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

820 Bear Tavern Road. Suite 306
West Trenton, N.J. 08628

NOTICE OF PROBABLE VIOLATION
NOTICE OF PROBABLE CIVIL PENALTY
AND
NOTICE OF PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 26, 2009

Mr. Lawrence Shelton
Vice President, Field Operations
Buckeye Partners, L.P.
5 TEK Park
9999 Hamilton Blvd
Breinigsville, PA 18031

CPF 1-2009-5002

Dear Mr. Shelton:

From May to December 2008, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the New York Public Service Commission pursuant to Chapter 601 of 49 United States Code inspected Buckeye Partners, L.P. (BPL)'s procedures and records for Operations and Maintenance, Operator Qualification, and Integrity Management at BPL's Headquarters office, and field inspection of pipeline facilities in the states of Pennsylvania, Ohio, Illinois, Michigan and Colorado.

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

1. § 195.401 General requirements.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition....

The inspection team discovered that 1) a block of wood was being used as support for a control valve in the Greensburg Station; 2) a support device at the tank farm in Toledo, Ohio was installed on the 16-inch manifold where pipe modifications had been made, but no associated concrete foundation was present under the pipe support; 3) at the Malvern Station, the pipeline was found to be in contact with a cutoff section of pipe near a line tank; and 4) at the Greensburg Station, the pipeline was found to be in non-intentional contact with a concrete block at the pig receiver. Buckeye failed to correct these adverse conditions within a reasonable time, as required by the regulation.

2. §195.402 Procedural manual for operations, maintenance, and emergencies.

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

At the time of the inspection, BPL could not demonstrate that required reviews of the operations, maintenance, and emergency manuals had been performed once per calendar year at intervals not exceeding 15 months.

3. §195.402 Procedural manual for operations, maintenance, and emergencies.

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

BPL failed to follow its O&M procedures which require a root cause analysis for accident reports. The PHMSA inspection team identified 25 accident reports that did not include a root cause analysis as required by company procedures.

4. **§195.403 Emergency Response Training.**

(a) Each operator shall establish and conduct a continuing training program to instruct emergency response personnel...

(b) At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:

(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and

(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective....

At the time of the inspection, BPL could not demonstrate that the company had reviewed the performance of personnel during emergencies at the required intervals.

5. **§195.412 Inspection of rights-of-way and crossing under navigable waters.**

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

BPL uses aerial patrols to inspect surface conditions. However, at the time of the inspection, excessive vegetation and overgrowth was found at 1) the Perryville Station, PA;
2) near stations 814+59, 1290+71 and 128+60 on the Laurel pipeline, in PA; and 3) and near Strawberry Mansion (station 1049+72) in PA. Therefore, detrimental conditions or leaks could not be adequately observed by aerial patrols due to the overgrowth.

6. **§ 195.557 Which pipelines must have coating for external corrosion control?**

Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is—

(a) Constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c), not including the movement of pipe covered by §195.424....

At the time of the inspection, soil-to-air interface on the 301 Line pump discharge pipe and two sample lines at the BPL Toledo Station in Ohio were not coated as required by the regulation.

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

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months.**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months.**

BPL records indicated that atmospheric corrosion control inspection for the above ground piping of Mantua Station exceeded the required intervals. Inspections were conducted on 5/4/2004 and 1/29/2008 which exceeded the 39 months interval.

8. § 195.573 What must I do to monitor external corrosion control?

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier **Reverse current switch.** **Diode.** **Interference bond whose failure Would jeopardize structural protection.**	**At least six times each calendar year, but with intervals not exceeding 2 1/2 months.**
Other interference bond	**At least once each calendar year, but with intervals not exceeding 15 months.**

BPL failed to check multiple rectifiers at the required frequencies to ensure proper performance. Specifically, a review of the BPL Rectifier Output History Report for 1/1/2006 to 5/1/2008 indicated that inspection intervals for the Harristown Shell system exceeded the 2-1/2 month maximum interval between May and September 2006) by approximately 1-1/2 months for three rectifiers.

A review of the Rectifier Output History Report for 1/1/2006 to 5/1/2008 demonstrates that rectifiers (No.1, No.2, No.3, PM-0.01) in the BPL Trans PA, Malvern Station Tank farm, Paulsboro Deep Well, and Chester Park were not checked at least six times in the 2006 - 2007 calendar period.

A review of the Rectifier Output History Report for 1/1/2006 to 5/1/2008 indicated that inspections for the Booth Rectifier LP-07 for Tank #15 exceeded the maximum 2-1/2 month interval between 03/05/2006 to 05/26/2006.

A review of the Rectifier Output History Report for 1/1/2006 to 5/1/2008 indicated that BPL did not inspect the rectifier at Booth LP-08 STA40009 BH724SK between 9/5/2006 and 1/12/2007, exceeding the maximum 2 ½ month interval.

9. § 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP 0169 (incorporated by reference, *see* §195.3).

BPL could not demonstrate that the cathodic protection for the facilities at the Philadelphia, PA airport complied with the applicable criteria. According to BPL's representative, the company does not know if there are adequate levels of cathodic protection for BPL facilities at the Philadelphia, PA Airport apparently due to access limitations. BPL has not taken any pipe-to-soil readings since October 2006.

10. § 195.573 What must I do to monitor external corrosion control?

(e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

BPL did not correct identified corrosion control deficiencies within a reasonable time period, as required by the regulation. A review of Test Point Survey Reports, for 920 NGL, identified inadequate levels of cathodic protection. Specifically, the CP survey at the test point location I-70 XING South, for 920 NGL, indicated inadequate levels of CP in the 2006 and 2007 annual surveys but were not corrected until February 2008.

11. § 195.573 What must I do to monitor external corrosion control?

(e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

The inspection team's review of the BPL work orders demonstrated that several locations with low CP readings were not corrected by the next inspection cycle. Under §195.401(b), BPL was required to correct the deficiency within a reasonable time. Although BPL had an obligation to correct the deficiency within the time period set in the regulation, the company records reflected that the work at the twelve locations was scheduled to start between years 2005-2007 and yet had not been completed by the time the PHMSA inspection occurred.

12. § 195.438 Smoking or open flames.

Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

BPL did not prohibit smoking and open flames in the designated areas. Buckeye could have posted signs identifying potential hazards and prohibiting smoking and open flames. During the field inspection, it was noted that the National Fire Protection Association (NFPA) hazardous diamond placards, indicating that the tanks contain flammable liquid and vapors, were not posted on tanks at the Chelsea or the Booth facilities in PA. It was also noted that "No Smoking" signs were not posted at the entrance to tank dikes at Booth Station. Although some of the Booth area tanks were marked as a "No Smoking" area, others were not appropriately marked.

13. §195.402 Procedural manual for operations, maintenance, and emergencies.
(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted....

On March 22, 2005, on BPL's 209 Line in Wayne, Michigan, personnel failed to follow Buckeye's repair procedures for dents. Per Buckeye's procedure MA E-08 and associated Exhibit H, all "sharp" dents shall be repaired using a sleeve. However, the dent at Sta. 913+96 was not repaired using a sleeve.

On June 1, 2005, BPL's personnel failed to repair a wrinkle bend in conformance with Buckeye's repair procedures. At the listed MOP of 1233 psig, the wrinkle bend would require repair per Procedure MA E-08, MA E-08 Exhibit I. Instead, Buckeye's management decided that since the line does not normally operate above 900 psig, no repair was necessary. However, Buckeye did not re-establish the MOP of the line to the lower 900 psig. BPL did not initiate an engineering evaluation of the wrinkle bend until 2008, after the issue was brought to BPL's attention during the PHMSA inspection.

14. §195.452 (j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

At the time of inspection, BPL could not demonstrate that periodic evaluations of the pipeline integrity program were performed as required by the integrity management regulations. The BPL Integrity Management Plan manages approximately 3,558 miles of HCA piping.

15. §195.452(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1................................	**December 31, 2001.**
Category 2................................	**November 18, 2002.**
Category 3................................	**Date the pipeline begins operation.**

At the time of inspection, BPL failed to identify in its Baseline Assessment Plan idle pipelines intersecting with HCAs. BPL's identification of facilities that could affect HCAs was to be completed by Dec. 31, 2001, per the regulation. Identification of idle pipelines is necessary to consider risks which could affect an HCA.

16. §195.452(b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date

Category 1................................ December 31, 2001.
Category 2................................ November 18, 2002.
Category 3................................ Date the pipeline begins operation.

Buckeye did not identify all facilities affecting HCAs. Buckeye did not consider the contribution of tank volumes from tank farms to overland spread, nor was an overland spread analysis performed at facilities greater than ¼ mile from HCAs. After identification of this issue by the PHMSA inspection team in 2008, Buckeye subsequently identified 6 additional facilities with the potential to affect HCAs using overland spread analysis.

17. **§195.452(f) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:**
(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

Buckeye failed to include a process to identify potential preventive and mitigative actions in its written integrity management program. Buckeye operates 5,576 miles of pipe of which 3,558 miles could affect an HCA. Therefore, it is particularly important for Buckeye to consider and identify preventive and mitigative measures to provide further protection to these areas.

18. **§195.452(i) What preventive and mitigative measures must an operator take to protect the high consequence area?**
(2) *Risk analysis criteria*. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:
(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
(ii) Elevation profile;
(iii) Characteristics of the product transported;
(iv) Amount of product that could be released;
(v) Possibility of a spillage in a farm field following the drain tile into a waterway;
(vi) Ditches along side a roadway the pipeline crosses;
(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure....

Buckeye failed to evaluate the likelihood of a pipeline release occurring and how such an event could affect the HCAs in order to determine the need for additional preventive and mitigative measures. This determination must consider all relevant risk factors including but not limited to the criteria listed in **§195.452(i)(2)(i)-(viii).** Buckeye failed to assess these risk factors.

19. §195.452(i) What preventive and mitigative measures must an operator take to protect the high consequence area?
(4) Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors–the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

At the time of inspection, Buckeye had not performed EFRD evaluations since 2005. BPL's Integrity Management Plan, Section 15, issued 12/2005, requires annual review of pipelines scheduled for integrity assessment during that year to determine whether impact to an HCA can be mitigated by adding an EFRD. Buckeye also did not have a technical justification explaining why the EFRDs recommended in 2002 had not been installed.

20. §195.452 (f) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:
(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section)

Buckeye did not change its integrity management program to reflect relevant operating experience. In May 2005, Buckeye's Risk Management Team determined that the risk analysis program did not provide the necessary insight for the risks associated with the analyzed pipeline segments. However, actions to improve the risk analysis model were not initiated until 2008.

21. § 195.561 When must I inspect pipe coating used for external corrosion control?