VENOCO, INC.

July 26, 2012

Mr. Chris Hoidal
PHMSA/Western Region
12300 W. Dakota Ave., Suite 110
Lakewood, Co 80228

Re: Venoco Gas Integrity Management Program Deficiencies, Ref: CPF 5-2012-0014

Dear Mr. Hoidel:

The enclosed documentation with explanation contained in this letter is being submitted in response to the deficiencies found in the Venoco, Inc. Gas Integrity Management Program as stated in your letter to Venoco's Mr. Ed O'Donnell dated May 22, 2012. This documentation is part of Venoco's Gas Integrity Management Program, (IMP).

<u>RESPONSE TO PROPOSED COMPLIANCE ORDER</u>

Item 1 – Venoco failed to identify a segment of the Montalvo Sales Gas pipeline as an HCA and did not appropriately classify the pipeline segment.

Venoco has re-evaluated it's classification of its Montalvo Gas Pipeline and agrees with PHMSA assessment that identifies a segment is within an HCA. As a result, Venoco will include this pipeline in its Gas Pipeline Integrity Management Program and proceed with all required data gathering, assessments, evaluations, and inspections.

Item 2 – Venoco uses In-Line-Inspection (ILI) tools as a method to assess/reassess its pipelines, but failed to specify an ILI tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. Also, Venoco operates some pre-1970 ERW pipelines and claims these pipelines have no history of Stress Corrosion Cracking or seam failure. However, Stress Corrosion Cracking is a time dependent threat and the type of ILI tool or tools selected need to address this possible threat as well.

Enclosed for your review is a copy of a worksheet from our Gas IMP files "VENOCO IMP_ BAP & Mitigation, v2012", revised July 24, 2012. Listed on this worksheet is the specified type of inspection, (including the type of inspection *tool,* when applicable), capable of assessing the identified primary threats, also listed, for each pipeline segment in Venoco's Gas IMP. Venoco has updated this worksheet to include as primary threats *Stress Corrosion Cracking* and *Pre 1970 ERW Pipe* to the pipeline segments within our Gas IMP where the possibility of these threats may exist.

Venoco believes this worksheet demonstrates compliance in accordance with **§ 192.917, §192.921 and ASME/ANSI B31.8S section 6.2 in selecting the appropriate internal inspection tools for the covered segment.** In addition, Venoco believes it also demonstrates compliance in accordance with **ASME/ANSI B31.8S section 6.3** (copy enclosed) which states that Pressure Testing is an appropriate *method* for assessing Time Dependent threats including Stress Corrosion Cracking and Manufacturing

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and Related Defects including pipelines comprised of low frequency welded electric resistance welded (ERW) pipe which may include certain Pre 1970 ERW pipe.

Our review of the operating history and maintenance records for the two pipeline segments that possibly include these threats leads us to conclude these potential conditions are "stable". This conclusion is based on the following:

1. In over 30 years of continuous operation these pipeline segments do not have any history of seam failure or SCC.
2. These pipeline segments have never operated under cyclic pressure conditions.
3. These pipeline segments and have not seen an increase in pressure over the Maximum Operating Pressure during the preceding 5 years.
4. These pipeline segments have been successfully pressure tested since their acquisition by Venoco as well as successfully pressure tested by their previous owners/operators.

Following your review of the enclosed documentation with our explanations of **Item 2**, contained in this letter, please further advise as to PHMSA's conclusion with our addressing the proposed compliance order.

SAFETY IMPROVEMENT COST ASOCIATED WITH FILLING THIS COMPLIANCE ORDER

Venoco estimates the cost associated with preparation/revision of plans, procedures, studies and analyses for:

- **Item 1** Approximately $3,500 for manpower, $200 for materials, and $25,000 to complete a baseline inspection for the Montalvo Sales Gas Line. Total: $28,700.
- **Item 2** Approximately $500 for manpower. Total: $500

Venoco estimates the cost associated with replacements, additions and other changes to pipeline infrastructure for:

- **Item 1** Approximately $2,000 for minor piping modifications associated with completing a baseline inspection for the Montalvo Sales Gas Line. Total: $2,000.
- **Item 2** No cost estimated since no changes to pipeline infrastructure.

Should you have any questions concerning this material or require further clarification, please contact Vince Eccleston at 661-617-8947 or myself at 805-745-2259.

Sincerely,

Keith Wenal
Manager – Health, Environment and Safety

Enclosures

cc:

L. Huskins	w/attachments
S. English	“ “
J. Holm	“ “
J. MacDonald	“ “
J. Hollis	“ “
D. Taylor	“ “
V. Eccleston	w/o attachments

damage that has rerounded under the influence of internal pressure in the pipe may challenge the lower limits of reliable detection of both the standard and high-resolution tools. There has been limited success identifying third-party damage using magnetic-flux leakage tools. MFL tools are not useful for sizing deformations.

6.2.4 All Other Threats. In-line inspection is typically not the appropriate inspection method to use for all other threats listed in para. 2.

6.2.5 Special Considerations for the Use of In-Line Inspection Tools

(a) The following shall also be considered when selecting the appropriate tool:

(1) Detection Sensitivity. Minimum defect size specified for the ILI tool should be smaller than the size of the defect sought to be detected.

(2) Classification. Differentiation between types of anomalies.

(3) Sizing Accuracy. Enables prioritization and is a key to a successful integrity management plan.

(4) Location Accuracy. Enables location of anomalies by excavation.

(5) Requirements for Defect Assessment. Results of ILI have to be adequate for the specific operator's defect assessment program.

(b) Typically, pipeline operators provide answers to a questionnaire provided by the ILI vendor that should list all the significant parameters and characteristics of the pipeline section to be inspected. Some of the more important issues that should be considered are as follows:

(1) Pipeline Questionnaire. Review of pipe characteristics, such as steel grade, type of welds, length, diameter, wall thickness, elevation profiles, etc. Also, identification of any restrictions, bends, known ovalities, valves, unbarred tees, couplings, and chill rings the ILI tool may need to negotiate.

(2) Launchers and Receivers. Should be reviewed for suitability, since ILI tools vary in overall length, complexity, geometry, and maneuverability.

(3) Pipe Cleanliness. Can significantly affect data collection.

(4) Type of Fluid. Gas or liquid, affecting the possible choice of technologies.

(5) Flow Rate, Pressure, and Temperature. Flow rate of the gas will influence the speed of the ILI tool inspection. If speeds are outside of the normal ranges, resolution can be compromised. Total time of inspection is dictated by inspection speed, but is limited by the total capacity of batteries and data storage available on the tool. High temperatures can affect tool operation quality and should be considered.

(6) Product Bypass/Supplement. Reduction of gas flow and speed reduction capability on the ILI tool may be a consideration in higher velocity lines. Conversely, the availability of supplementary gas where the flow rate is too low shall be considered.

(c) The operator shall assess the general reliability of the ILI method by looking at the following:

(1) confidence level of the ILI method (e.g., probability of detecting, classifying, and sizing the anomalies)

(2) history of the ILI method/tool

(3) success rate/failed surveys

(4) ability of the tool to inspect the full length and full circumference of the section

(5) ability to indicate the presence of multiple cause anomalies

Generally, representatives from the pipeline operator and the ILI service vendor should analyze the goal and objective of the inspection, and match significant factors known about the pipeline and expected anomalies with the capabilities and performance of the tool. Choice of tool will depend on the specifics of the pipeline section and the goal set for the inspection. The operator shall outline the process used in the integrity management plan for the selection and implementation of the ILI inspections.

6.2.6 Examination and Evaluation. Results of in-line inspection only provide indications of defects, with some characterization of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation. The time frame is discussed in para. 7. (04)

Examination consists of a variety of direct inspection techniques, including visual inspection, inspections using NDE equipment, and taking measurements, in order to characterize the defect in confirmatory excavations where anomalies are detected. Once the defect is characterized, the operator must evaluate the defect in order to determine the appropriate mitigation actions. Mitigation is discussed in para. 7.

6.3 Pressure Testing

Pressure testing has long been an industry-accepted method for validating the integrity of pipelines. This integrity assessment method can be both a strength test and a leak test. Selection of this method shall be appropriate for the threats being assessed.

ASME B31.8 contains details on conducting pressure tests for both post-construction testing and for subsequent testing after a pipeline has been in service for a period of time. The Code specifies the test pressure to be attained and the test duration in order to address certain threats. It also specifies allowable test mediums and under what conditions the various test mediums can be used.

The operator should consider the results of the risk assessment and the expected types of anomalies to determine when to conduct inspections utilizing pressure testing.

6.3.1 Time-Dependent Threats. Pressure testing is appropriate for use when addressing time-dependent threats. Time-dependent threats are external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanisms.

(04) **6.3.2 Manufacturing and Related Defect Threats.** Pressure testing is appropriate for use when addressing the pipe seam aspect of the manufacturing threat. Pressure testing shall comply with the requirements of ASME B31.8. This will define whether air or water shall be used. Seam issues have been known to exist for pipe with a joint factor of less than 1.0 (e.g., lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is comprised of low-frequency welded electric resistance welded (ERW) pipe or flash-welded pipe.

When raising the MAOP of a steel pipeline or when raising the operating pressure above the historical operating pressure (i.e., highest pressure recorded in 5 years prior to the effective date of this Standard), pressure testing must be performed to address the seam issue.

Pressure testing shall be in accordance with ASME B31.8, to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct tests for both post-construction and in-service pipelines.

6.3.3 All Other Threats. Pressure testing is typically not the appropriate integrity assessment method to use for all other threats listed in para. 2.

6.3.4 Examination and Evaluation. Any section of pipe that fails a pressure test shall be examined in order to evaluate that the failure was due to the threat which the test was intended to address. If the failure was due to another threat, the test failure information must be integrated with other information relative to the other threat and the segment reassessed for risk.

6.4 Direct Assessment

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity.

6.4.1 External Corrosion Direct Assessment (ECDA) for the External Corrosion Threat. External corrosion direct assessment can be used for determining integrity for the external corrosion threat on pipeline segments. The process integrates facilities data, and current and historical field inspections and tests, with the physical characteristics of a pipeline. Nonintrusive (typically aboveground or indirect) inspections are used to estimate the success of the corrosion protection. The ECDA process requires direct examinations and evaluations. Direct examinations and evaluations confirm the ability of the indirect inspections to locate active and past corrosion locations on the pipeline. Post-assessment is required to determine a corrosion rate to set the reinspection interval, reassess the performance metrics and their current applicability, and ensure the assumptions made in the previous steps remain correct.

The ECDA process therefore has the following four components:

(a) pre-assessment
(b) inspections
(c) examinations and evaluations
(d) post-assessment

The focus of the ECDA approach described in this Standard is to identify locations where external corrosion defects may have formed. It is recognized that evidence of other threats such as mechanical damage and stress corrosion cracking (SCC) may be detected during the ECDA process. While implementing ECDA and when the pipe is exposed, the operator is advised to conduct examinations for nonexternal corrosion threats.

The prescriptive ECDA process requires the use of at least two inspection methods, verification checks by examination and evaluations, and post-assessment validation.

For more information on the ECDA process as an integrity assessment method, see Nonmandatory Appendix B, para. B1.

6.4.2 Internal Corrosion Direct Assessment Process (ICDA) for the Internal Corrosion Threat. Internal corrosion direct assessment can be used for determining integrity for the internal corrosion threat on pipeline segments that normally carry dry gas but may suffer from short-term upsets of wet gas or free water (or other electrolytes). Examinations of low points or at inclines along a pipeline, which force an electrolyte such as water to first accumulate, provide information about the remaining length of pipe. If these low points have not corroded, then other locations further downstream are less likely to accumulate electrolytes and therefore can be considered free from corrosion. These downstream locations would not require examination.

Internal corrosion is most likely to occur where water first accumulates. Predicting the locations of water accumulation (if upsets occur) serves as a method for prioritizing local examinations. Predicting where water first accumulates requires knowledge about the multiphase flow behavior in the pipe, requiring certain data (see para. 4). ICDA applies between any feed points until a new input or output changes the potential for electrolyte entry or flow characteristics.

Examinations are performed at locations where electrolyte accumulation is predicted. For most pipelines it is expected that examination by radiography or ultrasonic NDE will be required to measure the remaining wall thickness at those locations. Once a site has been exposed, internal corrosion monitoring method(s) [e.g.,

VENOCO, INC. GAS IMP RISK RANK AND SCHEDULE

Date Updated: 07/24/2012
File Name: VENOCO IMP_ BAP & Mitigation, v2012
PHMSA Operator ID: # 31296

Risk Rank	HCA Segment Name	Avg Risk Rank Score	Date of Last Assessment	Assess Interval	Scheduled Date of Next Assessment	Assess Method (ILI, Pressure Test, Other) and type of ILI Tools Used (smart pigs)	Basis for Assesment Method (Primary Threats Identified)	HCA ID Method	CL	MILES	Nominal Outside Diameter	MAOP	PIR in Feet	Buffer Zone (feet)	Comments and Validation:
1	Union Island Gas Line Segment # 2 (Northern California)	6.87	7-Jun-11	5	5-Jun-16	ILI (High Resolution Magnetic Flux Leakage & Deformation)	External corrosion, and 3rd party damage	1	3,4	20.52	12.000	816	237	*10*	Changed seven year re-assessment interval to five year interval due to increased potential for third party damage.
2	Union Island Gas Line Segment # 1 (Northern California)	7.20	7-Jun-11	5	5-Jun-16	ILI (High Resolution Magnetic Flux Leakage & Deformation)	External corrosion, and 3rd party damage.	1	1,2	14.80	12.000	816	237	*10*	Changed seven year re-assessment interval to five year interval due to increased potential for third party damage.
3	Ellwood Sales Gas Line (Southern California)	8.07	1-Aug-02	7	30-Jul-09	Pressure test	External corrosion, 3rd party damage, Pre 1970 ERW pipe, Stress Corrosion Cracking.	1	3,4	0.64	6.000	1,000	131	*10*	
4	Ryer Island Segment #2 (Northern California)	8.13	27-Sep-11	7	25-Sep-18	Pressure test	External corrosion, 3rd party damage, Pre 1970 ERW pipe, Stress Corrosion Cracking.	1	1,2	1.50	12.000	720	222	*10*	
5	Montalvo Sales Gas Line (Southern California)	8.27		7	29-Dec-06	Pressure test	External corrosion, and 3rd party damage.	1	1,3	0.92	5.000	330	63	*10*	

Total Miles (same as annual report total)	38.38
Total Miles inspected to date (IMP & non-IMP)	
Total Miles of HCA pipeline in IM program	
Total Miles of HCA miles inspected	