bp

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SENT VIA FED-EX

March 22, 2013

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Mr. David Barrett
Director, Central Region
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
901 Locust Street, Suite 462
Kansas City, MO 64106

Re: CPF 3-2013-5004

Dear Mr. Barrett:

BP Pipelines (North America) Inc. (BP) is responding to the Notice of Probable Violation (NOPV), Proposed Civil Penalty, and Proposed Compliance Order (PCO) received in our offices on February 20, 2013, regarding the Integrated Inspection conducted during August 2, 2010 through December 10, 2010 with the inspection close on January 19, 2011. Subject to the clarifications and explanations in this response and any reply from the Pipeline and Hazardous Materials Safety Administration (PHMSA), BP does not contest the proposed civil penalty. However, BP is contesting certain items (described below) in the NOPV and the PCO. BP believes that certain requirements in the PCO could be interpreted too broadly or are misdirected. Therefore, BP proposes specific modifications to the PCO to resolve BP's concerns. Finally, BP reserves the right to a hearing for items, if any, which PHMSA deems unresolved by this response.

BP proposes the following changes to the PCO and NOPV:

PCO Item 1 and NOPV Finding 3: BP believes that PCO Item 1 should be modified to indicate that it pertains to procedures relating to close interval survey (CIS) findings. Since the time of the Integrated Inspection, BP has revised its procedures, and BP believes that its revised procedures now meet the requirements of PCO Item 1. Attachment 1 contains further information on these items as well as proposed modifications to the language in PCO Item 1.

PCO Item 2 and NOPV Finding 4: BP believes that these items should be withdrawn. PCO Item 2 seeks changes to BP's Remedial Action Procedure "to ensure that all future assessments are properly evaluated, appropriate actions are taken in a timely fashion, and all activities are clearly documented". However, BP's USPL Site Technical Practice (STP) 32-200 – which was in effect at the time of the Integrated Inspection – already addresses each of the points raised by PHMSA. Further, the specific issue raised in NOPV Finding 4 is not accurate. Attachment 1 contains further information on these items.

PCO Item 4 and NOPV Finding 5.b: BP believes that these items should be withdrawn. BP uses a PHMSA-sponsored and endorsed process to determine seam reassessment interval for pipelines that are susceptible to seam failure (OPS TT05 - Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation Report). Pursuant to this guidance, an operator may perform seam reassessments at intervals that exceed five (5) years, in appropriate circumstances. Attachment 1 contains further information on these items.

PCO Item 5: BP believes that PCO Item 5 should be modified to indicate that the requirements apply to pre-1970 ERW and Lap Welded longitudinal seam pipe. Attachment 1 contains proposed modifications to the language in PCO Item 5.

PCO Item 7: BP believes that PCO Item 7 should be modified to provide additional time within which to complete all required re-evaluations. Attachment 1 contains proposed modifications to the language in PCO Item 7.

Attachment 2 provides additional information regarding NOPV Findings 1, 2, 5.a, 5.c, 5.d., and 6. BP believes that these findings are the result, at least in part, of certain misunderstandings during the Integrated Inspection. Nevertheless, BP is not proposing any changes to the PCO. BP offers this information only for context and clarification about BP's work processes.

BP looks forward to working with PHMSA to resolve these items.

If you have any questions, please feel free to contact Dave Barnes at (630) 536-3419.

Sincerely,

S. Pankhurst

Steve Pankhurst.
President
BP Pipelines (North America) Inc.

Attachments

cc: file copy

Attachment 1

This Attachment provides proposed changes to PCO Items 1, 5 and 7, and it provides additional information regarding PCO Items 2, and 4, which BP believes may have been misunderstood during the Integrated Inspection process. Where appropriate, the relevant findings are restated below, along with BP's response that includes additional information.

PCO Item 1

BP proposes the following changes to the first sentence of PCO Item 1 (additions are shown in **bold**):

> In regard to Item Number 3 of the Notice pertaining to prompt action to address all anomalous conditions, BP shall review and revise all procedures **related to Close Interval Survey findings** that allow timing of action longer than one year, unless a detailed justification is provided documenting the rationale for a longer interval.

BP's rationale for this change is that the originally drafted language is too broad and could be construed to apply to all BP procedures. The specific concern cited in NOPV Finding 3 relates only to CIS findings, so the corresponding PCO Item should address CIS findings[1].

Since the Integrated Inspection, BP has modified its CIS procedure to clarify "prompt action to address all anomalous conditions". BP believes that the modified CIS procedure meets the requirements of PCO Item 1.

Additional Information on NOPV Finding 3

NOPV Finding 3 states:

> *BP did not take prompt action to address all anomalous conditions it discovered through information analysis. As part of its integrity management program, BP identified close interval surveys (CIS) to be conducted for certain HCAs including Black Lake Station to Toro Station, Toro Station to Hardin Station, and Hardin Station to Mt. Belvieu, Texas. The CIS conducted from Hardin Station to Mt. Belvieu, Texas, identified several locations where the IR-Off-readings were outside of established criteria and the findings were discovered during the 2005 surveys. BP procedures did not require investigations of those CIS findings until December 31, 2010. PHMSA's review of the data on August 28, 2010, showed the operator had not completed the investigations. The rule requires that an operator promptly "address all anomalous conditions the operator discovers through the integrity assessment or information*

[1] Many BP procedures include actions that extend beyond a year and conform with PHMSA guidelines. The timing of these activities is reasonable and appropriate in those circumstances.

analysis." Exceeding four years to address findings resulting from information analysis is not prompt action.

BP Response:

The BP procedure for close interval survey (CIS) findings has been revised and clarified and is located in BP's OMER Book 1, Corrosion Control Procedure P-195.551, Appendix B. Areas of immediate concern are addressed in accordance with Section K.5 of this same procedure.

The information analysis process referenced in NOPV Finding 3 is not intended to drive specific actions on all findings that are identified during a CIS. Rather, BP's policies and procedures require that CIS results be evaluated to identify areas of concern that require immediate action, and those areas are addressed as required. The CIS data constitute one of several data inputs that BP evaluates in its information analysis process to determine when the next scheduled pipeline reassessment should occur. So, although it is true that some findings identified in the 2005 CIS had not been fully addressed by August 2010, this was because (i) the areas of concern were not "immediate concerns", and (ii) BP's analysis of all relevant data (including, for example, past and current CIS results and past and current in-line inspection results) indicated that these areas of concern would "not reduce [the] pipeline's integrity."

Areas requiring mitigation are identified and action plans put in place to correct identified deficiencies. In most situations, action is completed within a year. In certain circumstances, however, mitigation activities could extend beyond one year, for activities such as re-coating a significant length of pipeline, installing a new rectifier, or replacing significant lengths of pipeline.

BP believes that its procedural clarifications address NOPV Finding 3 regarding the importance of taking prompt action to address areas of immediate concern.

PCO Item 2

BP believes this item should be withdrawn. PCO Item 2 seeks changes to BP's Remedial Action Procedure "to ensure that all future assessments are properly evaluated, appropriate actions are taken in a timely fashion, and all activities are clearly documented". However, BP's USPL Site Technical Practice (STP) 32-200 – which was in effect at the time of the Integrated Inspection – already addresses each of the points described in PCO Item 2. Further, the specific issue raised in NOPV Finding 4 is not accurate.

Attachment 1

Additional Information for NOPV Finding 4

NOPV Finding 4 states:

> *BP did not evaluate a condition identified by an integrity assessment that could impair the integrity of the pipeline. BP conducted an inline inspection (ILI) of its Endymion Pipeline in January of2010. By June of2010, the operator had received the report from the ILI vendor and determined that the run was unacceptable. On June 30, 2010, the operator then submitted to PHMSA a notification to extend the assessment interval due to the inadequate tool run, stating a subsequent MFL tool would be re-run later in 2010. On August 16, 2010, the operator attempted to retract its notification of June 30, 2011, indicating the tool run was of acceptable quality. During the PHMSA inspection, the results of the run were reviewed and BP was asked about the internal corrosion indication reported by the January 2010 ILI run. The indication measured 39.3 inches in an axial direction and 26.9 inches in a circumferential direction and was reported to be 11% in depth, which is characteristic of an "anomaly over a large area" that should be evaluated. The operator was asked about its follow-up actions regarding the indication and BP formally responded on January 7, 2011. There appears to have been no formal process for reviewing and addressing this anomaly or actions to mitigate the potential for internal corrosion. The operator's IM procedure "Remedial Actions Procedure #P-195.452.f4" requires in section "1.3 Remedial Actions Tracking and Maintenance" that "each HCA condition that is discovered either through ILI assessment or the normal course of pipeline operations to assure timely remedial action implementation." At the time of PHMSA's inspection, BP could not document any actions were taken to address the indication of potential internal corrosion over a large area. BP eventually inspected the pipe at the location to verify this condition did not require repair; although not in a timely manner.*

BP Response:

BP contests NOPV Finding 4. Given the shallow nature of the pipe anomaly, this feature does not meet the "other" condition criteria listed under 49 CFR § 195.452(h)(4)(iv). BP's analysis did not indicate that this feature was a condition that could impair pipeline integrity. The feature in question was estimated to be between 2% and 11% in depth, with the majority of the feature depths at less than 2%. A feature of this depth does not meet any regulatory or BP timed conditions or other criteria.

Attachment 1

The internal feature in question was reported by the ILI tool to be estimated between 2% and 11% in depth, with the majority of the feature depths at less than 2%. As this feature was accessible, BP further investigated this site through direct-measurement non-destructive examination (NDE) in November 2010. The feature average depth was measured to be approximately 1/100 of an inch in 0.661" wall pipe, with a maximum depth measurement of 0.053" or 8% of nominal wall. This feature has been investigated again with NDE techniques in 2013 and there appears to be no change detected since 2010. It is noteworthy that pipe specification tolerance for 30" DSAW 0.661" wall pipe per API 5L is 0.060" or about 9% of nominal wall, so the actual measured maximum depth was within the tolerance of newly manufactured pipe. A feature of this depth does not meet any regulatory or BP timed conditions or other criteria. Further, according to Modified B31G, corrosion less than 20% is allowed for an infinite length.

Section VII of Appendix C of 49 CFR Part 195 includes several factors that provide additional guidance for when an operator should schedule a specific condition for evaluation and remediation. None of those factors applied to this situation:

1. There was no change that could be noted from a prior assessment because the baseline inspection of this particular pipeline section was a hydrotest (so no comparison to past ILI). There was, however, further analysis on other internal features noted from the prior ILI run and the conclusion was that there were no changes on internal features from run-to-run;
2. There was no mechanical damage;
3. The feature was not abrupt in nature;
4. The shallow nature of this feature did not cause concern regarding its orientation and did not represent a concern to pipeline integrity;
5. The average and maximum depth and area dimensions of this feature obtained through direct NDE measurement was quite small and did not represent an anomaly over a large area;
6. The feature was not located in or near a casing, a pipeline crossing, or an area with suspect cathodic protection.

In short, in the absence of some type of triggering factor (such as the factors described in Section VII of Appendix C of 49 CFR Part 195), it simply is not reasonable to expect operators to investigate conditions with dimensions that fall within pipe specification tolerance.

BP believes that there were no deficiencies in BP's procedures regarding proper evaluation and action, because this feature did not meet any regulatory or BP-specific criteria that required follow-up action. BP believes PCO Item 2 is unnecessary because there are no procedural deficiencies related to evaluating pipeline assessments.

Attachment 1

PCO Item 4

BP believes that this item should be withdrawn. BP uses a PHMSA-sponsored and endorsed process to determine seam reassessment interval for pipelines that are susceptible to seam failure (OPS TT05 - Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation Report). Pursuant to this guidance, an operator may perform seam reassessments at intervals that exceed five (5) years, in appropriate circumstances.

Additional information for NOPV Finding 5b

NOPV Finding 5.b). states:

> *b) BP could not demonstrate that adequate continual assessments were identified and performed because BP's procedure did not sufficiently address the reassessments of Low Frequency ERW and Lap Welded longitudinal seam pipe and ensure assessments are completed. Where pipelines are identified as susceptible to seam failure for these types of pipe, BP allowed re-assessment intervals longer than five years.*

BP Response:

BP contests NOPV Finding 5.b). BP's procedure does properly address the reassessments of Low Frequency ERW and Lap Welded longitudinal seam pipe. BP's procedure is based on, and consistent with, a PHMSA-sponsored and endorsed Technical Report, OPS TT05 - Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation Report. BP's procedure utilizes this Report in application of seam susceptibility determinations as well as establishing seam reassessment intervals. BP utilizes a process specifically outlined in this Report to re-evaluate seam susceptibility on an annual basis.

For those segments that are determined to be susceptible to seam failure, the seam reassessment interval is based on the guidance provided in this Report, which states that seam reassessment is performed at or before the time that half the predicted time to failure will be reached. BP's procedures are consistent with the referenced Report and reassessments for the specific threat of seam failure, when utilizing this annual evaluation process and reassessment interval model, meet the requirements of integrity management for pipe determined to be susceptible to seam failure. Since BP's procedure is based on PHMSA guidance to industry, BP believes that PCO Item 4 is not needed.

PCO Item 5

BP proposes the following changes to the first sentence of PCO Item 5 (additions are shown in **bold**):

Attachment 1

> In regard to Item Number 5 of the Notice pertaining to continual process of evaluation and assessment to maintain pipeline integrity, BP shall revise its procedures to assess and mitigate against seam threats which are also susceptible to external corrosion **for pre-1970 ERW and Lap Welded longitudinal seam pipe**.

BP's rationale for this change is that the risks addressed by PCO Item 5 and by NOPV Finding 5 are associated with known concerns about specific types of pipe – pre-1970 ERW and Lap Welded longitudinal seam pipe.

PCO Item 7

BP proposes the following changes to the third sentence of PCO Item 5 (additions are shown in **bold;** deletions are shown in ~~strikeout~~):

> BP must complete the requirements outlined within **365** ~~150~~ days of receipt of the Final Order and submit the plan and results of the re-evaluation per item #9 of this Compliance Order.

BP's rationale for this change is that 150 days is not sufficient time to complete all of the requirements that are outlined in PCO Item 7.

Attachment 2

This Attachment provides additional information regarding NOPV Findings 1, 2, 5.a), 5.c), 5.d), and 6. BP believes these findings may have been the result of misunderstandings during the Integrated Inspection process. BP submits the following information in order to provide an accurate and complete inspection record for the benefit of both PHMSA and BP.

The findings are restated below with BP's response.

NOPV Finding 1

> *BP did not inspect each mainline valve at least twice each calendar year to determine they were functioning properly.*

BP Response:

BP is not contesting this Finding, but offers the following additional information for consideration.

NOPV Finding 1 states that BP failed to inspect each mainline valve at least twice per year; the finding cites 9 mainlines valves that were not inspected. After further reviewing its records, BP has determined that 7 of the 9 valves were properly inspected: 2 of the 3 noted valves on the Sugar Creek to Council Bluffs line; the 3 noted valves located in Ohio; and 2 of the 3 noted valves located in New Jersey.

There were no missed inspections on two of the three valves on the Sugar Creek to Council Bluffs line. The valves noted (Equipment numbers 35641 and 35369) were inspected in April 2007 and October 2008, respectively. For the third valve (Equipment number 302178), one valve inspection for the second half of 2008 could not be located.

There were no missed inspections on the three valves located in Ohio. The valves noted on the West Toledo 6" pipeline (Equipment numbers 33656 and 33657) were inspected in April 2007 and in October 2009. They were not inspected between those dates because the pipeline was idled and out of service during the last half of 2007, all of 2008, and most of 2009. This pipeline was recommissioned in October 2009. These valves were inspected in April 2007, before the pipeline was idled, and again in October 2009, when the pipeline was recommissioned, consistent with BP procedures.

Also, the Toledo Refinery Dock Heavy Oil Scraper Trap valve (Equipment number 32820 (the NOVP inadvertently identified this valve as Equipment number 32830)) was inspected in the last half of 2008 and the first and second halves of 2009. The valve description changed slightly between inspections in 2008, but the valve maintained the same Equipment number. BP believes that this change in valve description inadvertently created some confusion when PHMSA was reviewing the inspection records.

There were no missed inspections on two of the three valves noted in New Jersey. Valve numbers 2704 and 2706 were both inspected in June 2009 and December 2009. For the third valve (valve number 0106), one valve inspection for the second half of 2009 was performed in January 2010, as the inspection record noted, missing the requirement of twice each calendar year.

BP requests that PHMSA review this new information and consider whether to remove the valve inspection Warning Item from the Final Order.

NOPV Finding 2

> *BP did not inspect each breakout tank for physical integrity according to API Standard 653, which requires a monthly inspection.*

<u>BP Response</u>:

BP is not contesting this Finding, but BP offers the following additional information for consideration.

NOPV Finding 2 addresses three Olympic Pipeline System breakout tanks that appeared to have been missing one or two monthly inspections during 2007. In fact, BP inspected all three of the breakout tanks cited in NOPV Finding 2 twelve times throughout the year, at regular intervals, and BP documented each inspection. However, scheduling work on an approximately thirty day cycle can cause certain calendar months to be "missed" by a couple of days, because February has less than 30 calendar days.

For all three breakout tanks, the "missing" inspections were early in the year – February and/or April. For the remainder of the year, the inspections were completed each calendar month:

DOT Utility/Surge Relief Tank - (Equipment Number 17712). The NOPV noted that this tank was not inspected in February and April 2007. Records indicate that inspections were completed on March 2, 2007 (for the February inspection), and on May 1, 2007 (for the April inspection). The dates of the twelve monthly inspections in 2007 were January 12, March 2, March 23, May 1, May 25, June 21, July 27, August 23, September 28, October 29, November 29, and December 19.

DOT Tank #202 - (Equipment Number 18990). The NOPV noted that this tank was not inspected in February 2007. Records indicate that the inspection was completed on March 1, 2007 (for the February inspection). The dates of the twelve monthly inspections in 2007 were January 2, March 1, March 30, April 17, May 31, June 27, July 25, August 29, September 24, October 29, November 29, and December 26.

DOT Renton Utility Tank #116 (Equipment Number 18405). The NOPV noted that this tank was not inspected in February 2007. Records indicate that the inspection was completed on March 2, 2007 (for the February inspection). The dates of the twelve monthly inspections in 2007 were January 15, March 2, March 16, April 27, May 25, June 29, July 19, August 28, September 17, October 17, November 7, and December 28.

BP requests that PHMSA review this information and consider whether to remove this tank inspection Warning Item from the Final Order.

NOPV Finding 5

a) *BP could not demonstrate that adequate periodic evaluations of pipeline integrity were performed because its procedure "Continual Evaluation and Assessment Procedure #P-195-452.f5" was vague and non-specific. It does not address in detail the evaluation requirements of§ 195.452(j)(2) such as risk factors in paragraph (e) which includes, but is not limited to: results of previous integrity assessments, leak history, repair history, cathodic protection history, product transported, operating stress level, existing or projected activities in the area, local environmental factors, geo-technical hazards, etc. Although the operator did perform some paragraph (g) information analysis, the actual analysis for each HCA was vague and poorly documented. Effects of preventive and mitigative actions [paragraphs (h) and (i)] were not considered.*

b) *BP could not demonstrate that adequate continual assessments were identified and performed because BP's procedure did not sufficiently address there assessments of Low Frequency ERW and Lap Welded longitudinal seam pipe and ensure assessments are completed. Where pipelines are identified as susceptible to seam failure for these types of pipe, BP allowed re-assessments intervals longer than five years.*

c) *BP could not demonstrate that their re-assessment methods and periodic evaluations were adequate to address interactive threats because BP's procedure did not address a process to assess, evaluate and mitigate seam threats which are also susceptible to external corrosion in certain pipe.*

d) *BP had pre-determined that assessment intervals could not be less than three years as described in the procedure. The re-assessment intervals should be based on contemporaneous information that is gathered through on-going periodic evaluation, assessments,* *information analysis, and other data. BP's integrity management program excluded the potential for shorter assessment intervals.*

BP Response:

BP is not contesting this Finding, but BP offers the following additional information for consideration.

Finding 5.a). Since the time of the Integrated Inspection, BP has fully implemented the Reassessment Interval Determination (RAID) process. BP believes that this change addresses Finding 5.a). Further, BP will add specificity to its Continual Evaluation and Assessment Procedure P-195.452.f.5, to address PCO Item 3.

Item 5.c). BP will revise its procedures as per PCO Item 5 to utilize metal-loss inspections in monitoring for selective seam corrosion on those segments determined to be susceptible to seam failure (i.e., segments with pre-1970 Low Frequency ERW and Lap Welded pipe). BP has not experienced a history of selective seam corrosion in BP segments that are determined to be susceptible to seam failure. BP monitors the mechanical integrity of such pipeline segments with various methods including ILI tool runs, in the ditch pipeline inspections and hydrotesting. BP has not experienced failures from selective seam corrosion on such pipelines.

Item 5.d). At the time of the inspection, the BP integrity management program did not exclude the potential for assessment intervals less than three years. BP's process specifically included an event-driven component that could establish a shorter reassessment interval. Further, as stated in Item 5.a) above, BP has now fully implemented the RAID process, which we believe further clarifies and addresses this item, because RAID states that "Under special circumstances, such as a Post Event Integrity Review, the reassessment interval (RI) could be one, two, three or four years." BP believes that PCO Item 6 is addressed with this approach.

Regarding PCO Item 7, BP will develop a plan to review the pipelines in the integrity management program after BP's procedures have been revised per the final Compliance Order.

NOPV Finding 6

BP did not complete periodic evaluations to assure pipeline integrity on all of its pipelines, including facilities. BP identified 109 facilities in HCAs and provided a spreadsheet which indicated the assessment and evaluation for each of the facilities, which included dates of inspection and the inspection types. At the time of PHMSA's inspection, BP had not documented that the FIMP/FIP (Facility Integrity Management Program/Facility Implementation

> *Plan) evaluations had been started on 47 of their facilities; consequently, there was no associated documentation to indicate that all necessary inspections, assessments, and evaluations had been completed to assure pipeline integrity.*

BP Response:

BP is not contesting this Finding, but offers the following additional information for consideration.

During a 2005 Integrity Management Program review, BP shared its Facility Integrity Management Program with PHMSA. At that time, BP also shared its intended pace with the PHMSA inspection team; BP stated that there was a 15 year horizon to cover all BP facilities, whether or not in HCA.

During the Integrated Inspection, BP merely answered the question of how many facilities in HCAs had been covered by the Facility Integrity Management Program, which addressed primarily the threat of internal corrosion. BP did not comprehensively describe the activities it conducts at all its facilities. BP is updating how it communicates the entire breadth of its facility integrity management activities. The full spectrum of threats, including construction defects, equipment failure, external and internal corrosion, incorrect operations, material defects, natural forces, and outside force damage, are currently being addressed with BP's existing program. Identification of risk, equipment failure consequences, and the identification and implementation of preventive and mitigative measures to reduce risk, are currently in place for all facilities within HCAs.

Regarding PCO Item 8, BP will provide the status of integrity management activities for BP-owned facilities that are located in HCAs. The status report will exclude any facilities that BP divests prior to the issuance of the report. BP also will provide revised procedures that describe facility assessment activities.