

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 28, 2009

Mr. David Wallen
Vice President
MoGas Pipeline LLC
110 Algana Ct.
St. Peters, MO 63376

CPF-3-2009-1013M

Dear Mr. Wallen:

On March 19-21, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Missouri Public Service Commission, pursuant to Chapter 601 of 49 United States Code inspected the MoGas Pipeline (previously Missouri Pipeline Company [MPC]) integrity management (IM) plan and procedures in St. Peters, Missouri.

On the basis of the inspection, PHMSA has identified apparent inadequacies within MPC's plans or procedures, as described below:

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (see §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, see §192.7) for more detailed information on the listed element.)

1. **§192.911(a) An identification of all high consequence areas, in accordance with §192.905.**

Item 1A: §192.905 How does an operator identify a high consequence area?
(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

MPC's procedures do not delineate a method for capturing new high consequence areas (HCAs) through changes in building use and occupancy and new construction. The method should include forms for capturing identified site and HCA information from routine patrols and procedures for analyzing this information in a timely way.

2. **§192.911(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.**

§ 192.919 What must be in the baseline assessment plan? An operator must include each of the following elements in its written baseline assessment plan: .

....

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment. .

....

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

- **Item 2A: §192.919(e)**
In order to perform assessments in a manner that minimizes safety and environmental risks, MPC has linked the IM plan to company operations and maintenance (O&M) procedures. The O&M procedures that were provided for review, however, did not adequately address employee safety.
 - **Item 2B: §192.921(a)(1)**
MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation of any conditions that are discovered. These elements include the selection of assessment methods (in-line inspection or external corrosion direct assessment).
 - **Item 2C: §192.921(a)(4)**
MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation of any conditions that are discovered. These elements include the required notification to PHMSA and the applicable state agencies of the use of other technology (e.g., assessment of cased pipe), if other technology is used.
3. **§192.911(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.**

§192.917(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see §192.7), section 2...

§192.917(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

§192.917(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in

accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

- **Item 3A: §192.917(a)**

The threat identification process documented in the MPC IM plan appendix included the 9 threat categories listed in ASME/ANSI B31.8S, section 2.2, but did not address the cyclic fatigue evaluation required by 192.917(e)(2) or interactive threats as required by ASME/ANSI B31.8S, section 2.2. Therefore, MPC did not perform an interactive threat analysis or cyclic fatigue evaluation as part of the threat identification process.

A basis is not provided for elimination of the following threats:

- The MPC IM plan stated that third party damage is not an applicable threat to any HCA. A valid basis for this conclusion is not presented. It is noted, however, that third party damage was included as a factor in the risk scoring model.
- Equipment failure was not considered an applicable threat to any HCA. A valid basis for this conclusion is not presented.

- **Item 3B: §192.917(c)**

The MPC risk assessment model must be revised to address the following issues:

- The MPC risk model description does not specify how leak history from non-covered segments with similar characteristics to the covered segments, would be incorporated in the risk scoring.
- The weighting of the throughput and customer interrupt factors may be too high relative to public safety factors (e.g., population density) in consequence scoring by the risk model.
- The MPC risk model description does not specify how assessment results will be incorporated into the risk scoring.

Also, MPC does not have a provision for periodic review to incorporate new information and revise the risk assessment. The MPC IM plan section 4.2, which addresses data, is very brief and does not document program requirements for data updates or data integration when new information is identified.

- **Item 3C: §192.917(e)(1)**

Integration of data on encroachments and foreign line crossings with integrity assessment results is not required in the MPC program. The method for performing this data integration has not been defined or documented.

4. **§192.911(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.**

Item 4A: §192.925(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE RP 0502–2002 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

The deadline for completing integrity assessments on at least 50% of HCA mileage is December 17, 2007. MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation of any conditions that are discovered. These elements include an External Corrosion Direct Assessment (ECDA) Plan, if ECDA is chosen as an assessment method.

5. **§192.911(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.**

Item 5A: §192.933(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation of any conditions that are discovered. These elements include the discovery and subsequent remediation of discovered conditions.

6. **§192.911(f) A process for continual evaluation and assessment meeting the requirements of §192.937.**

§192.937(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section.

§192.937(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

- **Item 6A: §192.937(a)**
MPC procedures do not base maximum reassessment intervals on MAOP. Instead, intervals are based on normal operating pressure, which has resulted in longer intervals than allowed for some segments.
- **Item 6B: §192.937(b)**
MPC has not yet developed details of a process for completing periodic evaluations, which would include the frequency at which these evaluations will be performed.

7. **§192.911(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.**

§192.935(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety.....

§192.935(b)(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to

third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

§192.935(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV)*. If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

- **Item 7A: §192.935(a)**
MPC has no documented process for evaluating a wide range of potential preventive and mitigative measures based on threats, risk assessment, and documented decision criteria.
- **Item 7B: §192.935(b)(1)**
MPC has no documented process for conducting root cause analysis for events to be recorded in their excavation damage data base in order to identify additional preventive and mitigative measures. In addition, the MPC O&M manual does not have procedures for monitoring excavations on transmission pipeline right-of-ways that match MPC's current practice for monitoring such excavations.
- **Item 7C: §192.935(c)**
The MPC evaluation of ASVs/RCVs does not address all factors required by the rule and does not consider the potential safety benefits of installing new valves.

8. §192.911(j) Record keeping provisions meeting the requirements of §192.947.

Item 8A: §192.947(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

Procedures do not require that records specified in 192.947 be maintained for the useful life of the pipeline; for example, analysis supporting the placement of additional ROW markers was not documented or maintained in IM program records as required.

9. §192.911(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

Item 9A: ASME/ANSI B31.8S Section 11 (a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural and organizational changes to the system whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:

- (1) Reason for change**
- (2) Authority for approving changes**
- (3) Analysis of implications**
- (4) Acquisition of required work permits**
- (5) Documentation**
- (6) Communication of change to affected parties**
- (7) Time limitations**
- (8) Qualification of staff**

MPC does not have a documented management of change process along with implementing procedures that develop the IM rule requirements in terms of MPC's specific organization. Although several past changes to the baseline assessment plan have been documented, a procedure for making such changes is not in the IM plan.

10. §192.911(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

ASME/ANSI B31.8S Section 12.2(b) - Specifically, activities that should be included in the quality control program are as follows:

(3) Results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.

(4) The personnel involved in the integrity management program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness, and qualification, and the processes for their achievement, shall be part of the quality control plan.

ASME/ANSI B31.8S Section 12.2(c) - When an operator chooses to use outside resources to conduct any process, for example pigging, that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program.

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(b) *Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person—*

- (1) Who conducts an integrity assessment allowed under this subpart; or**
- (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or**
- (3) Who makes decisions on actions to be taken based on these assessments.**

- **Item 10A: §192.911(l)**

MPC has not specified a maximum interval for performing program reviews [ASME/B31.8S, Section 12.2(b)(3)], the scope of the reviews, and the criteria for specifying corrective actions from these reviews. An annual update of integrity data and risk assessments is required; this would provide a logical interval for performing the required program reviews.

MPC has not defined minimum qualifications for all personnel responsible for IM program implementation consistent with ASME/B31.8S, Section 12.2(b)(4) as referenced by the rule.

MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation of any conditions that are discovered. These elements include quality assurance of work from outside vendors consistent with ASME/B31.8S, Section 12.2(c) as referenced by the rule.

- **Item 10B: §192.915(b)**

MPC has not fully defined or documented key IM program elements that are required to ensure successful completion of integrity assessments and remediation

of any conditions that are discovered. These elements include definition of qualifications for personnel conducting assessments and evaluating assessment results.

- 11. Item 11A: §192.911(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—**
- (1) OPS; and**
 - (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.**

Although MPC is a small organization (which facilitates internal communication), MPC has individuals with IM responsibilities in dispersed locations. The IM plan, however, does not include program requirements to ensure regular internal communications on the IM program.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. 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). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 3-2009-1013M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*