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May 18, 2011

05-24-11P12:04-ARNV

Mr. Dennis Hinnah  
Deputy Director, Western Region  
U.S. Department of Transportation  
Pipeline and Hazardous Materials Safety Administration  
188 W. Northern Lights Boulevard, Suite 520  
Anchorage, AK 99503

Re: Warning Letter CPF 2011-2001W

Dear Mr. Hinnah:

The attached document is Marathon Oil Company's (MOC) response to the US Department of Transportation's Warning Letter, dated April 29, 2011. The Warning Letter was issued following the Pipeline and Hazardous Materials Safety Administration's (PHMSA) 2009 inspection of MOC's gas pipeline from Granite Point on the West Side of the Cook Inlet in the Kenai Peninsula region of Alaska to our Spark Platform in the Cook Inlet (the "Inspection").

While MOC has policies and procedures in place to achieve our objectives of protection of the public, our employees, and the environment, we constantly strive for continuous improvement. MOC appreciates the professionalism shown by your staff during this inspection, through which we and PHMSA's Western Region have developed a positive working relationship. We hope to further this relationship with ongoing dialogue in pursuit of our shared goal of safety.

MOC requests that if CPF 2011-2001W is made available on the PHMSA website, this reply is posted as well.

Please contact me if you would like to discuss this matter further.

Sincerely,

A handwritten signature in black ink, appearing to read 'Carri A. Lockhart', is written over a printed name. The signature is stylized and somewhat illegible due to the cursive nature of the handwriting.

Carri A. Lockhart

**Probable Violation 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.*

**Finding**

The operator failed to provide evidence that all cathodic protection rectifiers were inspected within intervals not exceeding 2 ½ months. Records indicate that 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.

**MOC Response**

A project to install Remote Monitoring Units (RMU) for the rectifiers on the platform was underway at the time of the inspection. That project is now completed, and the RMUs automatically transmit electronic rectifier performance data to our database on a monthly basis, which exceeds the minimum intervals required under §192.465.

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**Probable Violation 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.*

**Finding**

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

**MOC Response**

The 3-inch pipeline observed by the inspector is scheduled for replacement in its entirety during the 2011 construction season. This work was approved prior to the inspection and the projected completion date for this project is mid-August of this year. Buried portions of the new steel pipe will have an external protective coating which, in conjunction with a cathodic protection system, will help protect the line from external corrosion. The limited portions of the new line that will be above grade and exposed to the atmosphere—its origin and termination—will be suitably coated to prevent atmospheric corrosion.

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**Probable Violation 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:*

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

## **Finding**

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.

## **MOC Response**

During right-of-way clearing prior to this matter's subject PHMSA inspection, portions of the 3-inch pipeline that had previously been covered by dense vegetation overgrowth became apparent, and these portions were noted by the inspector. The most recent atmospheric corrosion inspections at locations 1+00, 1+10, and 2+00 were done as representative samples of the pipeline. Were this pipeline to not be replaced as referenced under our response to Probable Violation 2 (above), the exposed portions would have been cleaned and recoated, and their locations would have been added to our list for future atmospheric corrosion monitoring inspections.

## **Probable Violation 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 12 ¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).*

*(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:*

Class location	Factors <sup>1</sup> , segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.4	1.5
4	1.4	1.4	1.5

<sup>1</sup>For offshore segments installed, uprated 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.

*(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:*

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

(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 over-pressure 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).

### **Finding**

The pipeline has been operated under an MAOP of 1,030 psig. The operator failed to provide evidence that the 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 1¼ year period from October 2007 to January 2009.

### **MOC Response**

In July 2009, the 3-inch pipeline in question was determined by MOC to be a transmission pipeline subject to Part 192. This was a result of the PHMSA interpretation requested by MOC in September 2008. Previously, it was considered to be an unregulated fuel line. Among the tasks MOC needed to address to comply with Part 192 was that requiring the establishment of an MAOP. The company recognized that the regulations allowed the use of historic operating pressures as a means of establishing MAOP for pipelines that were in service prior to being regulated under Part 192. Accordingly, the company relied on the highest operating pressure for which it had records. That pressure was 1,030 psig, as recorded in June 2008.

MOC acknowledges that it did not accurately apply the use of historic operating pressures to establish this line's MAOP. However, as already mentioned in this response, this line is being replaced in the next several weeks and will be strength tested as required under *Subpart J—Test Requirements* before being placed into service. The new line's MAOP will be established through application of the successful strength test and related paragraphs of §192.619.

### **Probable Violation 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.*

**Finding**

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.

**MOC Response**

The PHMSA finding above for this item states that Marathon Pipe Line LLC's Alaska Gas Pressure Control Oversight Transition Plan includes the pressure relief system for the Spark /Spur system which is incorrect. This system's capacity requirements are being determined under MOC's own pressure analysis project, which is scheduled for completion by November 30, 2011.