01-30-12A06:53 RCVD

POST INSPECTION MEMORANDUM

Inspector: Kuang Chu/UTC
Reviewed: Joe Subsits/UTC
Peer Reviewed: RR
Follow-Up Enforcement: No Violation
PCP* PCO* NOA WL LOC
Director Approval* CJL
4/22/12

Date: November 2, 2011

Operator Inspected: Exxon Mobil Oil Corporation **OPID:** 32009 **Region:** Western

RECEIVED
APR 27 2012
State of Washington
UTC
Pipeline Safety Program

Unit Address:
6311 East Sharp Ave.
Spokane Valley, WA 99212

Unit Inspected: Spokane Terminal **Unit ID:** 10635

Unit Type: Interstate Hazardous Liquid

Inspection Type: I01 – Standard Inspection, I07 – IMP Field Verification, & Follow up, I08 – OQ Field Verification

Record Location:
6311 East Sharp Ave.
Spokane Valley, WA 99212

Inspection Dates: 10/10, 11, 12 & 14/2011

AFOD: 4 (I01-3.0, I07-0.5, I08-0.5)

SMART Activity Number: # I01 / 133016 3 days # I07 / 137878 0.5 day I08 / #137879 0.5 day

emailed to J. Haddow

Operator Contact: Laura Sleevi
Phone: (509) 534-8132 **Fax:** (509) 534-8177 **Emergency:** 1-800-537-5200

Unit Description: The Spokane Terminal consists of six breakout tanks and associated piping. All the breakout tanks have been modified to double bottom and can re-inject products into the Yellowstone Pipeline. The terminal is primarily a truck loading facility. Ethanol and biofuel are transported to the terminal by rail tankers for blending.

Facilities Inspected: All 6 breakout tanks and associated piping at the Spokane Terminal were inspected during the field verification. The rectifier and all CP test points were inspected and pipe-to-soil potentials were taken.

Persons Interviewed:

Laura Sleevi	Area Supervisor
Dave Ort	West Coast Corrosion Control Coordinator
Larry Doc Hawthorne	Pipeline Safety Compliance Advisor
Dave Berard	Foreman
Emily Moeller	Field Engineer

Probable Violations/Concerns:
There were no probable violations or concerns.

Follow up on the history of prior offenses that are still open:

Prior Offenses (for the past 5 years)		
CPF #	**What type of open enforcement action(s)?**	**Status of the regulations(s) violated (Reoccurrence Offenses, Implement a NOA Revision, Completion of PCO or CO, and etc...)**

Recommendations:
Continue to inspect this unit every other year.

Comments:
None

Attachments:
- PHMSA Form 10 Breakout Tank Inspection Form
- PHMSA Form 13 PHMSA Drug & Alcohol Questions
- PHMSA Form 15 Operator Qualification Field Inspection Protocol Form
- PHMSA Form 19 Hazardous Liquid IMP Field Verification
- Field Data Collection Form
- Form W – 1162 Public Awareness Program Field Audit
- Western Region-Unit Information Form

Version Date: 5/5/08

BREAKOUT TANK INSPECTION FORM

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: Kuang Chu, 11/3/2011	**Inspector/Submit Date:**	Kuang Chu, 11/3/2011
	Peer Review/Date:	
	Director Approval/Date:	CH 4/22/12

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Exxon Mobil Oil Corporation	**OPID #:**	32009
Name of Unit(s):	Spokane Terminal	**Unit #(s):**	10635
Records Location:	**Spokane, WA**	**Activity #**	
Unit Type & Commodity:	Refined Products		
Inspection Type:	Standard Inspection	**Inspection Date(s):**	October 10, 11, 12 & 14, 2011
PHMSA Representative(s):	Kuang Chu/UTC	**AFO Days:**	4

Summary:
The Spokane Terminal consists of six breakout tanks and associated piping. All the breakout tanks have been modified to double bottom and can re-inject products into the Yellowstone Pipeline. The terminal is primarily a truck loading facility. Ethanol and biofuel are transported to the terminal by rail tankers for blending.

Findings:
The thermowell for tank T-505 has been removed following the incident on November 3, 2008. A procedure for removing thermowell for calibration was developed for existing threaded thermowells. A new design for flanged thermowells has been developed by the operator. All threaded thermowells will be replaced by flanged thermowells whenever the tanks are undergoing an out-of-service internal inspection in the future. The cathodic protection for buried piping has been improved and meets code requirements. All 6 breakout tanks were externally inspected while in-service by a certified API 653 Inspector in August 2010. There were no probable violations found during this inspection.

Company System Maps (copies for Region Files):	
Validate SMART Data (components, miles, etc): ☐	**Acquisition(s), Sale or New Construction**(submit SMART update): ☐
Validate Additional Requirements Resulting From Waiver(s) or Special Permit(s):	

BREAKOUT TANK INSPECTION FORM

Name of Operator:	ExxonMobil Oil Corporation		
OP ID No. [1]	32009	**Unit ID No.** [1]	10635
HQ Address:		**System/Unit Name & Address:** [1]	
ExxonMobil Oil Corporation 800 Bell St. Room 741-D Houston, TX 77002		6311 East Sharp Ave. Spokane Valley, WA 99212	
Co. Official:	Laura K. Sleevi, Area Supervisor	**Activity Record ID #:**	
Phone No.:	509-534-8132 Ext. 2	**Phone No.:**	509-534-8132, Ext. 2
Fax No.:	509-534-8177	**Fax No.:**	509-534-8177
Emergency Phone No.:	800-537-5200	**Emergency Phone No.:**	800-537-5200

Persons Interviewed	**Title**	**Phone No.**
Laura Sleevi	Area Supervisor	509-534-8132
Dave Ort	West Coast Corrosion Control Coordinator	661-763-7616
Larry Doc Hawthorne	Pipeline Safety Compliance Advisor	903-654-5345
Dave Berard	Foreman	509-534-8132
Emily Moeller	Field Engineer	310-212-3748

PHMSA Representative(s) [1]	Kuang Chu/UTC	**Inspection Date(s)** [1]	October 10, 11 12 & 14, 2011
Company System Maps (Copies for Region Files):			

Comments:

For hazardous liquid operators, the attached evaluation form should be supplemented with PHMSA Form 3 and 49 CFR 195 during PHMSA inspections.

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

BREAKOUT TANK INSPECTION FORM

		Design and New Construction of Aboveground Breakout Tanks	S	U	N/A	N/C
.132	(a)	Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.	X			
	(b)	After Oct. 2, 2000 compliance with paragraph (a) above requires:				
		(1) Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels and with internal vapor space pressures that are approximately atmospheric must be designed and constructed in accordance with **API Specification 12F, (11th edition, November 1, 1994, reaffirmed 2000, errata February 2007).**	X			
		(2) Welded, low-pressure (i.e., internal vapor space pressure not greater than 15 psig) carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with **API Standard 620, (11th edition, February 2008, addendum 1 March 2009).**	X			
		(3) Vertical, cylindrical, welded steel tanks with internal pressures at the tank top approximating atmospheric pressures (i.e., internal vapor space pressures not greater than 2.5 psig, or not greater than the pressure developed by the weight of the tank roof) must be designed and constructed in accordance with **API Standard 650, (11th edition, June 2007, addendum 1, November 2008).**	X			
		(4) High pressure steel tanks (i.e., internal gas or vapor space pressures greater than 15 psig) with a nominal capacity of 2000 gallons or more of LPG must be designed and constructed in accordance with **API Standard 2510, (8th edition, 2001).**	X			

Comments:

		Tank Repairs, Alterations, and Reconstruction Procedures	S	U	N/A	N/C
.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			
	(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,** or its predecessor **Standard 12C,** must be repaired, altered, or reconstructed according to **API Standard 653, (3rd edition, December 2001, addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)).**	X			
		(2) Tanks built to **API Specification 12F,** or **API Standard 620,** 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**, repaired, altered, or reconstructed will be in accordance with **API 510, (9th edition, June 2006).**	X			

Comments:

BREAKOUT TANK INSPECTION FORM

		Impoundment, Protection Against Entry, Relief, and Venting Procedures	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			
	(b)	(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, *Flammable and Combustible Liquids Code*, (2008 edition, approved August 15, 2007):**				
		(i) Impoundment around a breakout tank must be installed in accordance with Section 3.2.3.2; and	x			
		(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, (8th edition, 2001).**	x			
	(c)	Aboveground breakout tank areas must be adequately protected against unauthorized entry.	x			
	(d)	Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Each low-pressure and high-pressure breakout tank must have pressure/vacuum-relieving devices.	x			
	(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 and 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, (applicable edition IBR at time of installation).**	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,* (applicable edition IBR at time of installation).**	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 normal and emergency venting requirements in **API Standard 2000, (applicable editions IBR at time of installation).**	x			
		(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, (applicable edition IBR at time of installation).**	x			

Comments:

		Pressure Test Procedures/Pressure Testing Aboveground Breakout Tanks	S	U	N/A	N/C
.307	(a)	Aboveground breakout tanks built to **API Specification 12F** and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of **API Specification 12F (applicable edition IBR at time of testing).**	x			
	(b)	Aboveground breakout tanks built to **API Standard 620** 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 (applicable edition IBR at time of testing).**	x			
	(c)	Aboveground breakout tanks built to **API Standard 650** and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section **5.3.5 of API Standard 650 (applicable edition IBR at time of testing).**	x			

BREAKOUT TANK INSPECTION FORM

Pressure Test Procedures/Pressure Testing Aboveground Breakout Tanks			S	U	N/A	N/C
	(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** 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, (applicable editions IBR at time of testing).**	x			
	(e)	Aboveground breakout tanks **built to API Standard 2510** and first placed in service after October 2, 2000, pressure testing must be in accordance with **ASME Boiler and Pressure Vessel Code, Section VIII, Div.1 or 2, (applicable edition IBR at time of testing).**	x			
.310	(a)	A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.	x			
	(b)	The record required by paragraph (a) of this section must include: (1) The pressure recording charts; (2) Test instrument calibration data; (3) The name of the operator, the name of the person responsible for making the test, and the name of the test company used, if any; (4) The date and time of the test; (5) The minimum test pressure; (6) The test medium; (7) A description of the facility tested and the test apparatus; (8) An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts; (9) Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section; and (10) Temperature of the test medium or pipe during the test period.	x			

Comments:

BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(c)(3)	.404(a)	Operator shall maintain current maps and records of its pipeline systems that include at least the following information; (1) Location and identification of (i) breakout tanks.	x			
	.405(a)	Provide protection against ignitions arising out of static electricity, lightning, and stray currents IAW **API Recommended Practice 2003,** ***Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents,*** **(7th edition, January 2008).**	x			
	.405(b)	Review, consider, and incorporate into operator's procedure manual, the potentially hazardous conditions, safety practices and procedures associated with access/egress onto floating roofs IAW **API 2026,** ***Safe Access/Egress Involving Floating Roofs of Storage Tanks In Petroleum Service,*** **(2nd edition, April 1998, reaffirmed June 2006).**	x			
	.422	Repairs shall be made in a safe manner and made so as to prevent damage to persons or property.	x			
	.428(a)	Inspect and test each overfill protection system, pressure limiting device, relief valve, pressure regulator, or other pressure control equipment (annually/NTE 15 mo), except as provided in paragraph (b) of this section.	x			
	.428(b)	In the case of or relief valves on pressure breakout tanks containing **HVLs**, operator shall test each valve at intervals not exceeding 5 years.	x			
	.428(c)	Aboveground breakout tanks • constructed or significantly altered according to section 5.1.2 of **API Standard 2510** after October 2, 2000, must have an overfill protection system according to **5.1.2 of API Standard 2510, (8th edition, 2001).** • **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,*** **(3rd edition, January 2005).**	x			

BREAKOUT TANK INSPECTION FORM

	BREAKOUT TANK PROCEDURES		S	U	N/A	N/C
	.430	Each operator shall maintain adequate firefighting equipment at each 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.	x			
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **API Standard 653, (3rd edition December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008).** 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)**.	x			
		-Owner/operator visual, external condition inspection interval not to exceed **one month** (more frequent inspections may be needed based on conditions at particular sites)	x			
		-External inspection, visual, by an Authorized Inspector at least every **five years** or at the quarter corrosion rate life of the shell, whichever 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			
		Are corrosion rate-based internal inspection intervals established in accordance with API 653, and in no case exceed **20 years**? (Unless Risk-Based Inspection alternative is applied).	x			
		If tank bottom upper or lower side corrosion rate is unknown, the Out of Service inspection interval shall not exceed **10 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.**	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.	x			
	.434	Maintain signs visible to the public around each 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.	x			
	.436	Operator shall provide protection for each breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.	x			
	.438	Operator shall prohibit smoking and open flames in each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.	x			

Comments:

	Corrosion Control Procedures		S	U	N/A	N/C
.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** After 10/02/2000, required cathodic protection systems to protect above ground breakout tanks over 500 bbl capacity, shall be installed in accordance with **API RP 651, (3rd edition, January 2007).**	x			
	.571	**Cathodic Protection (CP) Acceptance Criteria** CP levels must comply with **NACE Standard RP0169-96** (paragraphs 6.2 and 6.3), **(reaffirmed March 15, 2007).**	x			
	.573(d)	**Breakout Tank CP inspections** Cathodic protection systems used to protect breakout tanks must be inspected in accordance with **API 651, (3rd edition, January 2007).**	x			
	11.3.2	**Cathodic Protection Surveys** – Annual CP surveys are required. Surveys may include one or more of the following:	x			

BREAKOUT TANK INSPECTION FORM

		Corrosion Control Procedures	S	U	N/A	N/C
		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			
	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			
	.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, API 620, API 650, or its predecessor 12C** must be installed in accordance with **API RP 652 (3rd edition, October 2005).**	X			
	.581(c)	**Atmospheric Corrosion Protection** Except for soil-to-air interfaces, atmospheric corrosion protection is not required where it is demonstrated by test, investigation, or similar environmental experience; that corrosion will – (1) Only be a light surface oxide; or (2) Not affect the safe operation of the pipeline before the next scheduled inspection.	X			
	.583(a)	**Atmospheric Corrosion Monitoring** Inspect each pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion at least once every 3 calendar years, but with intervals not exceeding 39 months.	X			
	.583(c)	If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.	X			

Comments:

BREAKOUT TANK INSPECTION FORM

FIELD REVIEW		S	U	N/A	N/C
.258(a)	Is each valve installed in a location that is accessible to authorized employees and protected from damage or tampering?	X			
.260(b)	A valve must be installed on each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.	X			
.264	Impoundment areas adequate, dikes not eroded, and dike drains operational.	X			
.428	Pressure Limiting Devices, relief valve, pressure regulator, overfill protection systems.	X			
.430	Each operator shall maintain adequate firefighting equipment at each breakout tank area that is: • In proper operating condition, • Plainly marked, and • Located to be readily accessible	X			
.434	Signs visible to the public around each breakout tank area that contains the name of the operator and a telephone number (including area code) where the operator can be reached at all times.	X			
.436	Protection for each breakout tank area from vandalism and unauthorized entry.	X			
.438	Prohibition of smoking and open flames in breakout tank areas	X			
.565	Cathodic Protection System Facilities	X			
.581	Atmospheric Corrosion (piping, tanks, soil/air interfaces, splash zones)	X			
.501-.509	**Operator Qualification -** Use PHMSA Form 15 Operator Qualification Field Inspection Protocol				

BREAKOUT TANK INSPECTION FORM

	RECORDS REVIEW	S	U	N/A	N/C
.132	Design and Construction of aboveground breakout tanks **(Notes: There were no new design and constructions during this inspection period.)**			x	
.205	Tank alteration and reconstruction records. For tanks repaired after 10/2/2000, records reflecting compliance with the referenced API standards. **(Notes: The last double bottom was completed in 2008.)**			x	
.264	Impoundment determination records. For tanks constructed after 10/2/2000, records reflecting compliance with the referenced API/NFPA standards. **(Notes: There were no tanks constructed after 10/2/2000.)**			x	
.264(d)	Record of calculations for normal/relief vents and pressure/vacuum vents.	x			
.310	Hydrostatic/pneumatic testing records for above ground breakout tanks for tanks first placed in service after 10/2/2000. **(Notes: There were no tanks first placed in service after 10/2/2000.)**			x	
.404	Maps and records of location and identification of breakout tanks	x			
.405(a)	API RP 2003 (if not followed by operator, must have a documented basis)	x			
.405(b)	Review applicable hazards in API RP 2026 for inclusion in the procedure manual	x			
.428	Testing of overpressure safety devices and overfill protection systems	x			
.432	Inspection of in-service breakout tanks (in accordance with applicable API Standard)				
	Monthly inspection reports	x			
	Annual inspection report(s) (not required if operator has implemented API 653 inspection program, but may be required by operator's O&M procedures).	x			
	In-service inspection report(s), including next inspection interval calculation	x			
	Out-of-service inspection report(s), including next inspection interval calculation **(Notes: There were no out-of-service inspections during this inspection period.)**			x	
	Follow-up actions from inspection findings (repairs, fill level height adjustments, other recommendations from inspection report).	x			
.573	External corrosion control monitoring records in accordance with API RP 651	x			
	Rectifiers (6 times per calendar year, not to exceed 2 ½ month intervals)	x			
	Electrical isolation and or bonds **(Notes: There were no electrical isolation or bonds in this unit.)**			x	
	Structure to Soil potentials, annual surveys	x			
.579	Tank bottom linings in accordance with API RP 652, if installed after October 2, 2000	x			
.581	Atmospheric corrosion monitoring (every 3 years not to exceed 39 months)	x			
.589	Current records or maps of cathodic protection and monitoring facilities, including galvanic anodes, installed after January 29, 2002, and neighboring structures bonded to CP systems.	x			

Comments:

There are two ground beds and one rectifier at this unit.

BREAKOUT TANK INSPECTION FORM

Breakout Tank Field Review (Complete one page for each tank or tank impound area inspected)						
.432	**Tank Number(s)**		**S**	**U**	**N/A**	**N/C**
	General Site Conditions	a. Runoff rainwater from the shell drains away from tank, and site drainage away from tank.	X			
		b. No vegetation against tanks, no flammable materials, trash.	X			
		c. No voids under tank/tank foundations, or settlement around perimeter of tank.	X			
	Tank Foundation, Bottom Shell	a. Concrete (no broken concrete, spalling, or cracks).	X			
		b. Plate and weld in bottom angle area (No thinning or corrosion).	X			
		c. Integrity of the bottom-to-foundation seal, if present.	X			
		d. No signs of bottom leakage.	X			
	External Shell	a. Exterior coating (No paint failure, pitting, or corrosion).	X			
		b. Rivet or seam leakage. **<u>(Notes: All tanks are with welded construction.)</u>**			X	
		c. No cracks or signs of leakage on weld joints at nozzles, manways, and reinforcing plates.	X			
		d. No shell deformation.	X			
		e. No shell plate dimpling around nozzles, caused by excessive pipe deflection.	X			
	Tank Piping and Manifolds	a. No manifold piping, flange, or valve leakage.	X			
		b. Anchored piping (check that it would not cause tank shell bottom connection damage during earth movement).	X			
		c. Adequate thermal pressure relief of piping to the tank.	X			
		d. Temperature indicators are accurate and undamaged.	X			
	Shell-Mounted Sample Station	a. Sample line and return-to-tank line valves, seals, and drains function properly. **<u>(Notes: There are no shell-mounted sample stations.)</u>**			X	
		b. Circulation pump has no signs of leaks or operating problems.			X	
	Mixer	a. Mounting flange is properly supported. **<u>(Notes: There are no mixers.)</u>**			X	
		b. No signs of leaks or operating problems.			X	
	Gauging System(s)	a. Verify proper operating condition	X			
		b. Evidence of operating problems	X			
	Inspection Recommendation(s) Follow-up	a. Have recommended actions from inspection reports been taken?	X			
		b. Have repairs identified by required inspections been made?	X			

Comments:

BREAKOUT TANK INSPECTION FORM

TANK DATA

	(See Note Below for * Items)	1	2	3	4	5	6
	FACILITY NAME(S):	Spokane Terminal	Spokane Terminal	Spokane Terminal	Spokane Terminal	Spokane Terminal	Spokane Terminal
*(A)	PRODUCT	R	R	R	R	R	R
(B)	TANK #	501	502	503	504	505	508
(C)	CONSTRUCTION YEAR and API STANDARD	1954, API 12C	1954, API 12C	1971, API 650	1954, API 12C	1954, API 12C	1957, API 12C
*(D)	CONSTRUCTION TYPE	W	W	W	W	W	W
(E)	CAPACITY (BBL)	43,166	35,194	63,729	47,842	35,017	38,733
(F)	LINING? (Y/N)	Y	Y	Y	Y	Y	Y
(G)	LINING TYPE?	Epoxy	Epoxy	Epoxy	Epoxy	Epoxy	Epoxy
(H)	TANK HT.(FT)	39'-6"	38'-1"	35'- 9 7/8"	39'-5"	38'-1"	39'-6"
(I)	MAX. FILL HT. (FT)	34'- 0"	34'-5"	36'-0-6"	37'-7"	34'-5-3"	34'-2"
(J)	DIA (FT)	95'	85'	112'	95'	85'	90'
*(K)	ROOF TYPE	IF	IF	IF	F	IF	IF
*(L)	VOLUMETRIC ALARM(S)	H, HH	H, HH	H, HH	H, HH	H, HH	H, HH
(M)	DIKE VOLUME (BBL)	100,853	103,164	100,853	103,164	100,853	103,164
*(N)	DATE LAST INTERNAL INSPECTION	8/17/2005	4/29/2008	10/2/2002	10/8/2007	5/5/2004	3/26/2003
*(O)	OUT OF SERVICE REPAIR OR OTHER MAJOR REPAIR	8/17/2005	4/29/2008 New Double Bottom	10/2/2002	10/8/2007 New Double Bottom	5/5/2004	3/26/2003
(P)	DATE API 653 APPLIED	8/17/2005	4/29/2008	10/2/2002	10/8/2007	5/5/2004	3/26/2003
*(Q)	CP TYPE & ANODE TYPE	R & Zinc Ribbon	R & Zinc Ribbon	R & Zinc Ribbon	R & Zinc Ribbon	R & Zinc Ribbon	R & Zinc Ribbon
*(R)	C P MONITORING	Reference cell buried between double bottoms & annual survey monitoring around circumference	Reference cell buried between double bottoms & annual survey monitoring around circumference	Reference cell buried between double bottoms & annual survey monitoring around circumference	Reference cell buried between double bottoms & annual survey monitoring around circumference	Reference cell buried between double bottoms & annual survey monitoring around circumference	Reference cell buried between double bottoms & annual survey monitoring around circumference
(S)	DUE DATE FOR NEXT INTERNAL INSPECTION?	2015	2018	2012	2017	2014	2013
(T)	INTERNAL INSPECTION INTERVAL? (YEARS)	10	10	10	10	10	10
*(U)	INTERNAL INSPECTION INTERVAL BASIS?	Maximum interval for new floor construction	Maximum interval for new floor construction	Maximum interval for new floor construction	Maximum interval for new floor construction	Maximum interval for new floor construction	Maximum interval for new floor construction
(V)	DUE DATE FOR NEXT EXTERNAL INSPECTION?	2015	2015	2015	2015	2015	2015
*(W)	EXTERNAL INSPECTION INTERVAL BASIS?	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval
(X)	DUE DATE FOR NEXT U. T. INSPECTION?	August 2015	July 2018	October 2012	August 2017	May 2014	March 2013
(Y)	SHELL U.T. INSPECTION INTERVAL	August 2015	July 2018	October 2012	August 2017	May 2014	March 2013
*(Z)	SHELL U.T. INSPECTION INTERVAL BASIS?	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval	Maximum API Interval

NOTE: Enter the applicable codes below in the table above:

(A): (R) Refined; (C) Crude; (HVL) Highly Volatile Liquid; (O) Other
(D): (W) Welded; (R) Riveted; (B) Bolted; Note if Tank is Insulated
(K): (EF) External Floater; (IF) Internal Floater; (F) Fixed

BREAKOUT TANK INSPECTION FORM

(L):	(H) High; (HH) High-High; (OF) Overfill; (O) Other
(N):	Most Recent Date
(O):	Most Recent Date
(Q):	(A) Anodic; (R) Rectified (N) None - Document why not needed.
(R):	(F) Fixed Reference Cells Under Floor; (S) CP Monitored at Edge of Shell
(U):	(C) Calculation (based upon known corrosion rate); (M) API Maximum Allowed Interval; (O) Other; (SS) Similar Service
(W):	(C) Calculation (based upon known corrosion rate); (M) API Maximum Allowed Interval; (O) Other; (SS) Similar Service
(Z):	(C) Calculation (based upon known corrosion rate); (M) API Maximum Allowed Interval; (O) Other; (SS) Similar Service

Comments:

PHMSA Pipeline Drug & Alcohol Questions

Instructions

1. Use in conjunction with Unit inspections
2. Interview the primary operator contact for the Unit inspection you are conducting and enter their responses. Do not request the operator substance abuse expert to provide responses to these questions.
3. Send completed form to stanley.kastanas@dot.gov

Name of Operator	Exxon Mobil Oil Corporation	**Op ID #**	32009
Inspector	Kuang Chu, / UTC	**Unit #**	10635
Date of Inspection	Oct 10-12, 2011		
Inspection Location City & State	Spokane, Washington, 99212		
Operator Employee Interviewed	**Larry Doc Hawthorne & Laura Sleevi**	**Phone #**	**509-534-8132**
Position/Title	**Pipeline Safety Advisor & Area Supervisor**		

Operator Designated Employer Representative (DER), (a.k.a. Substance Abuse Program Manager)	**Gary W. Hartman**
DER Phone #	**713-656-0227**

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes	No	Does Not Know
.3, .101 .201, .245	**1. Does the company have a plan for drug and alcohol testing of employees and contractors performing, or ready to perform, covered functions of operations, maintenance, and emergency response?**	x		
Comments	Page 38 or II-1 Appendix Page 135 of D& A Manual			
.3 .105(c) .225(b)	**2. Does the company perform random drug testing and reasonable suspicion drug and alcohol testing of employees performing covered functions? For random drug testing, enter the number of times per year employees are selected and the number of employees in each selection in Comments below.**	X		
Comments	PHMSA combined Reporting. Twice per year and total of 1131 employees.			
.3 .105(b)	**3. Does the company conduct post-accident/incident drug and alcohol testing for employees who have caused or contributed to the consequences of an accident/incident? Enter the position/title of the employee who would make the decision to conduct post-accident/incident testing in Comments below.**	x		
Comments	Area Supervisor and Relief for Area Supervisor- with input from Management			
.113(c) .117(a)(4) .227(b)(2) .241	**4. Does the company provide training for supervisors on the detection of potential drug abuse (minimum 60 minutes) and alcohol misuse (minimum 60 minutes)?**	X		
Comments	Training Record- WedCat or Mockingbird for Sleevi and Benard			
.3 .113(b) .117(a)(4) .239(b)(11)	**5. Does the company give covered employees an explanation of the drug & alcohol policies and distribute information about the Employee Assistance Program, including a hotline number? Provide details in Comments below.**	X		
Comments	EAP- Employee Assistance Program- Magellian 1-800-442-4123 page 126 of D &A Manual.			

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	October 12, 2011
Name of Operator:	ExxonMobil Corporation
Operator ID (OPID):	32009
Inspection Location(s):	Spokane, WA
Supervisor(s) Contacted:	Laura Sleevi
# Qualified Employees Observed:	2
# Qualified Contractors Observed:	None

Individual Observed	Title/Organization	Phone Number	Email Address
Dave Ort	West Coast Corrosion Control Coordinator	661-301-4272	Dave.port@exxonmobil.com
David Berard	Working Foreman	509-534-8132	David.j.berard@exxonmobil.com

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Kuang Chu	Western/WA	kchu@utc.wa.gov

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is on the last page of this form. This form is to be uploaded on to the OQBD for the appropriate operator, then imported into the file.

9.01 Covered Task Performance

Verify the qualified individuals performed the observed covered tasks in accordance with the operator's procedures or operator approved contractor procedures.

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.02 Qualification Status

Verify the individuals performing the observed covered tasks are currently qualified to perform the covered tasks.

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.03 Abnormal Operating Condition Recognition and Reaction

Verify the individuals performing covered tasks are cognizant of the AOCs that are applicable to the tasks observed.

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.04 Verification of Qualification

Verify the qualification records are current, and ensure the personal identification of all individuals performing covered tasks are checked, prior to task performance.

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected at the operational level?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Field Inspection Notes

The following table is provided for recording the covered tasks observed and the individuals performing those tasks.

		Name/ID of Individual Observed			
		Dave Ort	David Berard		
No	Task Name	Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	Comments
1	Reading Rectifiers	Y			
2	Conducting CP Annual Surveys	Y			
3	Monthly Inspection of Breakout Storage Tanks		Y		
4					
5					
6					
7					
8					

Operations and Maintenance Records Review

If performing an operations and maintenance records review in the course of your inspection, please review a sample of the qualifications of the individuals performing those O&M tasks that are covered under Operator Qualification and check the records for compliance to 192.807 or 195.507.

		Sat.	Unsat.	Not Checked
192.807 or 195.507	Records supporting an individual's current qualifications shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.	x		
	Comments:			

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

Hazardous Liquid IMP Field Verification Inspection
49 CFR Parts 195.450 and 195.452

General Notes:

1. This Field Verification Inspection is performed on field activities being performed by an Operator in support of their Integrity Management Program (IMP).
2. This is a two part inspection form:
   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 O&M and IMP Manuals 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.
3. 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. The applicable portions are identified in the Table below by a check mark. Only those sections of the form marked immediately below need to be documented as either "Satisfactory"; "Unsatisfactory"; or Not Checked ("N/C"). Those sections not marked below may be left blank.

Operator Inspected: <u>ExxonMobil Corporation</u>

Op ID: <u>32009</u>

Perform Activity *(denoted by mark)*	Activity Number	Activity Description
	1A	In-Line Inspection
	1B	Hydrostatic Pressure Testing
	1C	Other Assessment Technologies
	2A	Remedial Actions
	2B	Remediation – Implementation
	3A	Installed Leak Detection System Information
	3B	Installed Emergency Flow Restrictive Device
	4A	Field Inspection for Verification of HCA Locations
	4B	Field Inspection for Verification of Anomaly Digs
x	4C	Field Inspection to Verify adequacy of the Cathodic Protection System
x	4D	Field inspection for general system characteristics

Hazardous Liquid IMP Field Verification Inspection Form

Name of Operator: ExxonMobil Corporation

Headquarters Address: ExxonMobil Pipeline 800 Bell Street, Room 741-D Houston, TX 77002 **Company Official:** Laura Sleevi, Area Supervisor **Phone Number:** (509) 534-8132 **Fax Number:** (509) 534-8177 **Operator ID:** 32009

Persons Interviewed	Title	Phone No.	E-Mail
Laura Sleevi	**Rocky Mountain Area Supervisor Primary Contact**	(509) 534-8132	Laura.k.sleevi@exxonmobil.com
Larry Doc Hawthorne	Pipeline Safety Compliance Advisor	(903) 654-5345	Larry.e.hawthorne@exxonmobil.com
Dave Ort	West Coast Corrosion Control Coordinator	(661) 763-7616	Dave.p.ort@exxonmobil.com
Dave Berard	Working Foreman	(509) 534-8132	David.j.berard@exxonmobil.com
Emily Moeller	Field Engineer	(310) 212-3748	

OPS/State Representative(s): Kuang Chu/UTC **Dates of Inspection:** October 10, 11, 12 & 14, 2011

Inspector Signature: Kuang Chu, 11/3/2011

Pipeline Segment Descriptions: *[note: Description of the Pipeline Segment Inspected. (Include the pipe size, wall thickness, grade, seam type, coating type, length, pressure, commodities, HCA locations, and Pipeline Segment boundaries.)]*

The Spokane Terminal consists of six breakout tanks and associated piping. All the breakout tanks have been modified to double bottom and can re-inject products into the Yellowstone Pipeline. The terminal is primarily a truck loading facility. Ethanol and biofuel are transported to the terminal by rail tankers for blending.

Site Location of field activities: *[note: Describe the portion of the pipeline segment reviewed during the field verification, i.e. milepost/stations/valves/pipe-to-soil readings/river crossings/etc. In addition, a brief description and case number of the follow up items in any PHMSA compliance action or consent agreement that required field verification. Note: Complete pages 8 & 9 as appropriate.]*

All 6 breakout tanks and associated piping at the Spokane Terminal were reviewed during the field verification. The rectifier and all CP test points were inspected and pipe-to-soil potentials were taken. There were no IMP related field activities during this inspection.

Summary:

The field inspection included all six breakout tanks and associated piping at the Spokane Terminal. The API 653 In-Service inspection reports conducted by a certified tank inspector in August 2010 for all six tanks were reviewed.

Findings:

The thermowell for tank T-505 has been removed following the incident on November 3, 2008. A procedure for removing thermowell for calibration was developed for existing threaded thermowells. A new design for flanged thermowells has been developed by the operator. All threaded thermowells will be replaced by flanged thermowells whenever the tanks are undergoing an out-of-service internal inspection in the future. The cathodic protection for buried piping has been improved and meets code requirements. All 6 breakout tanks were externally inspected while in-service by a certified API 653 Inspector in August 2010. There were no probable violations found during this inspection.

Key Documents Reviewed:

Document Title	Document No.	Rev. No	Date
API 653 In-Service Inspection Reports			**8/2010**
Annual CP Survey			**2009/2010**
Tank Monthly Inspection Reports			**2009/2010**
Tank Annual Inspection Reports			**2009/2010**

Part 1 - Performance of Integrity Assessments

1A. In-Line Inspection (Protocol 3.04 & 3.05)	Satisfactory	Unsatisfactory	N/C	Notes: The piping at the terminal is non-piggable.
Verify that Operator's O&M and IMP procedural requirements (e.g. launching/receiving tools) for performance of ILI were followed.			x	
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, adequate transducer coverage), as appropriate.				
Document ILI Tool Vendor and Tool type (e.g. MFL, Deformation). Document other pertinent information about Vendor and Tool, as appropriate				
Verify that Operator's personnel have access to applicable procedures				
Other:				*[Note: Add location specific information, as appropriate.]*

1B. Hydrostatic Pressure Testing (Protocol 3.06)	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that hydrostatic pressure tests complied with Part 195 Subpart E requirements.	x			
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:				

1C. Other Assessment Technologies (Protocol 3.07)	Satisfactory	Unsatisfactory	N/C	Notes: The terminal does not use other assessment technologies to assess the integrity of the system.
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.			x	
Review documentation of notification to OPS of Operator's application of "Other Assessment Technology", if available. Verify compliance with Operator's procedural requirements. If documentation of notification to OPS of Operator's application of "Other Assessment Technology" is available, verify 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

2A. Remedial Actions – Process (Protocol 4.1)	Satisfactory	Unsatisfactory	N/C	Notes: There were no remedial actions at the terminal.
Verify that remedial actions complied with the Operator's procedural requirements.			x	
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 locating and exposing the anomaly (e.g. any required pressure reductions, line location, identifying approximate location of anomaly for excavation, 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.				
Verify that Operator's personnel have access to applicable procedures.				
Other:				

2B. Remediation - Implementation (Protocol 4.02)	Satisfactory	Unsatisfactory	N/C	Notes: There were no remedial actions at the terminal.
Verify that the operator has adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis.			x	
If documentation is available, 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 documentation for this inspection site 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.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: __________ mV Off Potential: __________ mV *[Note: Add location specific information, as appropriate.]*
Other:				

Part 3 - Preventive and Mitigative Actions

3A. Installed Leak Detection System Information (Protocol 6.05)	Satisfactory	Unsatisfactory	N/C	Notes: There is no leak detection system at the terminal.
Identify installed leak detection systems on pipelines and facilities that can affect an HCA.			x	
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:				*[Note: Add location specific information, as appropriate.]*

3B. Installed Emergency Flow Restrictive Device (Protocol 6.06)	Satisfactory	Unsatisfactory	N/C	Notes: There is no EFRD at the terminal.
Verify additional preventive and mitigative actions implemented by Operator.			x	
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.				
Verify operation of remote control valve by having operator send remote command to partially open or close the valve, 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:				*[Note: Add location specific information, as appropriate.]*

Part 4 - Field Investigations (Additional Activities as appropriate)

4A. Field Inspection for Verification of HCA Locations	Satisfactory	Unsatisfactory	N/C	Notes
Review HCAs locations as identified by the Operator. Utilize NPMS, as appropriate.	x			Notes: The terminal is in HCA as it is on top of the drinking water aquifer in Spokane.
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, as appropriate. 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				*[Note: Add location specific information, as appropriate.]*

4B. Field Inspection for Verification of Anomaly Digs	Satisfactory	Unsatisfactory	N/C	Notes:
Verify repair areas, ILI verification sites, etc.	x			
Document the anomaly dig sites reviewed as part of this field activity and actions taken by the operator.				*[Note: Add location specific information, as appropriate.]*

4C. Field Inspection to Verify adequacy of the Cathodic Protection System	Satisfactory	Unsatisfactory	N/C	Notes:
In case of hydrostatic pressure testing, Cathodic Protection (CP) systems must be evaluated for general adequacy.	x			
The operator should review the CP system performance in conjunction with a hydrostatic pressure test to ensure the integrity assessment addressed applicable threats to the integrity of the pipeline. Has the operator reviewed the CP system performance in conjunction with the hydrostatic pressure test?				
Review records of CP readings from CIS and/or annual survey to ensure minimum code requirements are being met, if available.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: _______________mV Off Potential: _______________mV
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.				*[Note: Add location specific information, as appropriate.]*

4D. Field inspection for general system characteristics	Satisfactory	Unsatisfactory	N/C	Notes:
Through field inspection determine overall condition of pipeline and associated facilities for a general estimation of the effectiveness of the operator's IMP implementation.	x			
Evaluate condition of the ROW of inspection site 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				

Anomaly Evaluation Report *(to be completed as appropriate)*

Pipeline System and Line Pipe Information	
Operator (OpID and System Name):	
Unit ID (Pipeline Name)	
Pipe Manufacturer and Year:	Seam Type and Orientation:
Pipe Nominal OD (inch):	Seam Orientation:
Pipe Nominal Wall thickness (inch):	Coating Type:
Grade of Pipe:	MOP:
ILI Reported Information	
ILI Technology (e.g., Vendor, Tools):	
Anomaly Type (e.g., Mechanical, Metal Loss):	
Is anomaly in a segment that can affect an HCA? (Yes / No)	
Date of Tool Run (MM/DD/YY): Date of Inspection Report (MM/DD/YY):	
Date of "Discovery of Anomaly" (MM/DD/YY):	
Type of "Condition" (e.g.; Immediate; 60-day; 180-day):	
Anomaly Feature (Int/Ext): Orientation:	
Anomaly Details: Length (in): Width (in): Depth (in):	
Anomaly Log Distance (ft): Distance from Upstream weld (ft):	
Length of joint of pipe in which anomaly is identified (ft):	
Anomaly Dig Site Information Summary	
Date of Anomaly Dig (MM/DD/YY):	
Location Information:	
Mile Post Number: Distance from A/G Reference (ft):	
Distance from Upstream weld (ft):	
GPS Readings (if available) Longitude: Latitude:	
Anomaly Feature (Int/Ext): Orientation:	
Length of joint of pipe in which anomaly is found (ft):	
For Mechanical Damage Anomaly	
Damage Type (e.g., original construction, plain dent, gouge):	
Length (in): Width (in): Depth (in):	
Near a weld? (Yes / No):	
Gouge or metal loss associated with dent? (Yes / No):	
Did operator perform additional NDE to evaluate presence of cracks in dent? (Yes / No):	
Cracks associated with dent? (Yes / No):	
For Corrosion Metal Loss Anomaly	
Anomaly Type (e.g., pitting, general):	
Length (in): Width (in): Max. Depth (in):	
Remaining minimum wall thickness (in): Maximum % Wall Loss measurement(%):	
Safe pressure calculation (psi), as appropriate:	
For "Other Types" of Anomalies	
Describe anomaly (e.g., dent with metal loss, crack, seam defect, SCC):	
Length (in): Width (in): Max. Depth (in):	
Other Information, as appropriate:	
Did operator perform additional NDE to evaluate presence of cracks? (Yes / No):	
Cracks present? (Yes / No):	

Anomaly Repair Report *(to be completed as appropriate)*

Repair Information		
Was a repair of the anomaly made? (Yes / No):		
Was defect ground out to eliminate need for repair? (Yes / No):		
If grinding used, complete the following for affected area: Length (in):	Width (in):	Depth (in):
If NO repair of an anomaly for which RSTRENG is applicable, were the Operator's RSTRENG calculations reviewed? (Yes / No):		
If Repair made, complete the following:		
Repair Type (e.g., Type B-sleeve, composite wrap)		
Length of Repair:		
Comments on Repair material, as appropriate (e.g., grade of steel):		
Pipe re-coating material used following excavation:		
General Observations and Comments		
Was a diagram (e.g., corrosion map) of the anomaly made? (Yes / No):		(Include in report if available)
Were pipe-to-soil cathodic protection readings taken? (Yes / No):		
If readings taken, Record: On Potential: ____________ mV; Off Potential: ____________ mV		
Describe method used to Operator to locate anomaly (as appropriate):		
Comments regarding procedures followed during excavation, repair of anomaly, and backfill (as appropriate):		
General Observations and Comments *(Note: attach photographs, sketches, etc., as appropriate)*:		

Field Data Collection
(2011Standard Inspection)

Company: ExxonMobil Corporation

Unit: Spokane Terminal

Pipe-to-Soil Potential Readings, Rectifiers, and Others

Date	Location	Pipe (Volts) Power On	Pipe (Volts) Power Off	Casing (Volts)	Comments
10/12/2011	Yellowstone Manifold Area				
	Test Point #24	-1.563			
	Test Point #25	-1.346			
	Test Point #26	-1.203			
	Test Point #27	-1.107			
	Test Point #28	-1.105			
	Test Point #29	-1.178			
	Test Point #30	-1.179			
	Test Point #31	-1.115			
	Test Point #32	-1.129			
	Test Point #33	-1.096			
	Test Point #34	-1.139			
	Test Point #35	-1.152			
	Test Point #36	-1.484			
	Test Point #37	-1.175			
	Test Point #38	-1.186			
	Test Point #39	-1.236			

	Test Point #40	-1.360			
10/12/2011	Products Transfer Area Test Point #1 Test Point #2 Test Point #4 Test Point #5 Test Point #6 Test Point #7 Test Point #8	 -1.362 -1.359 -1.369 -1.375 -1.374 -1.347 -2.461			The piping at test point #3 is no longer in service.
10/12/2011	The only rectifier at the terminal				DC output: 101.5 V; 33.7 A
10/12/2011	Tank T-502 chime South West North East	 -1.414 -2.127 -1.625 -1.440			
10/12/2011	Tank T-508 chime South West North East	 -1.348 -1.322 -1.359 -1.497			
10/12/2011	Tank T-504 chime South West North East	 -1.361 -2.075 -1.940 -1.823			
10/12/2011	Tank T-501 chime North East South West	 -1.479 -1.111 -1.127 -1.790			
10/12/2011	Tank T-503 chime South East	 -1.424 -1.114			

	North West	-1.442 -1.150			
10/12/2011	Tank T-505 chime South East North West	 -1.663 -1.930 -2.601 -1.491			

PUBLIC AWARENESS PROGRAM FIELD AUDIT

Audit Date: Oct 10, 11, &12, 2011	**Name of Operator:** ExxonMobil Oil Corporation
H.Q. Address 800 Bell St Room 603-L Houston, Texas 77002	**Company Official:** Larry Hawthorne **Title:** Pipeline Safety Advisor **Phone number:** 903-654-5345 **Fax Number:** 903-654-5302
Inspection Team:	**Operator Personnel in Interview: (Name & Phone Number)**
1. Kuang Chu, UTC	1. Laura Sleevi 509-534-8132
2.	2. Larry Doc Hawthorne 903-654-5345
3.	3. Dave Benard (4) Dave Ort (5) Emily Moeller

Instructions: Check (or mark) the appropriate box: "Yes," "No" or "N/A." If further comments are necessary, check (or mark) the comment box and write the comment in the "comments" section below the questions and/or attach a comments sheet when necessary. **These questions are to be verified in the field. Certain questions will have corresponding Desk Audit questions on a separate audit form.**

		Yes	No	N/A	Comment
1.	**1162 Section 2: Management Commitment** **(Must be verified in field if no PHYSICAL copy included in plan)**				
	a. Does the statement include the name and title of the appropriate authority (the person(s) with authority to authorize funding)? Page 9	X			
	b. Does the statement include the signature of the appropriate authority (the person(s) with authority to authorize funding)?	X			
	c. Are copies of approved city ordinances, etc., included where applicable			X	
2.	**1162 Section 4: Message Content** **(These are required in written plan. They will need verification in field)**				
Affected Public: Including customers & residents living along the pipeline route	a. pipeline purpose and reliability	X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]				
	c. leak recognition and response [192.616(d)(3 &4)]	X			
	d. damage prevention awareness	X			
	e. how and where to get more information	X			
	f. One-call requirements [192.616(d)(1)]	X			
	g. Emergency communications [192.616(d)(5)]	X			
Emergency Officials	a. pipeline purpose and reliability	X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]	X			
	c. leak recognition and response [192.616(d)(3 &4)]	X			
	d. emergency preparedness and response	X			
	e. how and where to get more information	X			
	f. emergency communications [192.616(d)(5)]	X			
	g. One-call requirements [192.616(d)(1)]	X			

Comments:

		Yes	No	N/A	Comment
2. (Continued)	**1162 Section 4: Message Content** **(These are required in written plan. They will need verification in field)**				
Local Public Officials	a. pipeline purpose and reliability	x			
	b. hazards & prevention measures undertaken [192.616(d)(2)]	x			
	c. leak recognition and response [192.616(d)(3 &4)]	x			
	d. emergency preparedness and response	x			
	e. right-of-way encroachments	x			
	f. how and where to get more information	x			
	g. emergency communications [192.616(d)(5)]	x			
	h. construction/maintenance activities	x			
	i. One-call requirements [192.616(d)(1)]	x			
Excavators/ Contractors	a. pipeline purpose and reliability	x			
	b. hazards & prevention measures undertaken [192.616(d)(2)]	x			
	c. leak recognition and response [192.616(d)(3 &4)]	x			
	d. damage prevention awareness	x			
	e. pipeline location information	x			
	f. how and where to get more information	x			
	g. One-call requirements [192.616(d)(1)]	x			
	h. emergency communications [192.616(d)(5)]	x			
3.	**1162 Section 4 (4.4.1): PRIORITY MESSAGE** **(Message should be written in plan and verified in Field) Does the program identify the message for Emergency and Public Officials as protecting people first and then property as the TOP priority message?**	X			

Comments:
These words or emphasis should be written in plan:
Message should be written in plan and verified in Field. Does the program identify the message for Emergency and Public Officials as protecting people first and then property?

Doc Hawthorne- Pipeline Safety Advisor will review plan for priority message and contact Program Administrator of change to manual.

		Yes	No	N/A	Com-ment
4.	**1162 Section 5: Delivery Method**				
Affected Public:	**(From written plan – Does operator provide applicable documentation?)**				
LDC Customers	1. Bill Stuffer – required minimum			x	
Baseline	1. Public service announcements			x	
	2. Paid Advertising			x	
	3. Other:			x	
Supplemental	1. Public service announcements			x	
	2. Paid advertising			x	
	3. Targeted distribution of print material			x	
	4. Newspaper and magazine advertisements			x	
	5. Community events			x	
	6. Community newsletters			x	
	7. Other:			x	
Emergency Officials:	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Print Materials-	x			
	2. Group Meetings	x			
	3. Other- (Good Neighbor Grant Program) each year	x			
Supplemental:	1. Telephone calls- (PL-2339 form available)	x			
	2. Personal contact	x			
	3. Videos and/or CDs (available from Public Affairs)	x			
	4. Other: LEPC meetings-	x			
Local Public Officials:	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Targeted distribution of printed materials			x	
	2. Other			x	
Supplemental:	1. Group meetings			x	
	2. Telephone calls			x	
	3. Personal contact			x	
	4. Other- Drills-	x			
Excavators/ Contractors	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Once-Call center outreach – One Call Center for Excavation	x			
	2. Group meetings			x	
	3. Other -	x			
Supplemental	1. Personal contact			x	
	2. Videos and/or CDs			x	
	3. Open houses			x	
	4. Targeted distribution of print materials	x			
	5. Other-			x	

Comments: One call are made for any excavation inside the fence.
Contractor Work shop conducted each year with Contractors.

		Yes	No	N/A	Com-ment
5.	**1162 Section 5: Delivery Frequencies** **(These are required in the written plan)**				
Affected Public:					
LDC Customers?	Does documentation show at least twice per year?			x	
Residents along the LDC system?	Does documentation show at least once per year?			x	
Emergency Officials	Does documentation show at least once per year?	x			
Local Public Officials	Does documentation show at least once every three years?	x			
Excavators/ Contractors	Does documentation show at least once per year?	x			

		Yes	No	N/A	Com-ment
6.	**1162 Section 6: Supplemental messages:** **Does the plan consider whether supplemental messages are necessary for special circumstances and explain why or why not? (These will need to be verified in field where applicable)**	x			
	Circle the examples below that apply:				
	1. Large excavator projects				
	2. Non-resident business owners (i.e., just workers occupy buildings(s) - owner that receives bill is in another location and/or state and tenant farmers)				
	3. Farming activities				
	4. Railroads				
	5. Other				
7.	**1162 Section 7: Program Implementation**				
	Is there documentation verifying the program has been implemented?	x			

		LDC Public	Emer. Ofls	Pub. Ofls	Excavator/ Contractor	N/A	Com-ment
8.	**1162 Section 7: Recordkeeping**						
	Can the Operator Document the following: (Write "Y" for Yes" and "N" for No under each applicable stakeholder audience)						
	a. Lists, Records and other documentation of stakeholder audiences?	x					
	b. Copies of all materials used?	x					
	c. Records of payments for mailings, advertisements, printing and other expenditures indicating the program was implemented?	x					
	d. Records of effectiveness assessments?	x	x	x	x		API
	e. Records of annual assessments and/or audits?	x	x	x	x		
	f. Any record of feedback received and collected from audiences in response to the program?	x	x	x	x		
	g. Records of follow-up actions and expected results	x	x	x	x		
	h. Have records been maintained for five (5) years?	x	x	x	x		

Comments: Record of assessment conducted yearly under OIMS 10A

		Yes	No	N/A	Com-ment
9.	**1162 Section 8: ANNUAL REVIEW** **(This is required in the written plan – needs field documentation.)**				
	a. Does the annual audit ensure the Plan meets the minimum requirements of the regulation?	X			
	b. Does the annual audit ensure all actions called for in the Plan have been carried out as specified in the Plan?	X			
	c. Are records of the annual audit maintained by the Program Administrator?	X			
10.	**1162 Section 8: Evaluation Results**				
	Has the operator issued the results of the evaluation (review), shared it with upper management and sought internal feedback?	X			
11.	**1162 Section 8: Continuous Improvement Conducted:**				
	a. Has the operator modified its program based on its evaluation?	X			
	b. Are these changes documented?	X			
	c. Have these changes been implemented?	X			
	COMMENTS:				
12.	**1162 Section 8: Effectiveness Assessment** **(This is required upon design or re-design of materials and/or messages)**				
	a. Pre-tested Materials:				
	b. Date Pre-test conducted:	X			
13.	**1162 Section 8: Effectiveness Assessment** **(Required to be done no more than FOUR years apart)**				
	a. Last Survey of Targeted Audiences::				
	b. Date of last effectiveness assessment:				
	c. Has the operator documented the results of evaluating the program for effectiveness?	X			
	Explain: OIMS 10 Plan has annual review of Public Awareness Plans				

Comments: