4/7/04

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: ExxonMobil Pipeline Company	
H.Q. Address: 800 Bell Street Houston, TX 77002	**System/Unit Name and Address:** Unit AR no local address
Co. Official: A. K. Turner, Vice President Operations **Phone No.:** 713-656-2227 **Fax No.:** 713-656-2170 **Emergency Phone No.:** 1-800-537-5200 **Operator ID#:** 4906	**Phone No.:** N/A **Fax No.:** N/A **Emergency Phone No.:** 1-800-537-5200 **Unit Record ID#:** 1191 **Activity Record ID#:** 102839

Persons Interviewed	Titles	Phone No.
Mike Adams	Pipeline Safety Advisor	713-656-3926
Denny Wedgeworth	Corrosion Technician	903-236-8141
Gary J. Sigle	Maintenance-Operations Tech.	870-542-6221
Dale P. Comeaux	Operations Supervisor	903-654-5331
Irvin Eddington	Pipeliner	573-996-2516

OPS Representative(s): Joseph Mataich **Date(s):** Sept. 16-18, 2003

Company System Maps (copies for Region Files): on file

Unit Description:

296 miles of single 20" pipeline (crude oil line currently out of service). Unit runs from the Red River at the Arkansas/Texas border to the Arkansas/Missouri border. Four pump stations; Foreman, Glenwood, Conway and Strawberry.

Pipeline was taken out of service and put under a nitrogen purge in December, 2002. No immediate plans for putting line back in service.

Portion of Unit Inspected:

All pump stations and multiple points along the ROW. Records were brought to Foreman Station for review.

The O&M Manual was not reviewed in detail. A Team O&M Inspection was done November 4-8, 2002. No revisions have been made to the O&M Manual since the Team Inspection.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

HVL PIPELINE TESTING SUMMARY	N/A	Yes	No
1. Do the operator's pipelines transport HVLs?			x
2. Has the operator pressure tested the following "older" HVL pipelines per subpart E; or, for pipelines that have not been converted under 195.5, has the operator established these pipelines' MOP's per 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]? **The pressure test and MOP establishment (195.406(a)(5)) deadlines for the below listed lines have passed.**	x		
a. Onshore non low stress Interstate Lines in HVL service prior to 9/8/80 and constructed prior to 1/8/71.	x		
b. Onshore non low stress Intrastate Lines in HVL service prior to 4/23/85 and constructed prior to 10/21/85.	x		
c. Low stress lines in HVL service that existed on 7/12/94, or ones that were constructed before 8/11/94.	x		

PIPELINE INFORMATION

Boundaries of Unit:

Texas/Arkansas state line at the Red River to Arkansas/Missouri state line.

Pipelines and Pumping Stations in Unit:

One 20" crude oil pipeline, 296 miles.
Four pump stations; Formen, Glenwood, Conway and Strawberry.

Miles of Pipeline:	Protected				Unprotected			
Steel Bare								
Steel Coated	296							
Other								

Breakout Tank Facilities:

No breakout tanks.

Offshore Facilities:

N/A

	Conversion to Service	S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				x

Comments *(If the above is Unsatisfactory, please indicate why):*

		Subpart B - Reporting Procedures	S	U	N/A	N/C
.402 (c)(2)		Does the operator have procedures for gathering data needed for reporting accidents under **Subpart B** of this part in a timely and effective manner?				x
	.50	Does the operator file accident reports as required under 195.50? Under certain conditions, a release of more than 5 gals, or more is reported.				x
	.52	Are certain incidents telephonically reported to the **National Response Center**?				x
	.54	Are the incidents reported by telephone followed up with a 30-day written report?				x
.402(f)		Does the operator have procedures for recognizing and discovery of safety-related conditions?				x
	.55	If the operator reported a safety-related condition, did they use the proper criteria?				x
	.56	Is there a procedure for reporting safety-related conditions?				x
	.56(a)	Was the report filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery?				x
	.56(b)	Was proper corrective action taken?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		Subpart C - Passage of Internal Inspection Device Procedures	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Has each new pipeline or each section of a pipeline which pipe or components has been replaced been designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		Subpart D - Welding 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, as well as §195.200.				
.402(c)/ .422	**.214(a)**	Is the welding performed in accordance with welding procedures qualified to produce welds meeting the requirements of this **Subpart**?				x
		Has the quality of the test welds to qualify the procedures been determined by destructive testing?				x
	.214(b)	Is each welding procedure recorded in detail?				x
		Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**				x
	.222	Is welding performed by welders, who have been qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition?				x
Alert Notice 3/13/88		**In the welding of repair sleeves and fittings, does the operator's procedures give consideration to:**				
		1. The use of low hydrogen welding rods.				
		2. Cooling rate of the weld.				
		3. Metallurgy of the materials being welded (weldability carbon equivalent).				
		4. Proper support of the pipe in the ditch.				
.402(c)/ .422	**.226(a)**	Does the operator require the repair (within pipe and (b) specification thickness tolerances) or replacement of arc burns?				x
	.226(b)	Does the operator require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**				x
	.226(c)	When pipe is being welded, is the ground wire attached to the pipe by other means than welding?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Welds: Acceptability - Nondestructive Testing Procedures			S	U	N/A	N/C
.402(c)/ .422	.228	Does the operator nondestructively test welds to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?				x
	.234(b)	Is nondestructive testing of welds 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	Does the operator maintain records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Welds: Repair or Removal of Defect Procedures			S	U	N/A	N/C
.402(c)/ .422	.230	Does the operator remove and/or repair welds that are unacceptable in accordance with the requirements of **§195.230**?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Subpart E - Pressure Testing Procedures			S	U	N/A	N/C
.402(c)/ .422	.302(a)	Does the operator pressure test each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced?				x
		Are lines that have not been pressure tested per subpart E being operated in accordance with this subsection?				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] ?				x
		- 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
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				x
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				x
	.303	Does the operator comply with the risk based alternative to pressure testing?				x
	.304	The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure.				x

		Subpart E - Pressure Testing Procedures (Con't)	S	U	N/A	N/C
402(c)/ .422	.305(a)	Does the operator pressure test under **§195.302** all pipe, all attached fittings, including components?				x
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				x
	.306	Is the appropriate test medium used?				x
	.308	Does the operator pressure test pipe associated with tie-ins as one segment or tested separately?				x
	.310(a)	Does the operator maintain a record of each pressure test required by this **Subpart**?				x
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				x
	.310(b)(2)	Test instrument calibration data.				x
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				x
	.310(b)(4)	Date and time of the test.				x
	.310(b)(5)	Minimum test pressure.				x
	.310(b)(6)	Test medium.				x
	.310(b)(7)	Description of the facility tested and the test apparatus.				x
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				x
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included.				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		Subpart F - Operations & Maintenance Procedures	S	U	N/A	N/C
.402(a)	.402	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				x
		b. Does the operator review the manual at intervals not exceeding 15 months, but at least each calendar year?	x			
		c. Are the manuals available, as required?	x			

Comments *(If any of the above is Unsatisfactory, please indicate why):*
.402: O&M Manual was not reviewed in detail because Team O&M Inspection was completed Nov. 2002. Verified that O&M Manual is being reviewed and updated as required. Operator had a marked up copy of the O&M Manual, to be published by the end of calendar year 2003.

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
	.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 *(If any of the above is Unsatisfactory, please indicate why)*:

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:				

			S	U	N/A	N/C
		i. Unintended closure of valves or shutdowns?				x
		ii. An increase or decrease or flow rate outside normal operating limits?				x
		iii. Loss of communications?				x
		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 *(If any of the above is Unsatisfactory, please indicate why):*

		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.?				x
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				x
	.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 *(If any of the above is Unsatisfactory, please indicate why):*

		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 operating and maintenance, and 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
	.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 proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus, etc.				x
	.402(f)	Recognize and report safety related conditions.				x
	.403(b)	At intervals not exceeding 15 months, but at least once each calender year:				
	.403(b)(1)	Does the operator review with personnel their performance in meeting the objectives of the emergency response training program?				x
	.403(b)(2)	Does the operator make appropriate changes to the emergency response training program?				x
	.403(c)	Does the operator require and verify, its supervisors maintain a thorough knowledge of the emergency response procedures they are responsible for?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		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				x
		iv. Pipeline valves				x
		v. Facilities to which **§195.402(c)(9)** applies				x
		vi. Rights-of-way				x
		vii. Safety devices to which **§195.428** applies				x
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				x
	.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**.				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

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**.				x
	.406(a)(2)	The design pressure of any other component on the pipeline.				x
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				x
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				x
	.406(a)(5)	**80%** of the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				x
	.406(b)	The pipeline may not be operated at a pressure that exceed **110% of the MOP**:				
		a. Are adequate controls and protective equipment installed to prevent the pressure from exceeding **110%** of the **MOP**?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Line is out of service, under a nitrogen purge and being maintained at approximately 200 psig.

Communication Procedures (Control Center)			S	U	N/A	N/C
.402(a)	.408(a)	Does the operator 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)**.				x
	.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.				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Line Marker Procedures			S	U	N/A	N/C
.402(a)	.410(a)	Each operator shall place and maintain line markers over each buried pipeline in accordance with the following:				

			S	U	N/A	N/C
	.410(a)(1)	Are line markers placed at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known?				x
	.410(a)(2)	Do the line markers have the correct characteristics and information?				x
	.410(c)	Are line markers placed where pipelines are aboveground in areas that are accessible to the public?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Inspection of Rights-of-Way & Crossings Under Navigable Water Procedures			S	U	N/A	N/C
.402(a)	.412(a)	Does the operator inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**?				x
		Does the operator follow-up on problems noted by the patrol?				
	.412(b)	Does the operator inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Underwater Inspection Procedures of Offshore Pipelines			S	U	N/A	N/C
.402(a)	.413(b)	When the operator discovers a pipeline, it operates, is exposed on the seabed or constitutes a hazard to navigation does the operator:				
	.413(b)(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.			x	
	.413(b)(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			x	
	.57	Has the operator **filed** a report within **60 days** of the inspection as required by **§195.413**?			x	

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Valve Maintenance Procedures			S	U	N/A	N/C
.402(a)	.420(a)	Does the operator maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times?				x
	.420(b)	Does the operator 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)	Does the operator provide protection for each valve from unauthorized operation and from vandalism?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		Pipeline Repair Procedures	S	U	N/A	N/C
.402(a)	.422(a)	Does the operator, 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 *(If any of the above is Unsatisfactory, please indicate why):*

		Pipe Movement Procedures	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, does the operator reduce the pressure for the line segment involved to **50% of the MOP**.				x
	.424(b)	For **HVL** lines **joined** by welding, does the operator:				
	.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 **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, does the operator:				
	.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 *(If any of the above is Unsatisfactory, please indicate why):*

Scraper and Sphere Facility Procedures			S	U	N/A	N/C
.402(a)	.426	Does the operator, have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres?				x
		Does the operator have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion?				x

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

Overpressure Safety Device Procedures			S	U	N/A	N/C
.402(a)	.428(a)	Does the operator 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?				x
		Does the operator 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)	Does the operator inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**?				x
	.428(c)	Do 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 the appropriate API. 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 *(If any of the above is Unsatisfactory, please indicate why)*:

Firefighting Equipment Procedures			S	U	N/A	N/C
.402(a)	.430	Does the operator maintain adequate firefighting equipment at each pump station and breakout tank areas?				x

	.430	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 *(If any of the above is Unsatisfactory, please indicate why):*

		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	
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).			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	
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Sign Procedures			S	U	N/A	N/C
.402(a)	.434	Does the operator maintain signs visible to the public around each pumping station and breakout tank area?				x
		Do the signs contain the name of the operator and an emergency telephone number?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Security of Facility Procedures			S	U	N/A	N/C
.402(a)	.436	Does the operator provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry?				x

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Smoking or Open Flame Procedures			S	U	N/A	N/C
.402(a)	.438	Does the operator 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?				x

Comments *(Ifany of the above is Unsatisfactory, please indicate why):*

Public Education Procedures			S	U	N/A	N/C
.402(a)	.440	Has the operator established a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?	x			
		Is the program conducted in English and other languages where appropriate?	x			

Comments *(If any of the above is Unsatisfactory, please indicate why):*
.440 Operator is using The Pipeline group for public awareness meetings. The Operator indicated that the Arkansas One Call Program is in the process of developing a public awareness program and will be holding meetings similar to what The Pipeline Group does. The Operator may be using the Arkansas One Call public awareness meeting in the future rather than using The Pipeline Group.

		Damage Prevention Program Procedures	S	U	N/A	N/C
.402(a)	.442(a)	Does the operator have 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 current a 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.				x
	.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 frequency 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.				x

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

		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?			x	

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

Pipeline out of service.

High Consequence Areas & Pipeline IMP Procedures		S	U	N/A	N/C
§195.450 & §195.452	These sections are being addressed by the OPS IMP group.				

Subpart G - Operator Qualification Procedures		S	U	N/A	N/C
§195.501-509	Refer to Operator Qualification Protocols				x

Subpart H - Corrosion Control Procedures			S	U	N/A	N/C
.402(a)	.555	Does the Operator require and verify that supervisors maintain a through 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 :				x
		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.				x
	.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.				x
		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-				x
		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

		Subpart H - Corrosion Control Procedures (Con't)	S	U	N/A	N/C
.402(a)		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	
	.567	Test leads installation and maintenance				x
	.569	Examination of Exposed Portions of Buried Pipelines				x
	.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)				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 RP0169-96.				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, 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.			x	
		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 2 ½ months.				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? What steps are taken to minimize internal corrosion.				x
	.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.				x
		OFFSHORE - At least once each year, but at intervals not exceeding 15 months.			x	

		Subpart H - Corrosion Control Procedures (Con't)	S	U	N/A	N/C
.402(a)	.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
	.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 *(If any of the above is Unsatisfactory, please indicate why):*

Best Practice:
Are the breakout tanks equipped with high level alarms?

Comments:

N/A No breakout tanks

Note:
How often are they checked?
Is the check all the way back to the SCADA center to ensure the hardware between the sensor and SCADA is good?

Best Practice:

Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

Comments: Yes, the Operators local management or project engineering personnel would be working closely with any contractors working near the ROW. The Operator has developed an orange placard containing contact information. The placard is left at unattended job sites to instruct contractor personnel on contacting the Operator to set up a meeting.

Best Practice:

Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

Comments: Yes, any school within 1000' of the ROW would be addressed in the Operator's program.

Best Practice:

Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

Comments: Yes, the Operator's public awareness team reviewed the study when it was first published.

Best Practice:

Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

Comments:

Yes

Best Practice:
Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

Comments: The Operator has established a full time position of "Damage Prevention Coordinator".

Best Practice:
Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

Comments: Yes, the Operator's Public Relations Advisor is a member of the API committee on Public Education. The Operator interfaces with other industry members through this API committee.

Best Practice:
Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities?

Comments: Yes, this is covered in the O&M Manual.

Best Practice:
NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

Comments: Yes, Operator's personnel are used for locating. *Note: Are contractors used? What does their training consist off? How is quality control ensured when using a third party?*

Best Practice:

- **What factors are considered in determining the need for and timing of pigging and close interval surveys?**

Comments: Smart pigging is being done per the Operator's Integrity Management Program. Close interval survey's are based on an engineering evaluation.

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.120	Have new pipelines, or pipeline sections of which pipe or components have been replaced, been designed and constructed to accommodate smart pigs ? (See exceptions under (b) and (c))			x	
.262	Pumping Stations	x			
.262	Station Safety Devices	x			
.308	Pre-pressure Testing Pipe - Marking and Inventory				x
.403	Knowledge of Operating Personnel	x			
.410	Right-of-Way Markers	x			
.412	River Crossings	x			
.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)	x			
.573	Pipeline Components Exposed to the Atmosphere	x			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	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			

PART 195 - RECORDS REVIEW		S	U	N/A	N/C
	Conversion to Service				
.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)			x	
.5(a)(2)	Inspection of Pipeline Right-of-Way			x	
.5(c)	Pipeline Records (Life of System)			x	
	Pipeline Investigations			x	
	Pipeline Testing			x	
	Pipeline Repairs			x	
	Pipeline Replacements			x	
	Pipeline Alterations			x	
	Reporting				
.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	

	PART 195 - RECORDS REVIEW (con't)	S	U	N/A	N/C
	Operation & Maintenance				
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions			x	
.402(c)(10)	Abandonment of Facilities			x	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Emergency Agencies	x			
.402(c)(13)	Review of work Performed by Personnel	x			
.402(d)(1)	Response to Abnormal Pipeline Operations			x	
.402(d)(5)	Review of Personnel Response to Abnormal Operations			x	
.402(e)(1)	Notices of Emergencies			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)	Employee Training	x			
.403(b)	Annual Review of Personnel Performance	x			
.403(c)	Verification of Supervisor Knowledge	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	x			
.404(b)(2)	Abnormal Operations (§195.402)			x	
.404(c)(1)	Pipe Repairs			x	
.404(c)(2)	Repairs to Parts of the System other than Pipe			x	
.406(a)	Establishing the MOP				x
.412(a)	Inspection of the ROW	x			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	x			
.413(b)	Inspection of Pipelines in Gulf of Mexico			x	
.420(b)	Inspection of Mainline Valves	x			
.428(a)	Inspection of Overpressure Safety Devices	x			
.428(b)	Inspection of Relief Devices on HVL Tanks			x	
.430	Inspection of Fire Fighting Equipment	x			
.432	Inspection of Breakout Tanks			x	
.440	Public Education	x			

PART 195 - RECORDS REVIEW (Cont.)		S	U	N/A	N/C
	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				
.569	Inspection of Exposed Pipelines (External Corrosion)	x			
.573(a)	External Corrosion Control - Protected Pipelines	x			
.573(b)	External Corrosion Control - Unprotected Pipelines			x	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	x			
.579(a)	Corrosive effect investigation	x			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment			x	
.579(c)	Inspection of Removed Pipe for Internal Corrosion			x	
.589	Cathodic Protection (Maps showing anode location, test stations, CP systems, etc)	x			

Comments *(If any of the above is Unsatisfactory, please indicate why):*
.571: Operator is primarily using the 850 mv cathodic protection criterion but is also using the 100 mv polarization criterion at several test stations. Where the 100 mv criterion is being used the Operator has established "target" pipe-to-soil potential values that are being measured with current applied ("on" potentials). The "target" pipe-to-soil potentials are based on previously conducted tests that have determined "instant off" potential values and depolarized potential values. NACE TM0497-97 permits the use of "on" potentials for monitoring after 100 mv or more of polarization has been established, provided no significant changes to the system have occurred. The Operator was advised that if and when the line is put back into service it would be advisable to conduct "instant off" measurements to assure that the established target potentials are still valid.

.442: Year 2003 The Pipeline Group held public awareness meetings at the following locations:
Benton, AR 6/19/03
Glenwood, AR 7/22/03
Texarkana, AR 7/24/03

.52, .54 and .56: No accidents, incidents or SRC's since the last OPS inspection.

No construction activity since the last OPS inspection.

.404(b)(1): Pressure charts being maintained at pump stations though the line is under a nitrogen purge, about 200 psig being maintained in the system.

.428(a): Operator has been conducting semi-annual inspections of over pressure protection equipment but plans on going to an annual schedule as long as the line is out of service.

.412(b): Arkansas River crossing was inspected 6/11/02 by Buzzard Survey. Inspection report indicates some exposed pipe in the river channel and recommends inspecting again in 2004.

Aerial patrols are being done weekly.

Atmospheric Corrosion: The Operator has a large number of exposed sections of pipeline that are documented on an exposed pipe report. Many of these exposed sections are in need of remedial work. The Operator is going to implement a new "atmospheric corrosion report" to comply with the requirements of 195.583.

- Receiver Trap north side of Arkansas River: Tape coating at soil/air interface was found to be in poor condition with some surface rust showing,
- MP 392.2 Exposed Creek Crossing: Aluminum Epoxy Coating is deteriorated and in need of complete recoating. No pitting could be seen but general surface rust was present.
- Conway Station Heated Strainer: Insulation in poor condition, Operator has plans to remove insulation and recoat this work has been done for similar strainer at Foreman Station.

Oil Pollution Act High Impact Inspection (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number _______ Approval Date___________ [See Guidance OPA-1]			x
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]			

OPA Inspection Guidance

<u>OPA-1</u> - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS 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, OPS HQ always puts the sequence number in every plan-related letter to operators.

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

<u>OPA-2</u> - 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.

<u>OPA-3</u> - 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.

<u>OPA-4</u> - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS 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 OPS 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.

<u>OPA-5</u> - 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.

INSPECTION SUMMARY

The pipeline has been out of service and under a nitrogen purge since December, 2002. The line is being maintained at about 200 psig, which is being monitored through pressure recorders at the pump stations. The status of the line should be verified prior to the next OPS inspection.

No accidents, incidents, SRC's or construction activity since the last OPS inspection, December 2001.

No problems were found with O&M records, the line and ROW are being maintained as required.

The Operator should conduct "instant off" pipe-to-soil potential measurements prior to putting the line back in service, at test stations where the 100 mv polarized potential criterion is being used.

Arkansas River crossing inspection reports need to be checked at the next OPS inspection to determine if a 2004 inspection was conducted and to determine if the exposure at the river channel has gotten worse and is need of remedial work.

The Operator has a large number of pipe exposures which will need to be inspected for atmospheric corrosion by the next OPS inspection in order to comply with 195.583. Many of these sites will need remedial work. Check condition of Receiver Trap north of Arkansas River, MP 392.2 Exposed Creek Crossing and Conway Station Heated Strainer, all should be recoated by next OPS inspection.

Attachment 1 - SCADA LIQUID WORKSHEET

Note: If the Operator has had or has been scheduled for an Integrity Management Program inspection this year,
DO NOT USE THIS WORKSHEET.

1. **Pipeline Safety Advisory Bulletin - ADB-99-03 - July 7, 1999**
• Review Bulletin with Operator.

Comments:

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. **195.402(d)(1)(iii) - Loss of communications.**
• Off-site Back-up Center
• Data transfer to redundant or off-site processors
• Battery and/or Emergency Generator
• Redundant data communications paths, automatic restoration or manual?
• Data Reduction & Archiving
• Operating practices during data communications outages

Comments: N/A Pipeline out of service.

3. **§195.404 - Pump station discharge pressure records.**
• Discharge Pressure records in SCADA or at field locations?
• Data Reduction & Archiving
• Data acquisition frequency

Comments: Line is out of service, pump station pressures are being recorded on pressure charts.

Attachment 1 - SCADA LIQUID WORKSHEET

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;
(vii) Safety devices to which §195.428 applies.
(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations
- Ensure pipeline safety parameters are current (ie: MOP, alarm set points, etc)
- Data Reduction & Archiving
- Data acquisition frequency

Comments: N/A Pipeline out of service.

5. **§195.408 - Communications.**
(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-Short Reports
- Maintaining MOP/MAOP

Comments: N/A Pipeline out of service.

6. §195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance

- Over-Short Reports
- Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments:
N/A Pipeline out of service.

7. §195.420 & .428 - Testing applicable SCADA controlled valves, safety devices, and overfill systems.

Comments:
N/A Pipeline out of service.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y:________N:_________

Comments: N/A Pipeline out of service and under nitrogen purge.

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y:________N:________

Comments: N/A Pipeline out of service and under nitrogen purge.

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y:_______N:______

Comments: N/A Pipeline out of service and under nitrogen purge.

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y:______N:_____

Comments: N/A Pipeline out of service and under nitrogen purge.

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5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y:________ N:__________

Comments: N/A Pipeline out of service and under nitrogen purge.

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y:________ N:________

Comments: N/A Pipeline out of service and under nitrogen purge.

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y:______ N:________

Comments: N/A Pipeline out of service and under nitrogen purge.

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y:________ N:_______

Comments: N/A Pipeline out of service and under nitrogen purge.

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9. Does the operator track internal corrosion and take corrective action to prevent recurrence?
Y:________N:_______

Comments: N/A Pipeline out of service and under nitrogen purge.

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
______ Gas and Fluid analysis
______ Rates of pipeline corrosion as determined by coupons
______ Solids removed from the system
______ Analysis of inhibitor samples from the pipeline
______ Magnetic and electronic device (pigs)
______ Other

Comments: N/A Pipeline out of service and under nitrogen purge.

11. Is the inhibitor compatible with the product being transported? Y:________N:_______

Comments: N/A Pipeline out of service and under nitrogen purge.