WARNING LETTER

VIA UPS – TRACKING # 1Z WR2 588 02 9465 4207

April 29, 2011

Mr. James Bowzer
Vice President, North America Production Operations
Marathon Oil Company
5555 San Felipe Rd.
Houston, TX 77056

CPF 5-2011-2001W

Dear Mr. Bowzer:

On September 1-2, 2010, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected Marathon Oil Company's Spark/Spur natural gas transmission pipeline in Kenai, Alaska.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. **§192.465 External corrosion control: Monitoring**
   (b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.

The operator failed to provide evidence that all cathodic protection rectifiers were inspected within intervals not exceeding 2 ½ months. Records indicate that the rectifiers on the Spark Platform were inspected on June 19, 2009 and December 17, 2009, and do not indicate rectifier inspections were performed between these two dates.

2. §192.479 Atmospheric corrosion control: General
(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
(b) Coating material must be suitable for the prevention of atmospheric corrosion.

PHMSA personnel observed numerous soil-to-air interfaces on the 3-inch diameter pipeline section that were not coated.

3. §192.481 Atmospheric corrosion control: Monitoring
(a) Each operator 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:	**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**

The operator failed to provide evidence that all atmospherically exposed portions of the 3-inch diameter pipeline were inspected for atmospheric corrosion. Evidence provided indicates atmospheric corrosion inspections were conducted at locations identified as 1+00, 1+10, and 2+00. No documentation was presented to show that atmospheric corrosion inspections were conducted between the locations identified as 1+10 and 2+00, where there are several atmospherically exposed portions of the pipeline.

4. §192.619 Maximum allowable operating pressure: Steel or plastic pipelines
(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:
(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:
(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

<table>
<tr><th rowspan="2">Class location</th><th colspan="3">Factors (see Note), segment</th></tr>
<tr><th>Installed Before Nov. 12,1970</th><th>Installed After Nov. 11, 1970</th><th>Converted under §192.14</th></tr>
<tr><td>1</td><td>1.1</td><td>1.1</td><td>1.25</td></tr>
<tr><td>2</td><td>1.25</td><td>1.25</td><td>1.25</td></tr>
<tr><td>3</td><td>1.4</td><td>1.5</td><td>1.5</td></tr>
<tr><td>4</td><td>1.4</td><td>1.5</td><td>1.5</td></tr>
<tr><td colspan="4">Note: For offshore segments installed, or updated, or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated, or converted after July 31, 1977 that are located on an offshore platform or on a platform in inland navigable waters (including a pipe riser), the factor is 1.5</td></tr>
</table>

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

<table>
<tr><th>Pipeline segment</th><th>Pressure date</th><th>Test date</th></tr>
<tr><td>-Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.</td><td rowspan="2">March 15, 2006, or date line becomes subject to this part, whichever is later.</td><td rowspan="2">5 years preceding applicable date in second column.</td></tr>
<tr><td>-Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.</td></tr>
<tr><td>Offshore gathering lines.</td><td>July 1, 1976</td><td>July 1, 1971.</td></tr>
<tr><td>All other pipelines.</td><td>July 1, 1970</td><td>July 1, 1965.</td></tr>
</table>

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.
(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.
(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in § 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under § 192.620(a)

This pipeline has been operated under a MAOP of 1030 psig. The operator failed to provide evidence that MAOP for the 3-inch diameter pipeline section was determined in accordance with §192.619. The MAOP determination for the 3-inch pipeline was based solely on the maximum pressure experienced by the pipeline during a 1 ¼ year period, from October 2007 to January 2009.

5. §192.743 Pressure limiting and regulating stations: Capacity of relief devices
(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations

The operator failed to provide evidence that the capacity of the relief devices had been determined at intervals not exceeding 15 months, but at least once each calendar year. PHMSA issued a Warning Letter to Marathon Pipe Line, LLC regarding this same issue (CPF 5-2010-0001W, Item 6, dated January 4, 2010). In response to the warning letter, Marathon Pipe Line, LLC initiated an Alaska Gas Pressure Control Oversight Transition Plan to remedy the issue. Marathon Oil Company has indicated that the Spark/Spur natural gas transmission pipeline's pressure relief system is included in the transition plan and its capacity will be determined at intervals in accordance with §192.743.

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

No reply to this letter is required. If you choose to reply, in your correspondence please send all documents to our office at 188 W. Northern Lights Blvd., Suite 520, Anchorage, AK 99503 and refer to **CPF 2011-2001W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Dennis Hinnah
Deputy Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 T. Johnson (#130350)