightness. This includes rectifier bond connections.
- Inspect all ventilating screens in air cooled rectifier units for unobstructed air flow.
- Check oil level and cleanliness of oil immersed rectifier units.
- Inspect all electrical protective devices normally associated with rectifier operation (fuses, circuit breakers, and lightning arrestors) to be sure they are undamaged and in satisfactory operating condition.
- Check rectifier units for excessive dust accumulations and remove any insect nests or debris. Plug any holes through which insects or rodents could enter the rectifier.
- Test for interference current from outside sources.
- Check for evidence of corrosion on the protected system and, if coated, the condition of the coating.
- Check for exposure of groundbed cable and, if uncovered, inspect for insulation damage before re-covering.
- Check the effectiveness of dielectric insulating fittings, continuity bonds, and casing insulators

3. Rectifier and Bond Inspections

Inspection and tests of cathodic protection facilities should be made to ensure proper operation and maintenance. Key inspection points include the following:

- Inspect all sources of impressed current (rectifiers) six times per year at intervals not exceeding two and one-half (2 1/2) months. Evidence of proper functioning may be current output, normal power consumption, or satisfactory electrical state of the protected system. These inspections are scheduled through EMA (or other local system where EMA is not available).

	• Inspect proper functioning of all reverse current switches, diodes, and interference bonds, whose failure would jeopardize structure protection at intervals not exceeding 2 1/2 months.
	C. DATA MANAGEMENT All records associated with cathodic protection surveys, periodic rectifier readings, permanent test station data, and corrective actions taken are maintained in the computer database program, Cathodic Protection Data Manager (CPDM). Each Area ET / CT maintains the CPDM data for his/her respective area. Scheduling of the surveys is done through EMA (or other local system where EMA is not available). Printed copies of annual pipe-to-soil potential surveys are maintained in local Area files and copies sent to the Central Information Center (CIC), if required by Management, under the respective accounting location of each line segment or station.
	D. CORRECTIVE ACTION Actions taken to return a cathodic protection system to the required performance level will be site specific. It is recognized that the appropriate action will vary by situation and location. The ET / CT will decide the best course, based on his/her expertise and consultation as needed with supervisors, headquarters personnel, and reference materials. Inadequately protected facilities will be investigated, appropriate action taken to mitigate corrosion, and actions and results documented. For locations protected by impressed current systems: • Adjust existing rectifiers, if appropriate, to provide adequate current • Design and install additional ground beds to provide additional current, if needed • Recommend coating reconditioning, if needed • Recommend pipe replacement, if warranted For locations protected by galvanic anodes: • Determine if existing anodes have depleted or are still active

	• Determine if soil conditions (too dry) are preventing existing anodes from performing as needed (dry soil conditions increase soil resistivity, thus reducing the driving potential of the anode resulting in low pipe-to-soil potential.) • If existing anodes have depleted or if additional ones are needed due to an increase in current demand, install anodes as needed.
IV. VERIFICATION AND MEASUREMENT	**A. PROCESS** The Field Steward will ensure that all surveys are performed and documented as scheduled. (ET / CT, if other than the Field Steward, will keep the Field Steward informed of the status of his/her scheduled surveys.) The Program Steward may develop standardized tables for quarterly reporting by the Field Stewards as to the progress and status of work performed. Such reporting may include, but is not limited to: • Percentage of annual surveys due versus complete (by quarter). It is possible that such a percentage may be zero (due) for a quarter if none is scheduled, or all surveys could be 100% complete by the end of the first or second quarter of the year, if all are scheduled during that time. Status of bi-monthly rectifier surveys complete (i.e. All rectifiers and foreign bonds were checked as scheduled)
	B. RESULTS An annual summary report should be compiled by each Area to identify unprotected sections of pipe and action plans intended to remedy major deficiencies in cathodic protection program. In addition, the Program Steward will gather the number of leaks due to inadequate cathodic protection. The annual C/P summary report should be utilized in preparing the expected budget needs for the upcoming year, as well as a planning tool for manpower needs where substantial repair project are required.

VI REFERENCE MATERIALS	Effectiveness will be assessed by OIMS assessments as part of OIMS System 6-E and by periodic outside governmental agency audits. Corrosion standards and practices will be reviewed periodically and updated as needed. Updating of EMA (or other local system where EMA is not available) records affected by changes to CPDM information should occur as soon as such changes are known in order to avoid missing a scheduled survey.
	A. OVERVIEW There are very few plant and/or operating systems where zero corrosion of facilities may be expected. In fact, most equipment is designated with some corrosion allowance. It is part of the inspector's job to monitor and report on equipment corrosion so that it does not become a problem. Problems develop when corrosion goes undetected or is not properly addressed through good maintenance practices. The inspector should be aware of the various forms of corrosion and their possible causes so that he may detect and monitor them before they become a problem. When corrosion threatens to become a problem, the inspector is typically the first line investigator. Corrosion can often be detected by visual examination of equipment. However, some corrosion mechanisms cannot be detected unless other examination methods are used (including both destructive and nondestructive). This section will discuss various forms of corrosion and some examples commonly found on pipelines and associated facilities. Inspection and testing of cathodic protection systems during operation is an integral aspect of the preventative maintenance program. Failure to maintain effective system operation ultimately leads to inadequate protection from the cathodic protection system and subsequent corrosion of the protected system. Annual pipe-to-soil potential surveys as well as scheduled and unscheduled visual inspections of the facilities afford opportunities to discover areas in need of corrective measures.

Pipeline coatings are considered the first line of defense against external corrosion. Due to deterioration and imperfections in coatings cathodic protection is applied to supplement the efforts to mitigate corrosion. The practices contained in this section should be considered to ensure the integrity and reliability of the facility. The types of cathodic protection systems to which these practices apply include the following:

- Sacrificial anode systems
- Impressed current systems

B. TYPES OF CATHODIC PROTECTION SYSTEMS

1. Sacrificial Anode Systems

Sacrificial anode systems are comprised of galvanic anodes of such materials as magnesium, zinc, or aluminum. These are typically installed in the soil or water either bare or packaged in a special backfill material. The anodes are connected to the structure requiring protection with an insulated conductor, either singularly or in groups called groundbeds.

2. Impressed Current Systems

Impressed current systems use anode materials such as platinized titanium, silicon iron, graphite, lead-silver alloy, and scrap steel. These anodes are installed in the soil or water either bare or in special backfill material. They are connected with an insulated conductor either singularly or in groundbeds to the positive terminal of a direct current source, such as a rectifier or other DC power sources. The protected system is connected to the negative terminal of the direct current source.

Electrical measurements and inspections are necessary to determine that protection has been established according to applicable criteria and that each part of the cathodic protection system is operating properly. Conditions which affect protection are subject to change with time. Corresponding changes are required in the cathodic protection system to maintain protection

C. ACCEPTED CATHODIC PROTECTION CRITERIA

Due to electrochemical reaction between a metallic structure and its environment, the natural tendency of a metal alloy is to revert back to its natural state. In the case of a steel structure, that reaction is to return to the state of iron ore by the reduction process commonly known as "rust". The proper application of cathodic protection is a proven method of stopping the reduction process. Criteria for knowing when a sufficient current level has been reached and maintained have been accepted by the industry. Accepted cathodic protection criteria include:

- -0.850 volt pipe-to-soil potential with rectifier on (referenced to a common copper - copper sulfate electrode)
- 100 millivolt potential polarization decay
- Both of the above-mentioned criteria are accepted as providing evidence that cathodic protection has been achieved. Both are more fully explained in *NACE - Control of Pipeline Corrosion, 2001, by A. W Peabody* and other reference material.

D. REFERENCE DOCUMENTS

The following may be referred to concerning the Corrosion Control Program:

- EMPCO Policies and Procedures Manual
- NACE - Control of Pipeline Corrosion, 2001, by A. W. Peabody
- NACE RP-01-69- Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- ASM - Corrosion - Metals Handbook, Volume 13, Ninth Edition
- D.O.T. 192 and D.O.T. 195

Supporting Document 6

D.O.T.

25-301 LAUREL TO BILLINGS

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CU/SO4
SOIL COND.:	MOIST
DATE:	Sept. 2002

MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	RECTIFIER	REMARKS
0.000	0+00	EXXON REF.-V-1052	-1.082				
0.000	0+00	SKID-D/S FLANGE	-1.266				
0.000	0+00	SKID-UP/S FLANGE	-1.325				
0.000	0+00	TRAP	-1.335				
0.002	0+10	TK. 2,17	-1.880				
0+002	0+10	TK 4,5,6	-1.860				
0.015	0+82	V-1031	-1.166				
0.512	27+02	W.CHEM-R.R. XING-EAST	-2.000	-0.368	CLEAR		
0.524	27+68	W.CHEM-R.R. XING-WEST	-2.040	-0.350	CLEAR		
0.544	28+74	W.CHEM-R.R. XING-WEST	-2.050	-0.390	CLEAR		
		RECT. C-946				18V - 18A	
0.668	35+27	W OF RECT 946	-2.640				
0.852	45+00	R.R. SPUR XING-EAST	-1.800	-0.580	CLEAR		
0.865	45+00	R.R. SPUR XING-WEST	-1.800	-0.550	CLEAR		
1.102	58+19	FENCELINE	-1.586				
1.529	80+73	V-5602	-1.481				
1.693	89+43	YELLOWSTONE RIVER-EAST	-1.770				
1.859	98+15	YELLOWSTONE RIVER-WEST	-1.786				
1.974	104+20	MOV-5605	-1.532				
1.990	105+05	HWY 87 XING-EAST	-1.742	-0.570	CLEAR		
2.022	106+75	HWY 87 XING-WEST	-1.718	-0.540	CLEAR		
2.070	109+29	RR CROSSING WEST SIDE	-1.692	-0.648	CLEAR		
2.170	114+58	YALE TANK FARM	-1.661				ANODE 0 ma
2.316	122+30	YALE TANK FARM-EAST	-1.682				
		RECT. C-949				17V - 25A	
3.440	181+97	V-22	-1.410				
3.450	182+46	V-1053	-1.548				
4.770	219+07	DITCH	-1.650				
4.350	229+68	WEST SIDE OF SUGAR AVE	-1.485				
4.980	263+31	RIVERSIDE AVE.	-1.528				
5.300	280+10	WASHINGTON AVE	-1.333				
5.660	298+76	60' NORTH OF PI ON KING AVE EAST	-1.160				
7.690	406+51	CITY CNTR.-EAST	-1.216	-0.628	Jell Filled 10/27/97		
7.729	408+70	CITY CNTR.-WEST	-1.166	-0.564			
7.760	409+73	RR CROSSING S OF RYNS	-1.060	-0.428	CLEAR		
7.822	412+99	OB XING	-1.265				Anode 70ma Non Critical
7.860	415+01	R.R. SPUR XING-EAST	-1.080	-0.330			
7.973	420+96	R.R. SPUR XING-WEST	-1.108	-0.353			
8.051	425+08	KING AVE-WEST SIDE	-1.106	-0.668			
8.058	425+47	KING AVE	-1.145				
8.848	467+20	24TH ST. WEST	-1.540				
9.105	480+76	R.R. SPUR XING-EAST	-1.123				
9.132	482+16	R.R. SPUR XING-WEST	-1.117				
9.594	506+54	ROSCOE STEEL	-1.070				
10.054	530+84	AP 10	-1.054				
10.414	549+88	EAST END SHILOH REROUTE	-1.174				
10.513	555+10	WEST END SHILOH REROUTE	-1.160				
11.131	587+74	E. CANYON CRK. XING	-1.337				
11.331	598+29	SHILOH RD.-EAST SIDE	-1.422	-0.680	CLEAR		
11.350	599+29	CENEX RECT-WEST SIDE	-1.160	-0.640	CLEAR		
11.410	602+19	EAST END ELK RIVER CONCRETE	-1.310				
11.660	615+65	WEST END ELK RIVER CONCRETE	-1.135				
13.670	721+93	BLK. VALVE 7766	-1.196				
14.000	739+20	AERIAL MILE POST 14	-1.210				
14.940	788+82	N. SIDE OF R.R.	-1.248				
16.094	849+78	AP 16	-1.604				
16.139	852+14	RR X-ING, VENT, N. SIDE OF RR, W OFAP	-1.318	-1.263	Jell Filled 12/4/99		
16.186	854.610	RR XING SOUTH SIDE, CENEX TL	-1.270	-1.050			
16.263	858+67	TL NEAR CANYON CRK. DITCH	-1.520				
16.744	884+06	MDU XING	-1.281				5.1 amps WBI to XOM
16.812	887+68	E. side of Old HWY10 XING	-1.124	-0.683	Jell Filled 12/4/99		
17.185	907+36	MDU XING	-1.402				

25-301 LAUREL TO BILLINGS

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CU/SO4
SOIL COND.:	MOIST
DATE:	SEPT. 2002

MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	RECTIFIER	REMARKS
17.280	912+36	TL NEAR CANAL	-1.479				
17.371	917+24	CENEX CROSSING	-1.431				NEW TEST LEAD INSTALLED 3/19/02
17.392	918+32	R.R. YARD-EAST END	-1.350				
17.969	948+78	R.R. YARD-MIDDLE	-1.360				
17.994	950+06	EXXON/CONOCO/WB	-1.447				NEW INSTALLED 3/2/02
18.347	968+71	R.R. YARD-OVERPASS	-1.370				
18.373	970+09	STRAUCH/SHANNON RD	-1.203				Anode Bank 140 ma
18.778	991+46	R.R. YARD-FUEL DEPOT	-1.670				
18.820	993+70	CENEX XING	-1.857		CLEAR		
19.580	1033+84	OLD RECT SITE	-1.944	-0.350	CLEAR		
19.715	1040+95	N. SIDE I-90	-2.010	-1.505	CLEAR		Tested for short 8/2/96 - passed
19.912	1051+35	I-90 EXIT RAMP-S. SIDE	-1.857	-1.457	CLEAR		Tested for Short 8/2/96 - passed
20.002	1056+11	HWY 212/310 XING-EAST	-1.650	-0.570	CLEAR		
20.030	1057+61	HWY 212/310 XING-WEST	-1.870	-0.599	CLEAR		
20.033	1057+74	V-1056	-1.735				
20.125	1062+60	1st CENEX 24" CROSSING	-1.896	-0.630			Cenex Test Sta. PL #10; Casing #2
20.135	1063+13	2nd CENEX 24" CROSSING	-1.960	-0.658			Cenex Test Sta. PL #10; Casing #5

25-300 SILVERTIP TO LAUREL

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CU/SO4
SOIL COND.:	MOIST
DATE:	SEPT. 2002

MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	RECTIFIER	REMARKS
20.242	1068+77	FU V-1	-1.185	-0.732	CLEAR		E Case -1.074 Tested for short 8/96 - passed
20.243	1068+85	MOV-1067	-1.427				
20.365	1075+26	CENEX XING	-1.710				
		RECT. C-990				32A - 28V	
20.682	1092+02	V-4461	-2.540				
20.690	1092+44	40' E. OF V-4461	-1.998				
20.958	1106+56	RIVERSIDE PARK	-2.420				
21.023	1110+00	MOV-4462	-1.858				
21.461	1133+14	V-1057	-1.530	-0.460	CLEAR		
22.134	1168+65	AP 22	-2.080				
23.077	1218+45	WB XING	-1.925				
23.094	1219+35	WHITEHORSE BENCH RD.	-1.877				
24.380	1287+25	AP 24	-1.785				
24.997	1319+88	DAIRY FARM	-1.715				
25.953	1370+34	AP 26, V-1058	-1.410				
27.146	1433+31	DIRT RD.	-1.364				
28.099	1483+66	DITCH AT AP 28	-1.345				
29.305	1547+20	PRIVATE RD., CHILCOTT RD.	-1.490				
29.692	1567+72	HWY 310 XING-W. SIDE	-1.580	-1.010	CLEAR		
29.774	1571+00	OLD RR XING, W-SIDE	-1.520	-0.707	CLEAR		
29.776	1572+19	OLD R.R. XING-E-SIDE	-1.460	-0.680	CLEAR		
30.562	1613+65	NUTTING RANCH	-1.183				
30.576	1614+40	DITCH BEHIND TL	-1.180				
31.086	1641+35	V 4447	-1.370				
31.095	1641+81	N. SIDE RD. FROM V-4447	-1.210				
31.313	1653+33	S. SIDE OF ROCK CRK, JIM SPITZER'S	-1.120				NEW 4-27-2000
31.622	1669+62	S. SIDE RD. FROM MOV4448	-1.220				
32.125	1696+20	AP 32	-1.370				
33.152	1750+43	SILVER LEAF FARM	-1.870				
**33.96	1793+11	Williams Farm	-1.691				
34.171	1804+21	HWY 310 XING-E. SIDE	-1.608	-1.042	CLEAR		Tested for short 8/2/96 - passed
34.210	1806+23	HWY 310 XING-W. SIDE	-1.684	-1.088	CLEAR		
35.256	1861+52	RD.XING, WEST PRYOR RD.	-1.808				
36.394	1921+61	ELBOW CRK.	-1.898				
36.776	1941+78	E. SIDE OF RD. FROM V-1059	-2.390				
		Rect. C-1126				13V - 13A	
37.207	1964+55	THORMALEN LANE	-1.973				
38.491	2032+32	MOUNTAQUA RD.	-1.509				
39.129	2066+10	YEDLICKA FARM	-1.468				
39.811	2102+00	STEWARD PROP.	-1.892				
40.084	2116+43	AP 40	-1.907				
40.852	2156+99	FROMBERG WATER TK.	-1.205				
41.880	2211+26	AP 42	-1.651				
43.131	2277+31	V-1060	-1.206				
43.877	2316+73	S. SIDE RD. AT AP 44	-1.399				
44.660	2358+40	SAND CRK. RD.	-1.344				NEW 8-4-2000
44.855	2368+33	SAND CRK.	-1.340				
45.907	2423+88	AP 46	-1.340				
46.903	2476+48	BRIDGER BOOSTER ML	-1.592				
47.550	2510+64	COUNTY RD-W BRIDGER	-1.180				
48.308	2550+64	CEMETARY RD.-BRIDGER	-1.140				
49.299	2603+00	CURRY FARM	-1.240				
49.868	2633+03	MDU XING	-1.330				
49.973	2638+55	AP 50 AT V-1061	-1.213				
50.515	2667+20	HWY 72 XING W-SIDE	-1.110	-0.730	CLEAR		
51.439	2715+95	GOETZ FARM	-1.248				
52.526	2773+38	KELSEY FARM	-1.590				

25-300 SILVERTIP TO LAUREL

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CU/SO4
SOIL COND.:	MOIST
DATE:	SEPT. 2002

MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	RECTIFIER	REMARKS
53.327	2815+65	COUNTY RD., GOLDEN LANE	-1.614				NEW TEST WIRE 8-7-2000
54.351	2869+74	V-4449	-1.640				
		CLKS-Rect. C-1129				45V - 28A	
54.426	2873+70	MOV-4450	-1.240				
54.800	2895+56	N. SILVERTIP RD.	-1.198				NEW 8-7-2000
55.842	2948+45	AP 56, GRIFFIN LANE	-1.468				
56.844	3001+36	TL IN FENCE, HERDEN RANCH	-1.370				
57.090	3014+36	HERDEN RANCH	-1.202				NEW 8-7-2000
57.510	3036+50	HERDEN RANCH	-1.166				NEW 8-7-2000
57.843	3054+12	V-1063	-1.032				
58.040	3064+74	SOUTH OF AP 58	-1.230				NEW 8-8-2000
59.044	3117+53	MPC XING	-1.215				
59.590	3146+56	NEW STA. S. OF MP XING	-1.148				NEW 8-9-2000
59.843	3159+72	TL S. OF WASH	-0.952				
61.033	3222+55	TL IN SAGE BRUSH	-1.171				
61.515	3248+00	CATTLE TRAP, MPC XING	-1.028				
61.931	3269+93	N. OF AP 62	-1.207				
62.702	3310+67	MDU XING	-1.140				
63.098	3331+55	MPC XING	-1.203				
**63.14	3333+85	WB XING	-1.180				
**63.353	3345+02	9' W. of EB road	-1.150				
**63.559	3355+90	22' W. of EB road	-1.170				
**63.644	3360+39	MPC XING	-1.150				
63.956	3376+90	S. OF AP 64	-1.201				
64.756	3419+13	TL N. OF MDU XING	-1.260				
64.510	3406+18	MP XING	-1.221	1.478			
64.806	3421+75	MDU BOND	-1.240				
64.820	3422+51	MDU XING	-1.220				
65.013	3433+62	N. OF AP 66	-1.112				NEW 8-9-2000
65.511	3455+99	TL N. OF AP 66	-1.318				
66.554	3514+03	TL S. OF AP 66	-1.254				
66.770	3525+43	N. OF STOCK PENS	-1.330				NEW 8-9-2000
67.212	3548+79	COLO. GAS XING	-1.294				
67.495	3563+71	NEAR MDU RECT.	-1.563				
67.525	3565+30	TL E. of MDU Rect	-1.410				
68.057	3593+40	TL E. OF AP 68	-1.398				
68.700	3627+38	AMOCO PL XING	-1.690				
68.724	3628+66	V-1064	-1.702				
68.724	3628+66	Rect. C-945				13.5V - 60A	

SILVERTIP TANKS

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CU/SO4
SOIL COND.:	MOIST
DATE:	SEPT. 2002

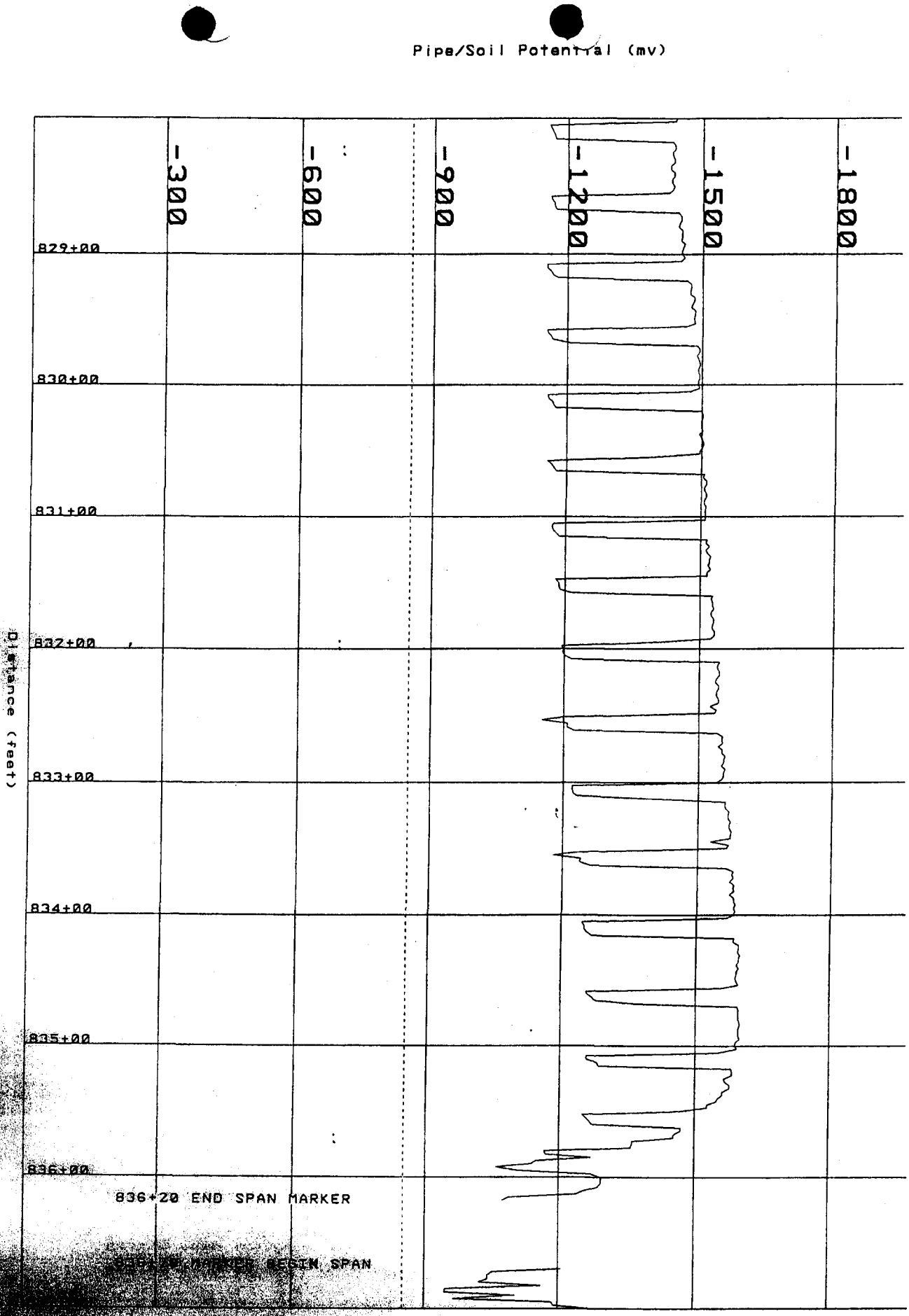
MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	FOREIGN P/S	REMARKS
SILVERTIP		TANK 252-NORTH	-0.943				
		EAST	-0.899				
		SOUTH	-0.903				
		WEST	-0.911				
		TANK 253-NORTH	-0.987				
		EAST	-0.988				
		SOUTH	-0.920				
		WEST	-1.102				
		TANK 254-NORTH	-1.110				
		EAST	-1.060				
		SOUTH	-1.126				
		WEST	-1.072				
		TANK 255-NORTH	-0.985				
		EAST	-0.987				
		SOUTH	-0.935				
		WEST	-1.015				
		TANK 319-NORTH	-2.090				
		EAST	-2.290				
		SOUTH	-2.222				
		WEST	-1.608				TS near water draw valve

STATION PSP READINGS

SURVEYOR:	D.C. Jackson
REF. ELEC.:	CU/CUSO4
SOIL COND.:	MOIST
DATE:	SEPT. 2002

MILE POST	STATION NUMBER	LOCATION	STRUCT P/S	CASING P/S	CASING STATUS	RECTIFIER	REMARKS
SILVERTIP							
		AMOCO BOND	-1.022				Bond to AMOCO 4.9ma
	TP #1	AMOCO FILL VALVE	-0.940				
	TP #2	MPL SAMPLE LOOP	-0.949				
	TP #3	D/S CHK. MTRS	-1.188				
	TP #4	V 40	-0.960				
	TP #5	V 32	-0.944				
	TP #6	UP/S UNIT #1	-1.173				
	TP #7	D/S UNIT #3	-1.129				
	TP #8	TRAP-BEHIND DOOR	-1.922				
	TP #9	6" BY-PASS ON TRAP	-1.651				
		RECTIFIER-STA. C-945				14.5V - 64.5A	
		RECTIFIER-TANKS C-956				42V - 10A	
LAUREL STA.	TP #1	DEL. MOV-E.SIDE,UP/S	-0.970				
	TP #2	DEL. MOV-W.SIDE,D/S	-1.600				
	TP #3	MTR. 74	-1.988				
	TP #4	MTR. 75	-1.968				
		RECTIFIER C-1146				11V - 7.5A	
		CENEX 310 XING FROM MOV 7767	-1.999	-0.690	CLEAR		
BILLINGS STA.	TP #1	SCRAPER TRAP	-1.675				
	TP #2	CONOCO MTR. 78, V-19	-1.280				
	TP #3	EXXON MTR. 81, V-9	-1.450				
		RECTIFIER C-949				17V - 25A	
BRIDGER BOOSTER		RECTIFIER C-1145				19V - 5.5A	
	TP #1	Strainer	-1.280				
	TP #2	D/S of Control Valve	-1.174				

Supporting Document 7


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
829+00
830+00
831+00
832+00
833+00
834+00
835+00
836+00
836+20 END SPAN MARKER
Distance (feet)

Pipe/Soil Potential (mv)

-300 -600 -900 -1200 -1500 -1800

838+00
839+00
840+00
841+00
842+00
843+00
844+00
845+00

Distance (feet)

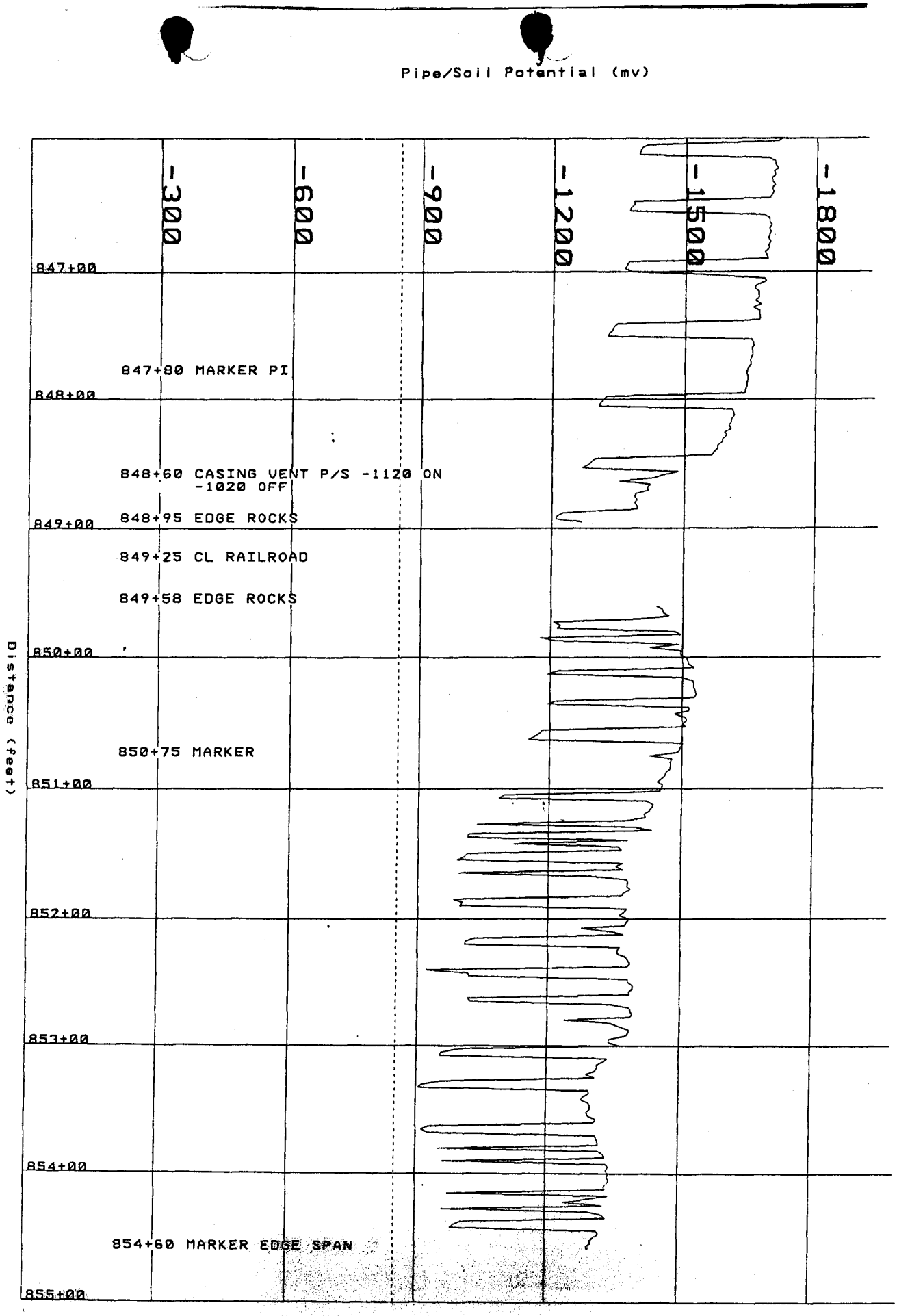
844+80 EXXON 12 INCH CRUDE
START AT TEST STATION
16.094 P/S -1566 ON
-1322 OFF

844+80 EXXON 12 INCH CRUDE
START AT TEST STATION
16.074 AIR MARKER 16 P/S
-1580 ON -1345 OFF

845+20 EDGE ASPHALT

845+80 EDGE ASPHALT ROAD MARKER

EXX-040 45
06*17*98 DAMP
12IN*040 URBAN


Pipe/Soil Potential (mv)
-300
-600
-900
-1200
-1500
-1800
Distance (feet)
847+00
847+80 MARKER PI
848+00
848+60 CASING VENT P/S -1120 ON
-1020 OFF
848+95 EDGE ROCKS
849+00
849+25 CL RAILROAD
849+58 EDGE ROCKS
850+00
850+75 MARKER
851+00
852+00
853+00
854+00
854+60 MARKER EDGE SPAN
855+00

CPF 5-2003-5006

09-29-03P12:37 RCVD

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Sent To Compliance Registry

Hearing 9/23/03

FACILITIES INSPECTION and MAINTENANCE MANAGEMENT SYSTEM	DATE: 03/05/03
ExxonMobil Pipeline Company	REVISION: 1.23
CATHODIC PROTECTION PROGRAM	PAGE: 1 of 12

I. SCOPE AND OBJECTIVE	This documentation describes the minimum requirements for ExxonMobil Pipeline Company's (EMPCo) Cathodic Protection Program covering inspections and associated documentation. It is intended to provide a framework to ensure compliance with applicable regulations. The Cathodic Protection Program objective is to provide adequate measures to protect its pipeline facilities from damage due to external corrosion.
II. RESOURCES	Program Steward: Corrosion Protection and Coatings Specialist Field Steward: Engineering Tech (ET)/Corrosion Tech (CT) Databases: CPDM, EMA, SAP PM or others local to work area
III. PROCESSES AND PROCEDURES	**A. PLANNING** EMPCO's P&P and government regulations set survey requirements and frequency. All scheduled inspections should be scheduled through EMA, SAP PM (or other local system where EMA, SAP PM are not available) to create work orders for Field implementation. Work described in this system includes: • Baseline survey of Protected Systems • Annual Cathodic Protection Surveys – DOT 195.573 (a)(1), DOT 192.465 (a) • Bi-monthly Rectifier and Bond Inspections – DOT 195.573 (c), DOT 192.465 (b) • Planning under EMPCO Integrity Management Program
	B. EXECUTION **1. Baseline Survey of Protected Systems** A baseline survey should be conducted on each pipeline system within one year of its construction or acquisition. The system should then be energized to determine if it satisfies applicable criteria and operates efficiently. Permanent documentation of the survey results should be retained in the local Area files and copies sent to the Central Information

Center (CIC) if required by Management. This survey may include the following types of measurements:

- Native structure-to-soil potential (should be performed prior to anode installation for sacrificial system)
- Structure-to-soil potential (energized)
- Structure-to-soil intermittent (instant-off) potential (impressed current only)
- Anode current output (output may be read individually or in-total depending on system design)
- Continuity of structures if protected as a single structure
- Structure-to-structure isolation if protected separately
- Effect on adjacent structures (stray current effects)
- Rectifier DC volts, DC amps, efficiency, and tap settings
- Structure to soil potential at all foreign crossings
- Interference testing between this and other cathodically-protected structures

2. **Annual Cathodic Protection Surveys**

Annual cathodic protection inspections are required on all regulated facilities to ensure the effectiveness of cathodic protection. (The electrical measurements used in the inspection may include one or more of the measurements listed above.)

Annual cathodic protection surveys are scheduled through SAP PM, EMA (or other local system where EMA, SAP PM are not available). Work orders are generated which call for the completion of the scheduled survey. Completed survey data is to be entered into the Cathodic Protection Data Manager (CPDM) database.

All survey test points are to be tested and documented. Any test point, which was not tested, is to be brought to the attention of the Area Supervisor for explanation. Attempts should be made to repair or replace any missing test points that are critical to obtaining a representative survey of the system. If an unread test point is not critical (i.e. a representative survey is obtained without that reading) it may, with the approval of the Area Supervisor, be omitted from the survey.

NOTE: Sound corrosion engineering practices should be observed when determining if a test point can be eliminated from a survey. Its

	omission shall not jeopardize the integrity of the survey or cause the survey to be less than representative of the condition of the system. Upon completion of the survey and review by the Area Supervisor (or his/her designee), the work order is terminated through EMA, SAP PM (or other local system where EMA, SAP PM are not available). A hard copy of the CPDM survey data output is filed in local Area files and copies sent to the Central Information Center (CIC) if required by Management. Key inspection actions include the following: **Pipe-to-soil Potentials** • Perform structure-to-soil (pipe-to-soil) potential measurement survey annually at intervals not exceeding 15 months. • Annual pipe-to-soil readings shall be taken at all test stations including pipe casing installations and foreign pipeline crossings per DOT 195.567, 195.577 & 16 TAC 7.86 (4). The annual pipe-to-soils shall be plotted and compared to the last three years. When a significant drop in potential is noted, further investigation should be scheduled to identify the cause. This may include but is not limited to, CIS of the affected area, interference testing with other metallic structures or foreign pipelines and site excavations to check condition of the pipeline and coating. • Test for interference current from outside sources. • Check for evidence of corrosion on the protected system and, if coated, the condition of the coating. • Check the effectiveness of dielectric insulating fittings, continuity bonds, and casing insulators. • Check for fault currents on pipelines that are in close proximity to electrical transmission tower footings, grounding cables, counterpoise or in other areas where it is reasonable to foresee damage from fault currents or where lightning may occur per 195.575 (e).
	Rectifiers and Bonds • Inspect all bolted current-carrying connections for cleanliness and proper tightness. This includes rectifier bond connections. • Inspect all ventilating screens in air-cooled rectifier units for unobstructed airflow.

	• Check oil level and cleanliness of oil immersed rectifier units. • Inspect all electrical protective devices normally associated with rectifier operation (fuses, circuit breakers, and lightning arrestors) to be sure they are undamaged and in satisfactory operating condition. • Check rectifier units for excessive dust accumulations and remove any insect nests or debris. Plug any holes through which insects or rodents could enter the rectifier. • Check for exposure of ground bed cable and, if uncovered, inspect for insulation damage before re-covering. • Inspect proper functioning of all company reverse current switches, diodes, and critical interference bonds (inter-company and foreign), whose failure would jeopardize structure protection as per EMPCo REGULATORY CORROSION INSPECTION SCHEDULE on page 12.
	3. STRAY CURRENTS – 195-577(a) When performing the annual pipe-to-soil survey CT/ET shall investigate for stray currents which may cause interference problems and take corrective action to mitigate the effects of stray currents using sound corrosion practices per NACE RPO169-2002 9.3 Detection of Interference Currents and 9.4, Methods for Mitigating Interference Corrosion Problems.
	4. ELECTRICAL ISOLATION OF FACILITIES DOT 195.575 ET/CT shall electrically isolate all company buried or submerged pipelines from other metallic structures, unless electrically interconnected and protected as a single unit. Electrical insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to prevent interference and facilitate the application of cathodic protection. All insulating devices must be inspected, tested (See EMPCo REGULATORY CORROSION INSPECTION SCHEDULE on page 12) to ensure the insulating devices are adequate and working properly, and maintained in accordance with the manufacturer's instructions. If an insulating device is installed in an area where a combustible

atmosphere is reasonable to foresee, precautions shall be taken to prevent arcing. No disconnection or reconnection shall be allowed when a flammable or explosive atmosphere is suspected without first testing to ensure a safe atmosphere.

Where pipelines are in close proximity to electrical transmission tower footings, ground cables, counterpoised, or in areas where it is reasonable to foresee fault currents or an unusual risk of lightning, action must be taken to prevent damage to the pipeline from fault currents or lightning. Information about protective measures at insulating devices may be found in NACE RPO177-2000 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems. These include but are not limited to:

Electrical Shields
Grounding Mats
Independent Structure Grounds
Bonding to Existing Structure
Distributed Anodes
Electrolytic Grounding Cells, Polarization Cells and Other Devices
Lightning Arresters

Note: In areas where pipelines are in close proximity to electrical transmission tower footings, ground cables, counterpoised, or in areas where it is reasonable to foresee fault currents or an unusual risk of lightning, safety precautions should be taken to prevent electrical shock of employees conducting the corrosion survey. *(Protective measures may be found in NACE RPO177-2000 Section 5 Personnel Protection.)*

AC potentials on structures must be reduced to and maintained at safe levels to prevent shock hazards to personnel. The degree of shock hazard and the threshold levels of current that can be tolerated by human beings depend on many factors. The degree of shock hazard depends on factors such as the voltage level and duration of human exposure, human body and skin conditions, and the path and magnitude of any current conducted by the human body. The magnitude of current conducted by the human body is a function of the internal impedance of the voltage source, the voltage impressed across the human body, and the electrical resistance of the body path. This resistance also depends on the contact resistance (i.e. wet or dry skin, standing on dry land or in water) and on the current path through the body (i.e., hand-to-foot, hand-to-hand). Personnel conducting corrosion surveys in these areas should use all safety precautions listed

	in NACE RPO177-2000 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems, Section 5 Personnel Protection.
	C. DATA MANAGEMENT All records associated with cathodic protection surveys, periodic rectifier readings, permanent test station data, and corrective actions taken are maintained in a computer database program such as Cathodic Protection Data Manager (CPDM). Each Area ET/CT maintains the data for his/her respective area. Scheduling of the surveys is done through SAP PM, EMA (or other local system where SAP PM, EMA are not available). Printed copies of annual pipe-to-soil potential surveys are maintained in local Area files and copies sent to the Central Information Center (CIC), if required by Management, under the respective accounting location of each line segment or station.
	D. CORRECTIVE ACTION Actions taken to return a cathodic protection system to the required performance level will be site specific. It is recognized that the appropriate action will vary by situation and location. The ET/CT will decide the best course, based on his/her expertise and consultation as needed with supervisors, headquarter personnel, and reference materials. For each pipeline that did not meet the criteria of the cathodic protection program a corrective action plan shall be developed and implemented as soon as possible, not to exceed 12 months (TRRC within 6 months for interference problems). All investigation, test results, and actions taken to mitigate corrosion will be documented by CT/ET. **For locations protected by impressed current systems:** • Investigate to ensure all rectifiers and ground beds are functioning properly. • Adjust existing rectifiers, if appropriate, to provide adequate

	current. • Design and install additional ground beds to provide additional current, if needed. • Recommend coating reconditioning, if needed. All coating materials must comply with the requirements of DOT 195.559. • Recommend pipe replacement, if warranted. **For locations protected by galvanic anodes:** • Determine if existing anodes have depleted or are still active. • Determine if soil conditions (too dry) are preventing existing anodes from performing as needed (dry soil conditions increase soil resistivity, thus reducing the driving potential of the anode resulting in low pipe-to-soil potential.) If existing anodes have depleted or if additional ones are needed due to an increase in current demand, install anodes as needed.
IV. VERIFICATION AND MEASUREMENT	**A. PROCESS** Supervisors responsible for cathodic protection must maintain a thorough knowledge of that portion of the corrosion control procedures established under DOT 195.402 (c) (3) for which they are responsible for ensuring compliance per DOT 195.555. The Field Steward will ensure that all surveys are performed and documented as scheduled. ET/CT, if other than the Field Steward, will keep the Field Steward informed of the status of his/her scheduled surveys. The Program Steward may develop standardized tables for quarterly reporting by the Field Stewards as to the progress and status of work performed. Such reporting may include, but is not limited to: Percentage of annual surveys due versus complete (by quarter). It is possible that such a percentage may be zero (due) for a quarter if none is scheduled, or all surveys could be 100% complete by the end of the first or second quarter of the year if all are scheduled

	during that time. Status of bi-monthly rectifier surveys complete (i.e. All rectifiers and foreign bonds were checked as scheduled).
	B. RESULTS An annual summary report should be compiled by each Area to identify unprotected sections of pipe and action plans intended to remedy major deficiencies in cathodic protection program. In addition, the Program Steward will gather the number of leaks due to inadequate cathodic protection. The annual C/P summary report should be utilized in preparing the expected budget needs for the upcoming year, as well as an OIMS (Operations Integrity Management System) planning tool for manpower needs where substantial repair projects are required.
V. FEEDBACK AND CONTINUOUS IMPROVEMENT	Effectiveness will be assessed by OIMS assessments as part of OIMS System 6-E and by periodic outside governmental agency audits. Corrosion standards and practices will be reviewed periodically and updated as needed. Updating of SAP PM, EMA (or other local system where SAP PM, EMA are not available) records affected by changes to CPDM information should occur as soon as such changes are known in order to avoid missing a scheduled survey.
VI. REFERENCE MATERIALS	**A. OVERVIEW** There are very few plant and/or operating systems where zero corrosion of facilities may be expected. In fact, most equipment is designed with some corrosion allowance. It is part of the inspector's job to monitor and report on equipment corrosion so that it does not become a problem. Problems develop when corrosion goes undetected or is not properly addressed through good maintenance practices. The inspector should be aware of the various forms of corrosion and their

possible causes so that he may detect and monitor them before they become a problem. When corrosion threatens to become a problem, the inspector is typically the first line investigator. Corrosion can often be detected by visual examination of equipment. However, some corrosion mechanisms cannot be detected unless other examination methods are used (including both destructive and nondestructive). This section will discuss various forms of corrosion and some examples commonly found on pipelines and associated facilities.

Inspection and testing of cathodic protection systems during operation is an integral aspect of the preventative maintenance program. Failure to maintain effective system operation ultimately leads to inadequate protection from the cathodic protection system and subsequent corrosion of the protected system. Annual pipe-to-soil potential surveys as well as scheduled and unscheduled visual inspections of the facilities afford opportunities to discover areas in need of corrective measures.

Pipeline coatings are considered the first line of defense against external corrosion. Due to deterioration and imperfections in coatings, cathodic protection is applied to supplement the efforts to mitigate corrosion. All external pipe coatings required by DOT Subpart H 195.557 must be electrically inspected during construction just prior to lowering the pipe into the ditch or submerging the pipe. All coating damage discovered must be repaired per DOT Subpart H 195.561 (b). When any buried pipe is exposed for any reason, it shall be examined for external corrosion and documented on PL-751C or RCF 1011.

The practices contained in this section should be considered to ensure the integrity and reliability of the facility. The types of cathodic protection systems to which these practices apply include the following:

- Sacrificial anode systems
- Impressed current systems

B. TYPES OF CATHODIC PROTECTION SYSTEMS

1. Sacrificial Anode Systems

Sacrificial anode systems are comprised of galvanic anodes of such materials as magnesium, zinc, or aluminum. These are typically installed in the soil or water either bare or packaged in a special backfill material. The anodes are connected to the structure requiring protection with an

insulated conductor, either singularly or in groups called ground beds.

2. Impressed Current Systems

Impressed current systems use anode materials such as platinized titanium, silicon iron, graphite, lead-silver alloy, and scrap steel. These anodes are installed in the soil or water either bare or in special backfill material. They are connected with an insulated conductor either singularly or in ground beds to the positive terminal of a direct current source, such as a rectifier or other DC power sources. The protected system is connected to the negative terminal of the direct current source.

Electrical measurements and inspections are necessary to determine that protection has been established according to applicable criteria and that each part of the cathodic protection system is operating properly. Conditions, which affect protection, are subject to change with time. Corresponding changes are required in the cathodic protection system to maintain protection.

C. ACCEPTED CATHODIC PROTECTION CRITERIA

Due to electrochemical reaction between a metallic structure and its environment, the natural tendency of a metal alloy is to revert back to its natural state. In the case of a steel structure, that reaction is to return to the state of iron ore by the reduction process commonly known as "rust". The proper application of cathodic protection is a proven method of stopping the reduction process. Criteria for knowing when a sufficient current level has been reached and maintained have been accepted by the industry. Accepted cathodic protection criteria include:

- A negative (cathodic) potential of at least 850 mv with the cathodic protection applied. Potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops must be considered using sound engineering practices. Acceptable methods for considering voltage drops may include (but are not limited to) instant off potentials, and cathodic protection analyzers. Other methods not listed may be utilized, but must comply with NACE Standard RPO169-96. A record of each inspection, survey and test to demonstrate the adequacy of the cathodic protection must be maintained.
- 100 millivolt potential polarization decay
- Both of the above-mentioned criteria are accepted as providing evidence that cathodic protection has been achieved. Both are

	more fully explained in *NACE - Control of Pipeline Corrosion, 2001, by A. W Peabody* and other reference material. The use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbonding of the coating per NACE RPO 169-2002 Section 6.2.2.3.3. High pipe to soil potential on well-coated pipelines may be experienced when they are in close proximity of cathodic protection ground beds. Whenever high potentials are found further investigation should be done because high potentials on well-coated lines can cause coating degradation and disbonding. On bare or poorly coated pipelines this may not be a problem but consideration should be given to ensure pipelines in high current gradient areas do not cause interference with other foreign structures.
	D. REFERENCE DOCUMENTS The following may be referred to concerning the Corrosion Control Program: • EMPCO Policies and Procedures Manual • NACE - Control of Pipeline Corrosion, 2001, by A. W. Peabody • NACE RPO169-2002 Control of External Corrosion on Underground or Submerged Metallic Piping Systems • NACE RPO 177-2000 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems • ASM - Corrosion – Metals Handbook, Volume 13, Ninth Edition D.O.T. 192 and D.O.T. 195

EMPCo REGULATORY CORROSION INSPECTION SCHEDULE

ITEM	DOT 192 & TRRC	DOT 195, CSFM & LDNR
Annual pipe-to-soils	Once each calendar year not to exceed 15 months	Once each calendar year not to exceed 15 months
Rectifiers or impressed current sources	Inspect six times a year not to exceed 2-1/2 months	Inspect six times a year not to exceed 2-1/2 months
Reverse current switch, diode, and interference bond (critical bonds) whose failure would jeopardize structure protection	Inspect six times a year not to exceed 2-1/2 months	Inspect six times a year not to exceed 2-1/2 months
All other cathodic protection bonds	Once each calendar year not to exceed 15 months	Once each calendar year not to exceed 15 months
Insulating and electrical isolating devices	Once each calendar year not to exceed 15 months	Once each calendar year not to exceed 15 months

CSFM California State Fire Marshal
DOT 192 & 195 Department of Transportation
LDNR Louisiana Department of Natural Resources
TRRC Texas Railroad Commission & TAC (Texas Administrative Code)

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Karen R. Ballor
Manager
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2003 MAR 21 PM 4:22 - due to office closure, may have been delivered upon previous three days

ExxonMobil Pipeline

March 17, 2003

Mr. Chris Hoidal, P.E.
Director, Western Region
Office of Pipeline Safety
12600 West Colfax Avenue, Suite A-250
Lakewood, Colorado 80215

3 Copies / Date 4.10.03
Sent To Compliance Registry

Re: Notice of Probable Violation, Proposed Compliance Order, and
Notice of Amendment CPF No. 5-2003-5006

Dear Mr. Hoidal:

This letter outlines ExxonMobil Pipeline Company's (EMPCo's) response to your letter, CPF No. 5-2003-5006, received February 18, 2003, regarding the pipeline safety inspection of EMPCo's Silver Tip to Billings system, performed by Mr. Gerald Davis on October 8-10 and November 21, 2002.

Mr. Davis noted three alleged probable violations to which EMPCo offers the following response.

Silver Tip to Billings Crude Oil Line **CPF No. 5-2003-5006, Item No. 1**

Requirement: 49 CFR 195.402 - "Procedural manual for operations, maintenance, and emergencies. (a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to ensure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted."

Alleged probable violation to the above named system: Records indicate that ExxonMobil completed their 2001 Procedural Manual review on May 25, 2001. A letter to the Railroad Commission of Texas dated September 11, 2002 asserts that a new Procedural Manual was to become effective in October 2002. Between May 25, 2001 and October 2002 there was no review of the existing Procedural Manual which exceeds the requirement that a company review it's procedural manual once each calendar year not to exceed 15 months.

EMPCo's Response: We disagree that a probable violation to the cited regulation has occurred. In May of 2001, the Department of Transportation, Office of Pipeline Safety conducted the 5 year review of EMPCo's OM&E manuals. The audit team consisted of Mr. Bob Holter (Southwest Region), Mr. Chuck Behounek (New England Region), Mr. Peter Katchmar (Western Region), and Mr. Greg Hindman (Southern Region). EMPCo had just completed a process of combining Exxon Pipeline Company's DOT Procedural Manual and Mobil Pipe Line Company's DOT Liquids Manual, and presented this manual to the inspection team for their review. This manual did not meet their expectations and a decision was made to review the prior manuals utilized by Exxon Pipeline and Mobil Pipe Line. The inspection team allowed EMPCo the opportunity to take a different approach in preparing a new manual and informed EMPCo that the new manual would be subject to another audit in 2002. The inspection team granted EMPCo a grace period until the audit in 2002 to rework the manual, review all processes and procedures, etc. The manual was completed in September of 2002, and became effective October 1, 2002. In early 2002, Mr. Buddy Sheets, Department of Transportation, Office of Pipeline Safety, scheduled an audit for the week of November 4, 2002, to again review the new DOT Liquids Manual and other OM&E plans. There were no out of compliance findings during this audit and Mr. Sheets and his team were very pleased with the OM&E manuals and programs.

EMPCo fully understands its responsibility to annually review its procedural manuals and document accordingly. We have a process in place to accomplish this. Between May 25, 2001 and October of 2002, the DOT Liquids Manual was under constant review and revision to prepare for the audit that was scheduled for the week of November 4th. Because the revision to the manual was a wholesale change, over many months, no single date could be given as the revision date except the October 1, 2002 date, when the newly reworked manual became effective.

Silver Tip to Billings Crude Oil Line CPF No. 5-2003-5006, Item No. 2

Requirement: 49 CFR 195.402 - "Procedural manual for operations, maintenance, and emergencies. (c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations: (3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part."

Alleged probable violation to the above named system: ExxonMobil's CP monitoring procedures do not reference or use the monitoring criteria in NACE Standard RP0169-96 as required in 195.571. Specifically ExxonMobil's procedure does not have provisions for considering voltage drops. ExxonMobil must amend their procedures to include CP monitoring criteria as listed in NACE Standard RP0169-96 paragraphs 6.2 and 6.3.

EMPCo's Response: We disagree that a probable violation to the above cited regulation has occurred. EMPCo's procedures, in place at the time of the pipeline safety inspection, though not referencing specifically numerated paragraphs of NACE Standard RP0169-96, did reference the standard as a whole, along with four other reference documents. All of these are found in section D of the Facilities Inspection and Maintenance Management System (FIMMS) document which was in force at the time of the safety inspection. By referencing the entire NACE Standard, EMPCo includes CP monitoring criteria listed in the standard, in the same manner that the DOT OPS incorporates matter by reference.

Silver Tip to Billings Crude Oil Line **CPF No. 5-2003-5006, Item No. 3**

Requirement: 49 CFR 195.571 - "What criteria must I use to determine the adequacy of cathodic protection? Cathodic protection required by this subpart 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 Standard RP0169-96 (incorporated by reference, see Sec. 195.3)."

Alleged violation to the above named system: CP monitoring records show that voltage drops are not being considered, as required in NACE Standard RP0169-96 paragraphs 6.2 and 6.3 when annual cathodic pipe to soil potentials are being taken. ExxonMobil is using the criteria of -850mV with the impressed cathodic protection current on and uninterrupted. RP0169-96 only allows the use of a -850mV criteria after voltage drops have either been accounted for or deducted.

EMPCo's Response: The negative 850mV criteria is listed as one which does consider voltage drop, as described in Peabody's Control of Pipeline Corrosion, by A.W. Peabody (second edition) , page 51, second paragraph, where it is stated that "A potential of -850mV was adopted to provide a 50 mV margin of protection. The effectiveness of the criterion has been demonstrated over many years of application." This criteria was established because it was noted "that the most negative potential observed for coated underground steel structures was about -800mV." Since it is well known that the native potential of pipeline steel is typically between -300mV and -600mV, this provides a large voltage drop consideration. In pipeline environments a native potential that approaches -800mV would be very rare.

Consideration of voltage drop was, and is, built into the -850mV criteria as described in the Peabody book. EMPCo, by utilizing this criteria, and applying sound engineering practices as described in NACE Standard RP0169-96, does consider voltage drop as part of its corrosion control program, and this is now stated in the FIMMS documentation which replaces the version that was in place at the time of the October 2002 safety inspection. This is supported by historical leak records, exposed pipe inspection records, internal inspection records (line log data), previous annual and close interval survey records, and instant off readings taken during the October safety inspection itself. The criteria EMPCo uses to evaluate the effectiveness of its corrosion control program, as indicated in NACE Standard RP0169-96, are not limited to the -850mV instant off method only.

EMPCo personnel held a meeting with Mr. Richard Norsworthy (NACE International Corrosion Specialist #4037), who served for twelve years on the committee that formulated the RP0169-96 document. Mr. Norsworthy presently teaches classes for NACE. He vigorously stressed that the NACE documentation states "It is not intended that persons responsible for external corrosion control be limited to the criteria listed below. Criteria that have been successfully applied on existing piping systems can continue to be used on those piping systems. Any other criteria used must achieve corrosion control comparable to that attained with the criteria herein." EMPCo utilizes such criteria. Mr. Norsworthy indicated that it is inadvisable to utilize a -850mV instant off criteria only, for the purpose of demonstrating adequate cathodic protection, and offered the following reasons.

A. It is very difficult to accurately perform an instant off test, unless using very sophisticated equipment.
B. The -850mV instant off criteria cannot be used effectively on pipeline systems with Galvanic anodes that are attached below ground.
C. It is very difficult to properly interrupt all current sources because of unknown, buried bonds and other current sources.
D. Instant off is not easy to use on multiple pipeline right of ways.

E. To achieve this criteria, which is difficult to do on poorly coated structures, many companies raise their potential levels far beyond adequate protection levels. This can cause:

1. Interference problems with other metal structures.
2. Potential coating problems or damage.
3. Excessive use of power, equipment, and manpower.
4. Potential hydrogen embrittlement

Regarding the two concerns mentioned in CPF No. 5-2003-5006, it is EMPCo's intention to complete the inspections / repairs to the remaining breakout tanks within the next four years.

The HCA baseline for the Silver Tip to Billings line was to be established in 2006. Due to your concern EMPCo will review the data from the 2001 MFL tool run and work with our present HCA schedule, along with out tool vendors to determine the appropriate time frame within which to run the geometry tool in the Silver Tip to Billings line.

Because our (EMPCo's) position is that no violations have occurred, additional costs of procedure implementation will not be incurred.

We believe this addresses the alleged probable violations cited resulting from the October 8-10, 2002 pipeline safety inspection. If you have further questions or concerns, please contact Mr. David Sterling at (713) 656-2258

Sincerely,

Karen Bath

C2

ExxonMobil Pipeline Company
800 Bell Street
Post Office Box 2220
Houston, Texas 77252-2220

Karen R. Ballor
Manager
Operations Integrity Department

2003 MAY 23 PM 12:51

ExxonMobil
Pipeline

May 19, 2003

Mr. Chris Hoidal, P.E.
Director, Western Region
Office of Pipeline Safety
12600 West Colfax Avenue, Suite A-250
Lakewood, Colorado 80215

Re: CPF No. 5-2003-5006

Dear Mr. Hoidal,

After the Pipeline Safety Inspection of October 8-10 and November 21, 2002, performed on ExxonMobil Pipeline Company's (EMPCo's) Silver Tip to Billings system by Mr. Gerald Davis, EMPCo received a Notice of Probable Violation (NOPV), Proposed Compliance Order and Notice of Amendment (CPF No. 5-2003-5006) on February 19,2003. On March 17, 2003, EMPCo submitted written comments to your office addressing each of the three allegations described in CPF No. 5-2003-5006. In these written comments EMPCo contested the allegations contained in the Notice of Probable Violation, and provided information supporting EMPCo's position.

We hope this information sufficiently resolves the concerns expressed by the OPS. However, in the event that the information provided has not resolved this matter, then EMPCo does wish to schedule this matter for a hearing to discuss all allegations raised in the NOPV, at which time EMPCo will be accompanied by council.

Should you need additional information or have further questions, please contact Mr. David Sterling at (713) 656-2258.

Sincerely,

Karen Ballor

CH 10/17/03

ExxonMobil Pipeline Compan
800 Bell Street
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Karen Bailor
Manager
Operations Integrity Department

ExxonMobil
Pipeline

October 13, 2003

5-2003-5006

10-17-03A11:39 RCVD

Mr. Chris Hoidal, P.E.
Director, Western Region
Office of Pipeline Safety
12600 West Colfax Avenue, Suite A-250
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3 Copies / Date 10-28-03
Sent To Compliance Registry

Dear Mr. Hoidal:

Thank you for the opportunity to meet with you and your staff on September 23, 2003 in Denver to discuss matters related to ExxonMobil Pipeline Company's (EMPCo) Montana pipeline system.

As a follow-up to the meeting, we would like to take this opportunity to summarize what we understand to be the remaining issues with respect to the NOPV. First, considering Allegation #3, it is our impression that OPS no longer questions whether EMPCo considers voltage drops in its Cathodic Protection (CP) monitoring practices in accordance with NACE Standard RP0169. Rather, the issue is whether EMPCo adequately demonstrates such considerations procedurally.

Concerning Allegation #2, it is EMPCo's perception that OPS no longer disputes that EMPCo had the requisite references to the NACE criteria in the applicable manual. Nonetheless, OPS indicated that additional language in the manual could provide clarification with respect to the process. With respect to both Allegations #2 and #3, EMPCo has provided the OPS the most recent version of EMPCo's Facilities Inspection and Maintenance Management System Manual, which provides a more detailed account of the NACE criteria and EMPCo's CP procedures. Based on our discussions at the hearing, we are optimistic that this version of the manual will satisfy your remaining concerns with respect to Allegations #2 and #3.

Finally, with respect to the first issue raised in the NOPV, we hope that the information we provided demonstrated that our review of EMPCo's and MPLCO's manuals was within the regulatory timeframe. We also appreciated your clarification that the OPS did not consider this item to be a probable violation, but rather a warning.

It has been our experience that meetings between EMPCo and OPS, even in the context of an informal hearing, serve to improve communications between our offices. We look forward to continuing this trend. Please contact me if you would like any to see any additional documents concerning these matters.

Sincerely,

Karen R Bailor

Cc: Mr. Larry T. White
US Department of Transportation
Research and Special Programs Administration
Office of the Chief Counsel
400 Seventh St. S.W.
Washington, DC 20590

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

Office of the
Chief Counsel

400 Seventh St., S.W.
Washington, D.C. 20590

09-14-04 A10:34 RCVD

JUL - 1 2004

Andrew K. Turner
Vice President, Operations
ExxonMobil Pipeline Company
800 Bell Street
Houston, TX 77002

Re: CPF No. 5-2003-5006

Dear Mr. Turner:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It withdraws one of the allegations of violation and the associated compliance order and finds that you have addressed the inadequacies in your procedures that were cited. Therefore, you need not take any further action with respect to the matters in this case. This enforcement action is now closed. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: Ms. Karen Bailor
Manager, Operations Integrity Department

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
ExxonMobil Pipeline Company,	)	CPF No. 5-2003-5006
	)	
Respondent.	)	
	)	

FINAL ORDER

On October 8-10 and November 21, 2002, pursuant to 49 U.S.C. § 60117, a representative of the Office of Pipeline Safety (OPS) conducted an on-site pipeline safety inspection of ExxonMobil Pipeline Company's (Respondent's) facilities and records in Montana. As a result of the inspection, the Director, Western Region, OPS, issued to Respondent, by letter dated January 30, 2003 a Notice of Probable Violation, Proposed Compliance Order, and Notice of Amendment (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent committed violations of 49 C.F.R. Part 195 and proposed that Respondent take certain measures to correct the alleged violations. The Notice also alleged inadequacies in Respondent's operations, maintenance, and emergencies (OM&E) procedures and proposed in accordance with 49 C.F.R. § 190.237 that Respondent amend its procedures.

Respondent responded to the Notice by letter dated March 17, 2003 (Response). Respondent contested the allegations, offered information in explanation of the allegations, and requested a hearing. The hearing was held on September 21, 2003 in Denver, Colorado.

WITHDRAWAL OF ALLEGATION

Item 3 of the Notice alleged that Respondent violated 49 C.F.R. § 195.571 by failing to consider voltage drops in determining the adequacy of the cathodic protection on its lines. The corrosion control provisions of the pipeline safety regulations incorporate NACE Standard RP0169-96 and require operators using the 850 mV negative cathodic potential criterion to correct for voltage drop in order to arrive at valid interpretations of their pipe-to-soil measurements. The value of the voltage drop and the methods of correcting for it must be determined by selecting and applying sound engineering methods. The universally accepted method is to interrupt the flow of current at the rectifier and measure the magnitude of the voltage drop using the "instant off" technique. Once measured, the voltage drop may be used for correcting future pipe-to-soil measurements at the same location as well as other test points in the area provided conditions such as soil characteristics and coating quality remain constant. When the instant off method is impracticable or otherwise

determined inappropriate for a particular pipeline or pipeline section, the use of extrapolation methods to determine the polarized potential of pipe structures and computerized survey techniques are also acceptable methods of accounting for voltage drop.

In its response and at the hearing, Respondent demonstrated that its cathodic protection practices in effect accounted for voltage drops. Specifically, Respondent demonstrated that up-to-date close-interval electrical survey data for the entire pipeline and comprehensive information on the output levels of all impressed current rectifiers along with other corrosion control records were integrated with other relevant operational data and analyzed for the purpose of determining the adequacy of the cathodic protection on its pipelines. Based on an extrapolation analysis of this data, Respondent's corrosion specialist concluded that if all environmental factors remained constant and the annual pipe-to-soil measurements and rectifier outputs maintained their current levels, a determination that voltage drops had been accounted for was warranted with respect to the subject pipeline. Having considered this information demonstrating substantial compliance with the regulation, I am withdrawing this allegation of violation and the Proposed Compliance Order associated with it.

AMENDMENT OF PROCEDURES

Item 2 of the Notice alleged that Respondent's written OM&E procedures were inadequate in that they failed to describe Respondent's method for considering voltage drops in interpreting its annual pipe-to-soil measurements and failed to indicate how it was to be implemented by its personnel. Under § 195.402, operators must have written procedures implementing the OM&E requirements in Part 195. In its response, Respondent demonstrated that NACE Standard RP0169-96 was referenced in its OM&E manual. Respondent, however, failed to demonstrate that the manual being used by its field personnel at the time of the inspection described its process for considering voltage drops in a manner that would have permitted the OPS inspector to evaluate the capacity of this process to produce valid results or determine whether it had been fully implemented and followed by the responsible personnel. After the hearing, Respondent submitted documents demonstrating that it had amended its OM&E manual to direct the systematic use of an extrapolation method to assess and monitor the polarized potential of pipe structures. Specifically, Respondent's revised procedures require annual pipe-to-soil measurements to be plotted against the measurements for the preceding three years and require any significant deviations to be investigated and corrected. The Director, Western Region, OPS has reviewed the revised procedures and accepted them as adequate in light of the fact that Respondent's practice of performing comprehensive cathodic protection data collection and integration (see Item 3 discussion above) has demonstrated satisfactory results. Accordingly, I find that Respondent's original procedures as described in the Notice were inadequate to ensure the safe operation of its pipeline system, but that Respondent has corrected the identified inadequacies. Because Respondent's actions have satisfied the proposed amendment of procedures, it is unnecessary to issue an order directing amendment of Respondent's procedures.

WARNING ITEM

The Notice did not propose a civil penalty or corrective action for Item 1. Therefore, it is considered a warning item. Respondent presented information its response and at the hearing showing that it has addressed the cited item. Respondent is again warned that if OPS finds a violation for this item in a subsequent inspection, enforcement action will be taken.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a petition for reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The terms and conditions of this Final Order are effective on receipt.

for Stacey Gerard
Associate Administrator
for Pipeline Safety

JUL - 1 2004
Date Issued

ExxonMobil Pipeline Company
Post Office Box 2220
Houston, Texas 77252-2220

ExxonMobil
Pipeline

August 7, 2009

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Material Safety Administration
12300 W. Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: DOT Audit of ExxonMobil Pipeline's Montana Facilities

Dear Mr. Hoidal:

ExxonMobil Pipeline Company's (EMPCo) Montana pipeline facilities were inspected by Mr. Mike Petronis of your office during the week of July 27, 2009. In the close-out meeting, Mr. Petronis informed the attendees that he would discuss his findings with you prior to preparing the final audit findings letter. We trust that the discussion between the two of you will include the comments in this letter, which we have reviewed directly with Mr. Petronis.

As suggested by Mr. Petronis, EMPCo immediately began developing a plan to address the findings from the inspection and will have photographs to show the progress made within the next 30 days. While EMPCo agrees with the majority of the potential findings by Mr. Petronis, there are two of the items suggested by Mr. Petronis for possible inclusion in a Warning Letter with which EMPCo respectfully disagrees.

At the Clark's Fork river crossing, Mr. Petronis advocated enhancements to the existing signage on the river bank. EMPCo suggests that even if the location should require these signage enhancements, this finding is easily corrected and not worthy of being mentioned in a Warning Letter. In addition, while supplementary separation between the pipe and the pipe supports at the Silvertip Station may be advantageous, no corrosion was found during either the atmospheric corrosion inspection or the DOT inspection. EMPCo's assertion is that both of the above-mentioned items are more correctly made as "suggested best practices" versus as "possible violations".

In conclusion, our company is disappointed with the outcome of this inspection. EMPCo is never satisfied when we or a regulatory agency find any shortcomings in our processes. It is EMPCo's intent to maintain and operate our facilities to the highest standards, meeting or exceeding minimum regulatory requirements. We will continue to strive toward excellence and flawless operations of our pipeline facilities.

Thank you for your consideration of our comments. If you wish to discuss any of these issues further, please contact Larry Hawthorne at 903-654-5345.

Sincerely,

Brian T. Magruder

Attachments
c - J. E. James
c - J. B. Rose
c - J. J. Montgomery
c - C. D. Wile
c - S. E. Davenport
c - M. Petronis


WARNING
DO NOT ANCHOR
OR DREDGE
PETROLEUM PIPELINE CROSSING


RNING
ROLEUM
ELINE
TING OR IN EMERGENCY
1-800-537-5200
l Pipeline Company
USTON, TEXAS

To CV

-29-10P03145 2010

COPY

POST INSPECTION MEMORANDUM

Inspector: Michael Petronis
Reviewed: HJN 11/29/10
Follow-Up Enforcement: None
Director Approval* CH

Date: October 25, 2010

Operators Inspected:	**OPID:**	**Region:** Western
ExxonMobil Pipeline	4906	
Williston Basin Pipeline	22655	

Unit Addresses:
ExxonMobil Pipeline Company
110 Cemetery Road
Bridger, MT 59014

Williston Basin Pipeline
2010 Montana Avenue
Glendive, MT 59330

Units Inspected: Silvertip Pipeline System (ExxonMobil) **Unit ID:** 1255
Elk Basin to Billings System (Williston Basin) **Unit ID:** 2785

Unit Type: Interstate Hazardous Liquid (ExxonMobil)
Interstate Natural Gas (Williston Basin)
Inspection Type: I04 – Public Inquiry Investigation
Record Location: Bridger (ExxonMobil), Glendive (Williston Basin)
Inspection Dates: October 20, 2010
AFOD: 0.5
SMART Activity Number: 131606

Operator Contact: Jeb Montgomery, Area Superintendent (ExxonMobil)
Craig Wagner, Pipeline Integrity Manager (Williston Basin)

Unit Description:

✗
ExxonMobil's Silvertip Pipeline delivers crude oil from the Silvertip Station (Elk Basin) in extreme southern Montana east of Belfry to the ExxonMobil Refinery in Billings, MT. The pipeline is approximately 69 miles long, outside diameter is 8.625 in. and 12.75 in., wall thickness varies from 0.250 in. to 0.500 in, and the grade is X35 and X42.

Williston Basin's Elk Basin to Billings Pipeline delivers natural gas from Elk Basin in southern Montana to Billings. WBI has a valve setting on both sides of the Yellowstone River approximately 1,847 feet apart. A new 16 inch line was bored and installed in 2009. The bore consists of .375" wall thickness, grade X52, FBE coated pipe with an abrasion resistant overcoat. The other river crossing was installed in 1983 and is also a 16 inch diameter pipeline. Each end of the crossing has some .312" wall thickness, grade X52 pipe. The actual crossing is 1,143 feet long, 16 inch, 0.500 inch wall thickness, grade B that is FBE coated pipe that is also concrete coated. The majority of the Elk Basin to Billing system consists of looped 12 inch diameter pipe with some 10 inch and 8 inch diameter pipe installed as well.

Facilities Inspected:

ExxonMobil and Williston Basin pipeline crossings of the Yellowstone River and Riverside Park South of Laurel, MT.

Persons Interviewed:

Steve Everett, Technician Leader, ExxonMobil	406-670-7520
James Caniglia, City Planner, Laurel MT	406-628-4796
Kurt Markegard – Public Works Director, Laurel, MT	406-628-4796
Roger Perking, Engineer, Aquoneering, Billings	406-655-4660
Jeb Montgomery (on phone), Area Superintendent, ExxonMobil, Billings	406-657-5400
Jeff Harmon (on phone), Foreman, ConocoPhillips, Billings	406-860-1001
Craig Wagner (on phone), Pipeline Integrity Manager,Williston Basin	406-359-7216

Probable Violations/Concerns:

There may be a potential issue related to the depth of the ExxonMobil Silvertip Pipeline crossing and one of the Williston Basin Pipeline crossings of the Yellowstone River just south of Laurel, MT in the event of unusually high flows in the river. The river bank/dike is eroding on the north side of Riverside Park (south side of the Yellowstone River) that could impact the integrity of the pipelines if the pipelines were exposed by scouring of the river bottom and/or continued erosion of the river bank.

Continue to monitor closely. CH

Follow up on the history of prior offenses that are still open

There are not any prior offenses that are still open for these units.

Recommendations:

1. Work with ExxonMobil Pipeline, Williston Basin Interstate Pipeline and the City of Laurel to obtain accurate depth of cover surveys of the pipeline crossings of the Yellowstone River and Riverside Park. Use this data in conjunction with a geomorphology study of the river bank and Riverside Park being conducted for the city of Laurel to determine if the scouring/erosion potential could impact the pipelines. If the data indicates that the pipelines could be impacted, direct the pipeline operator(s) to make modifications to their pipelines to ensure that they would not be damaged in the event of continued river scouring and/or riverbank erosion.

2. Follow up with the Army Corps of Engineers and/or the Federal Emergency Management Agency regarding funding options that the city of Laurel could utilize to stabilize the riverbank from continued erosion.

Comments:

1. I Spoke with Jeff Harmon (406-860-1001), ConocoPhillips Pipeline Foreman in Billings prior to the meeting. He indicated that CPPL's pipeline across the Yellowstone River is idle and was purged with Nitrogen in the early 1990's.

2. Steve Everett indicated that he would speak to the engineering department at ExxonMobil about obtaining an updated depth of cover survey of the Silvertip Pipeline across the the river and Riverside Park. It was agreed that ExxonMobil would respond to me by October 29, 2010 to provide an estimated timeframe by which the depth of cover survey could be completed. (~ 6 - 8 weeks)

3. Kurt Markegard has spoken with numerous different agencies/organizations including Montana Fish Wildlife and Parks, US Army Corps of Engineers, Montana Department of Transportation, Burlington Northern Santa Fe Railroad, etc concerning the river bank erosion along the northern side of Riverside Park in an effort to obtain funding to stabilize the river bank to prevent further erosion. Kurt indicated he has not had much success in obtaining a funding source and his efforts have been complicated due to the number of various agencies/organization potentially involved with the project.

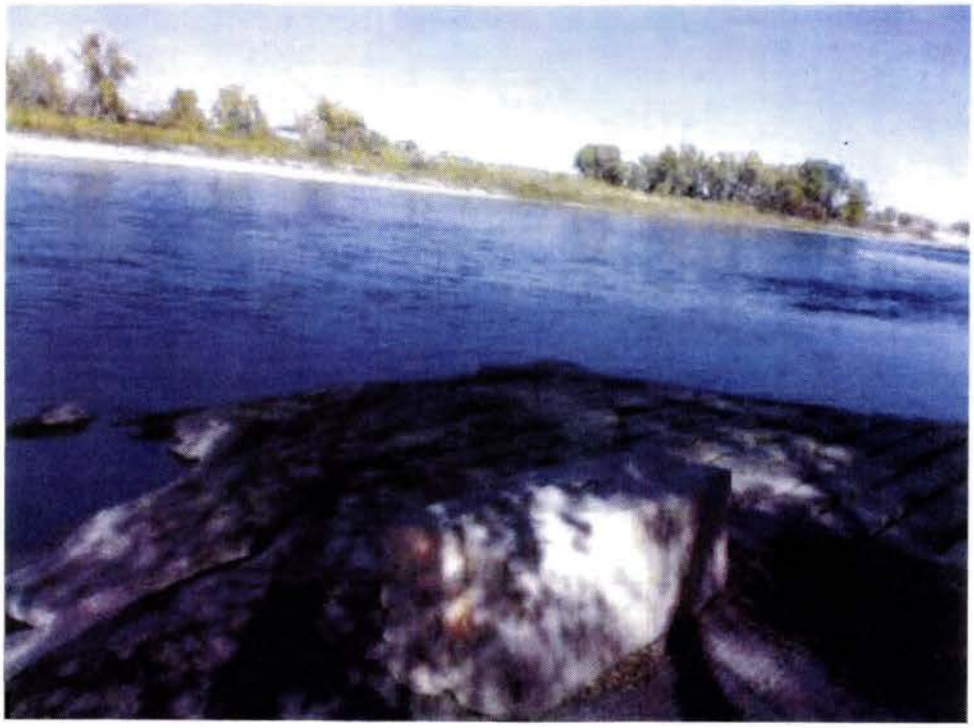
4. The City of Laurel has contracted with a local engineering firm (Aquoneering in Billings) to conduct a geomorphology study to determine the effects of continued erosion of the riverbank and the damage that would be caused in the event of high river flow conditions (ie. 100 year flood).

5. After the meeting on October 20, I spoke with Craig Wagner from Williston Basin Interstate Pipeline in Glendive, MT. Craig indicated that WBI has two (2) 16 inch pipelines crossing the Yellowstone River and Riverside Park south of Laurel. An 8 inch pipeline operated by WBI ruptured in June 2009 during high runoff conditions on the Yellowstone. WBI installed a new 16 inch bored crossing in the fall of 2009 (see attached

profile drawing). WBI has another16 inch pipeline that was installed via an open cut trench across the river that is much shallower (see attached profile drawing). Craig indicated that WBI has the ability to shut in the shallower pipeline in the event of failure and run all of the gas flow through the deeper pipeline.



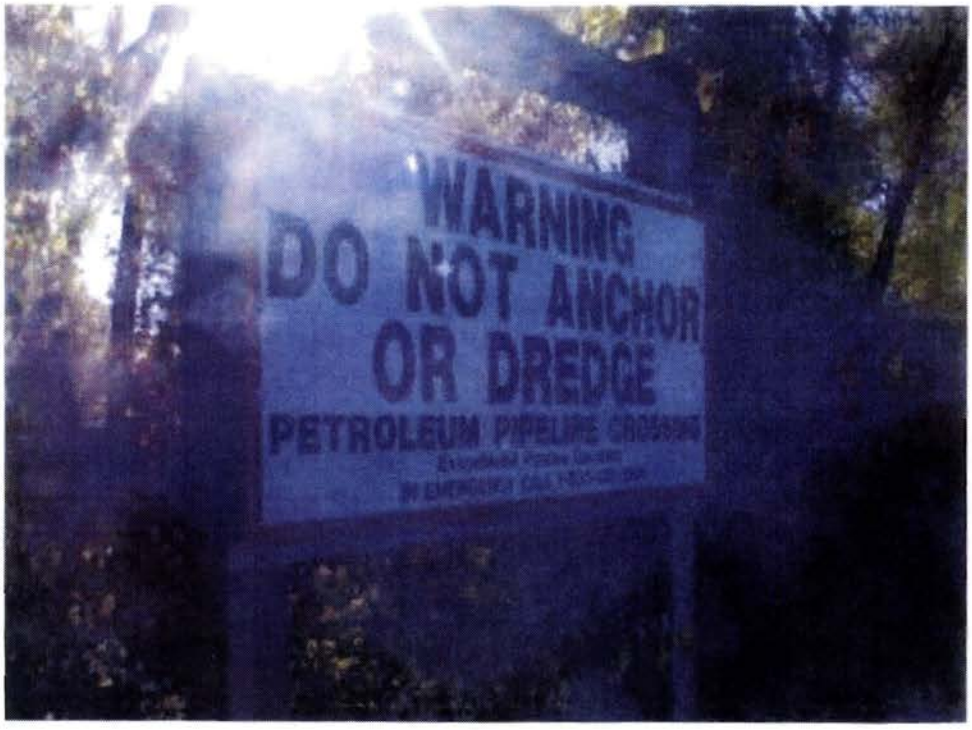
Damaged boat ramp – ExxonMobil Pipeline crosses the Yellowstone River aaproximately 50 feet downstream (to the right) from here. One of the WBI pipelines reported crosses directly under it.



Damaged boat ramp



Looking downstream of boat ramp – note ExxonMobil's pipeline warning sign on bank



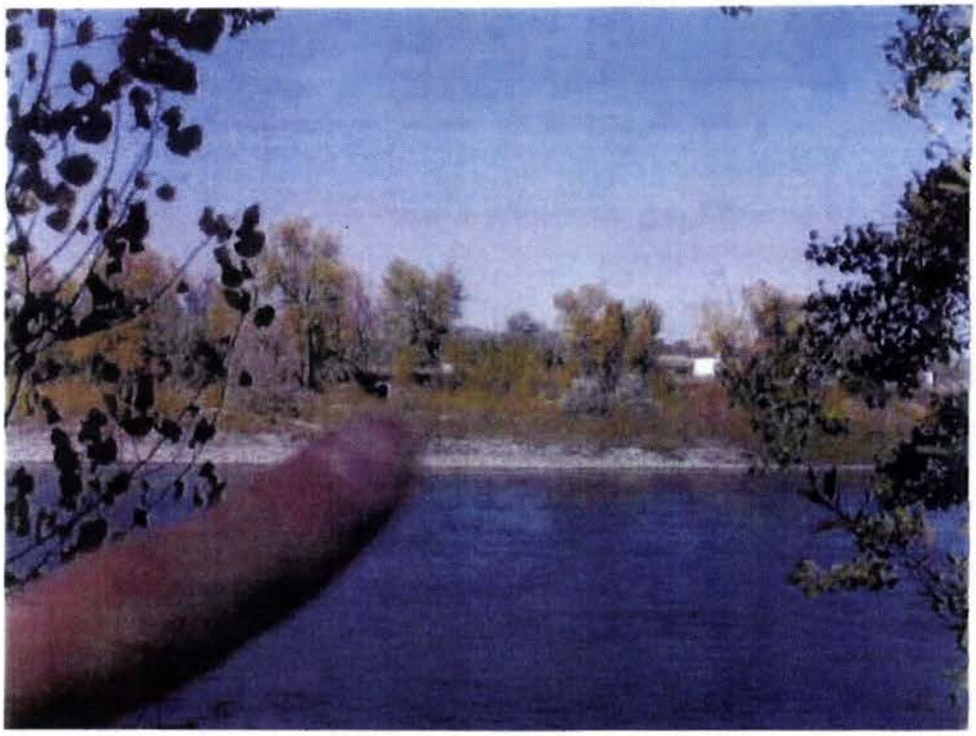
ExxonMobil's pipeline warning sign on south bank of river



Riverbank upstream of boat ramp (view is looking downstream)



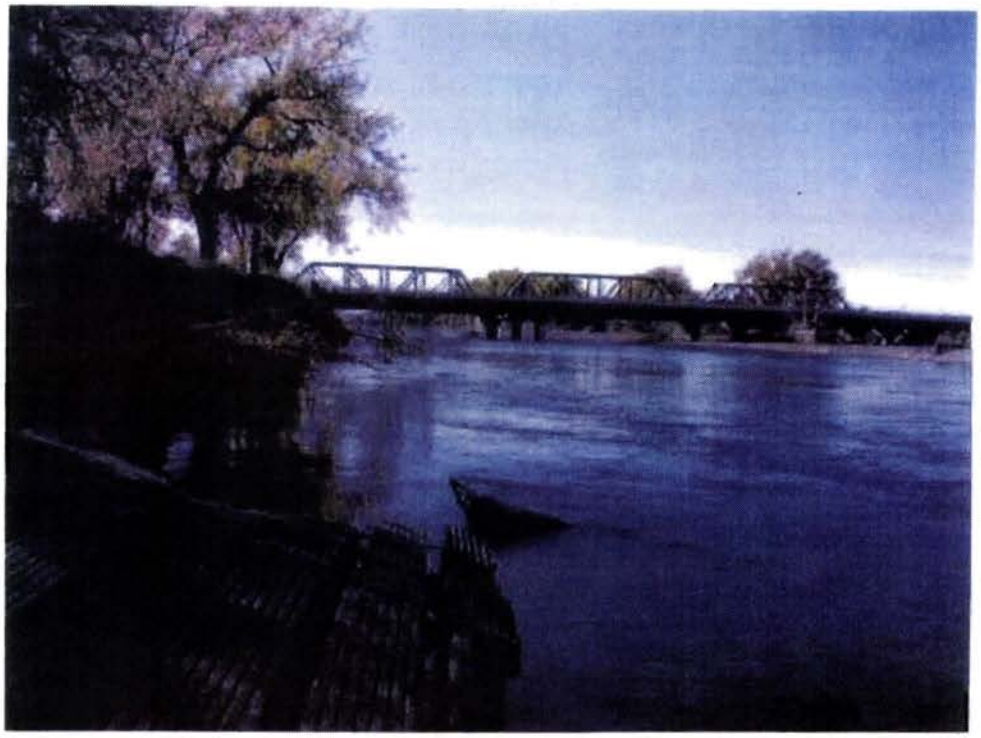
ExxonMobil pipeline marker – looking north across the Yellowstone River



Pointing at pipeline sign on the north side of the river



ExxonMobil pipeline marker - looking south into Riverside Park



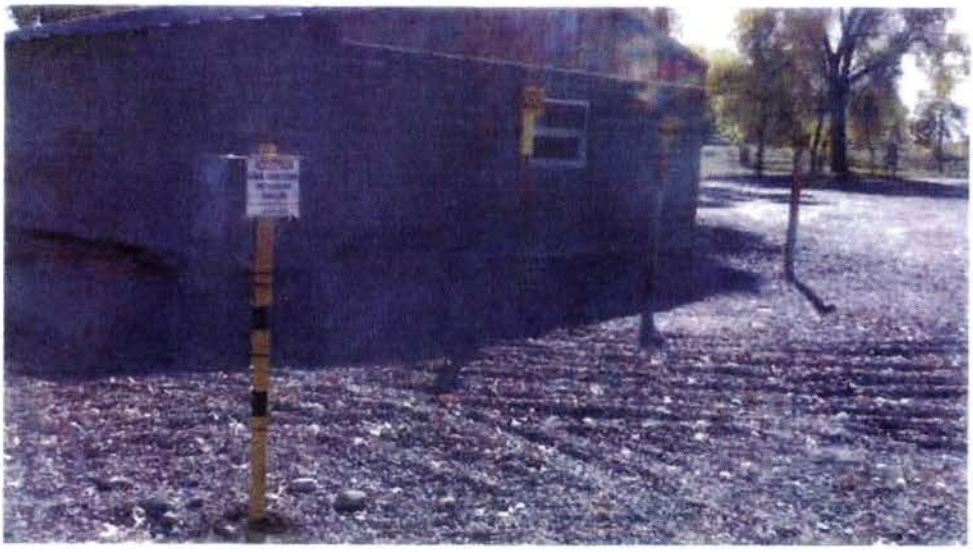
Looking west from the damaged boat ramp to the state highway bridge and railroad bridge



ExxonMobil's pipeline warning sign on the south bank of river



Williston Basin pipeline warning sign in Riverside Park – looking north towards river



ConocoPhillips and Williston Basin pipeline warning signs in Riverside Park



ExxonMobil Silvertip Pipeline Block Valve on southern edge of Riverside Park



Williston Basin pipeline marker – looking north