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Certified Mail – Return Receipt Requested

June 7, 2007

Mr. Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

Re: Inspection of Merit Energy Company's Bairoil, Wyoming procedures conducted on October 10-13, 2006 by representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and recorded as CPF 5-2007-5010M.

Dear Mr. Hoidal:

In regard to the subject inspection, Merit Energy Company has undertaken an in-depth evaluation of its Operations and Maintenance Procedures and has addressed each of the alleged inadequacies identified during the audit. To fully explain the steps taken by Merit Energy Company in rectifying the issues we have attached the following:

1. A copy of the "Notice of Amendment" letter dated February 16, 2007.

2. A .pdf file of each procedure from our revised O&M Manual addressing the NOA items as follows:
    - NOA Item 1 – Section 2.15 and Section 2A.15
    - NOA Item 2 – Section 2.15 and Section 2A.15
    - NOA Item 3 – Section 2.15 and Section 2A.15
    - NOA Item 4 – Section 2.15 and Section 2A.15
    - NOA Item 5 – Section 2.11.5
    - NOA Item 6 – Section 2.11.5
    - NOA Item 7 – Section 2.11.5
    - NOA Item 8 – Section 2.12
    - NOA Item 9 – Section 2.12.1.9
    - NOA Item 10 – Section 2.12.1.4
    - NOA Item 11 – Section 2.12.1.6
    - NOA Item 12 – Section 2.12.1.7
    - NOA Item 13 – Section 2.12.1.7
    - NOA Item 14 – Section 2.12.1.7
    - NOA Item 15 – Section 2.12.1.8

- NOA Item 16 – Section 2.12.1.10
- NOA Item 17 – Section 2.12.2
- NOA Item 18 – Section 2.12.2
- NOA Item 19 – Section 2.12.2
- NOA Item 20 – Section 2.12.4
- NOA Item 21 – Section 2.12.4
- NOA Item 22 – Section 2.12.4
- NOA Item 24 – Section 2.3 (Note: Item 23 not shown on letter)

3. CD containing a copy of this letter and other supporting documentation.

During our procedure manual evaluation we determined that certain other sections of the manual might be revised to improve its "readability" and describe current regulatory requirements more fully and thus we have performed a major revision to accomplish this task. Copies of the complete manual are available upon request.

Should there be any questions or if additional information is required, please contact me at the address below.

Sincerely,

Jason Wacker

Jason Wacker
East Rockies Regional Manager
13727 Noel Rd., Suite 500
Dallas, TX 75240

Cc:

Bill Ellsworth
Merit Energy Company
Bairoil, WY

Michael Reagan
Optimized Pipeline Solutions, Inc.
Crowley, TX

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

SENT TO COMPLIANCE REGISTRY
Hardcopy__ Electronically ✓
# of Copies 1 / Date 2/16/07

February 16, 2007

Mr. Tod Flott
VP, Northern Division
Merit Energy Company
13727 Noel Road, Suite 500
Dallas, TX 75240-5240

CPF 5-2007-5010M

Dear Mr. Flott:

On October 10-13, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your procedures for Bairoil CO_2 Pipeline in Bairoil, Wyoming.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Merit Energy Company's procedures and are described below:

1. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

   (a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

   §195.408 Communications.
   (a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.

At the time of the inspection, the operator did not have procedures requiring a communication system to provide for the transmission of information needed for the safe operation of the pipeline system.

2. **§195.408 Communications.**

> **(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:**
> **(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;**

At the time of the inspection, the operator did not have procedures requiring the operator to receive notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and to send this information to appropriate personnel or government agencies for corrective action.

3. **§195.408 Communications.**

> **(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:**
> **(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies;**

At the time of the inspection, the operator did not have procedures requiring the operator to have a communications system that allows conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.

4. **§195.408 Communications.**

> **(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:**
> **(4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.**

At the time of the inspection, the operator did not have procedures requiring the operator to provide communication with fire, police, and other public officials during emergency conditions, including natural disasters.

5. **§195.420 Valve maintenance.**

> **(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.**

At the time of the inspection, the operator did not have procedures requiring each valve that is necessary for the safe operation of its pipeline systems to be maintained in good working order at all times.

6. **§195.420 Valve maintenance.**

(b) Each operator shall, at intervals not exceeding 7 1/2 months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

At the time of the inspection, the operator did not have procedures requiring valve inspection intervals not exceeding 7 1/2 months, but at least twice each calendar year, and that each mainline valve be inspected to determine that it is functioning properly.

7. **§195.420 Valve maintenance.**

(b) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

At the time of the inspection, the operator did not have procedures requiring protection for each valve from unauthorized operation and from vandalism.

8. **§195.555 What are the qualifications for supervisors?**

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402(c)(3) for which they are responsible for insuring compliance.

At the time of the inspection, the operator did not have procedures requiring supervisors to maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402(c)(3) for which they are responsible for insuring compliance.

9. **§195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?**

(c) Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with Sec. 195.571.

At the time of the inspection, the operator did not have procedures requiring the company to maintain the test lead wires.

10. **§195.569 Do I have to examine exposed portions of buried pipelines?**

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

At the time of the inspection, the operator did not have procedures requiring examination of exposed portions of a buried pipeline.

11. §195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

At the time of the inspection, the operator did not have procedures requiring the pipeline's cathodic protection comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96.

12. §195.573 What must I do to monitor external corrosion control?

a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:
(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

At the time of the inspection, the operator did not have procedures requiring assessment of the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96.

13. §195.573 What must I do to monitor external corrosion control?

c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	**Check frequency**
Rectifier................................ Reverse current switch Diode Interference bond whose failure would jeopardize structural protection	**At least six times each calendar year, but with intervals not exceeding 2 ½ months**
Other interference bond	**At least once each calendar year, but with intervals not exceeding 15 months.**

At the time of the inspection, the operator did not have procedures requiring interference bond whose failure would jeopardize structural protection (critical bonds) be inspected six times each calendar year, but at intervals not exceeding 2 ½ months.

14. §195.573 What must I do to monitor external corrosion control?

> **(e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).**

At the time of the inspection, the operator did not have procedures requiring the operator to correct any identified deficiency in corrosion control.

15. §195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?

> **(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.**
> **(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.**
> **(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.**
> **(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.**
> **(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.**

At the time of the inspection, the operator did not have procedures requiring electrical isolation of applicable pipeline facilities and the inspections, tests, and safeguards required to insure electrical isolation of the pipeline.

16. §195.577 What must I do to alleviate interference currents?

> **(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.**
> **(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.**

At the time of the inspection, the operator did not have procedures for alleviating interference currents.

17. §195.579 What must I do to mitigate internal corrosion?

(a) General. If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

At the time of the inspection, the operator did not have procedures to investigate the corrosive effect of carbon dioxide on the pipeline and to take adequate steps to mitigate any internal corrosion discovered.

18. §195.579 What must I do to mitigate internal corrosion?

c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

At the time of the inspection, the operator did not have procedures requiring the inspection of the internal surface for evidence of corrosion whenever pipe is removed from a pipeline.

19. §195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

(a) You 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.
(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will-
(1) Only be a light surface oxide; or
(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

At the time of the inspection, the operator did not have procedures stating the criteria to identify which pipelines will be protected against atmospheric corrosion and the coating material to be used.

20. §195.585 What must I do to correct corroded pipe?

(a) General corrosion. If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you-
(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

At the time of the inspection, the operator did not have procedures outlining the action to be taken to correct generally corroded pipe.

21. §195.585 What must I do to correct corroded pipe?

(b) Localized corrosion pitting. If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

At the time of the inspection, the operator did not have procedures outlining the action to be taken to correct pipe with localized corrosion.

22. §195.587 What methods are available to determine the strength of corroded pipe?

Under Sec. 195.585, you may use the procedure in ASME B31G, ``Manual for Determining the Remaining Strength of Corroded Pipelines," or the procedure developed by AGA/Battelle, ``A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)," to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

At the time of the inspection, the operator did not have procedures to determine the strength of corroded pipe.

24. §195.589 What corrosion control information do I have to maintain?

(a) You must maintain current records or maps to show the location of--
(1) Cathodically protected pipelines;
(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and
(3) Neighboring structures bonded to cathodic protection systems.
(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.
(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

At the time of the inspection, the operator did not have procedures outlining the retention of corrosion control information and records.

Response to this Notice

This Notice is provided pursuant to 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 the Notice of Amendment portion of this document and note the response options. Failure to respond within 30 days of receipt of this Notice will be deemed a waiver of your right to contest the allegations set forth above and will authorize the Associate Administrator for Pipeline Safety, without further notice, to find facts as alleged in this Notice and to issue an Order Directing Amendment.

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 5-2007-5010M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

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

cc: PHP-60 Compliance Registry
PHP-500 B. Brown (# 116814)

2A.15 COMMUNICATIONS & CONTROL SYSTEM [§195.408]

The Bairoil CO2 Pipeline System is equipped with a monitoring system that is monitored by plant personnel at the Bairoil CO2 recycle plant control room. Merit operating personnel has the ability to change flows manually. Pressure and temperature on the pipeline is controlled by ExxonMobil personnel at the Chute Creek Plant. Overpressure prevention of the Merit Bairoil CO2 Pipeline is accomplished through the installation of two (2) pressure relief valves, one at either end of the pipeline.

2A.16 PERSONNEL REVIEW [§195.402(c)(13)]

The Bairoil CO2 Pipeline System is operated consistent with Section 2.

2A.17 SAFETY

2A.17.1 PREVENTION OF ACCIDENTAL IGNITION [§195.402(C)(11)]

The Bairoil CO2 Pipeline System transports CO2 which is non-combustible. This section does not apply.

2A.17.2 FIRE FIGHTING EQUIPMENT [§195.430]

The Bairoil CO2 Pipeline System transports CO2 which is non-combustible. This section does not apply.

2A.17.3 HIGH HAZARD AREAS [§195.402(c)(4)]

The Bairoil CO2 Pipeline System crosses minor public thoroughfares which could be classified as high hazard areas. The Bairoil CO2 Pipeline System is operated consistent with Section 2.

2A.17.4 SCRAPER HANDLING PROCEDURES [§195.426]

The Bairoil CO2 Pipeline System is operated consistent with Section 2.

2A.17.5 EXCAVATED TRENCH SAFETY [195.402(C)(14)]

The Bairoil CO2 Pipeline System is operated consistent with Section 2.

2A.18 PIPELINE RELOCATION

The Bairoil CO2 Pipeline System is operated consistent with Section 2.

"Pressure, Temperature, Monitoring and Limiting Devices" shall be utilized for these inspections.

Devices found to be operating incorrectly shall be repaired immediately or the system they protect shall be taken out of operation.

2.11.5 VALVE INSPECTION [§195.420]

Pipeline valves required for isolation, blow down of facilities or used in the event of an emergency shall be inspected at intervals not exceeding 7 ½ months, but at least twice per calendar year, to determine that they are in good working order and functioning properly. ***Form OPS.07*** "Valve Inspection Record," will be utilized for these inspections. Valves will either have individual locking devices on each valve or will be located within fenced areas with locked gates.

All electrically operated valves shall be checked both for electrical and manual operation. The Senior Local Manager or designee will prepare a list of those valves required for isolation or blow down. These valves will be inspected using the following procedure:

1. Remove any locking devices attached to the valve being inspected.
2. Inspect the valve for product leakage at flanges, bonnet, stem seals, or packing.
3. If leakage is found note in "remarks" column and attempt to correct by tightening flange bolts, injecting stem sealant, etc., depending on source of leakage. Note any corrective action taken in "repairs" column.

NOTE: THE FOLLOWING STEP ASSUMES THAT THE VALVE BEING INSPECTED IS A MAINLINE VALVE, WHICH IS USUALLY FULLY OPEN. THE PERSON PERFORMING THIS INSPECTION SHOULD NOT PERFORM THIS STEP ON A FULLY-CLOSED VALVE UNTIL ASSURING THAT THE CONSEQUENCES OF OPENING THE VALVE WILL NOT RESULT IN ACCIDENT OR INJURY TO PROPERTY OR PERSONNEL.

THE PERSON PERFORMING AN INSPECTION SHOULD ALSO BE AWARE THAT THE FLOW OF PRODUCT THROUGH THE VALVE WILL DECREASE SOMEWHAT, AND SHOULD ASSURE THAT THIS WILL NOT CREATE AN UPSET IN A PROCESS OR UNIT INVOLVED WITH THIS VALVE.

4. Operate the valve from its fully open position to approximately 10% closed position, noting especially the ease of operation of the hand wheel or other valve operator. If the device exhibits excessive

resistance, attempt to correct by lubrication or other methods as required, depending on the type of valve being inspected. Note these facts in the "remarks" and "greased" columns.

5. Return the valve to its original position and re-install any locking devices.

6. Record all information on the appropriate forms for the system inspection and maintenance records.

2.12 CORROSION [§195.551]

All pipelines and breakout tanks must meet the requirements of Subparts ***D*** and ***F*** of 49 CFR 195. The procedures established in this manual fully satisfy the requirements of Subparts ***D*** and ***F***. All Company pipelines shall be cathodically protected. Supervisors that are responsible for the operations of pipelines will be thoroughly familiar with corrosion control requirements and the procedures to ensure that the requirements are met. Records demonstrating compliance with corrosion control requirements will be maintained according to 195.589.

2.12.1 EXTERNAL CORROSION CONTROL [§195.551]

This manual, in conjunction with the referenced volumes, establish the procedures to be used for the design, installation, operation and maintenance of cathodic protection systems. As stated in Section 2.2.3, these activities will be carried out by or under the direction of individuals qualified in pipeline corrosion control methods.

2.12.1.1 CATHODIC PROTECTION-GENERAL [§195.563(a),(b),(c),&(d)]

Except in unusual circumstances, all company pipelines will be cathodically protected. The following conditions will be used as a guide to determine the requirement for cathodic protection for a specific pipeline:

1. Each buried or submerged pipeline that is constructed, relocated, replaced or otherwise changed after the applicable dates shown in 196.401(c) must have cathodic protection applied within one year after construction or modification is complete.

2. Each buried or submerged pipeline which has been converted from a service not jurisdictional under Part 195 into a service that is jurisdictional must have cathodic protection if a) the pipeline has cathodic protection that in general meets requirements, or b) if the segment is relocated replaced or altered.

4. Training in the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated emergency pipeline condition. [§195.402(a)(5)]

5. Maintenance personnel will also be trained to safely repair facilities using appropriate precautions such as isolation, lockout/tagout and purging.

6. Training in the recognition of conditions that might lead to emergencies and the mitigation of this condition. [§195.403(a)(3)]

7. Training in steps to reduce the likelihood of accidental release of transported material. [§195.403(a)(4)]

8. Training in the recognition of Abnormal Operating Conditions contained in Section 3 of this manual and in the recognition of Safety Related Conditions contained in Section 2.8 of this manual.

2.2.4 PERIODIC REVIEW OF TRAINING [§195.403(b)(1)& (2) & 195.403(c)]

The emergency response training program will be reviewed with the operating personnel once each calendar year at an interval not exceeding 15 months with the intent of evaluating the personnel's performance in meeting the objectives of the emergency response training program. Each element's contribution to the overall training program will be evaluated with the intent of identifying any issues and making appropriate changes when required. Changes will be made to ensure that the program is implemented and documented effectively. The senior local manager or designee will be responsible for conducting the evaluation and the results of the evaluation will be documented on the appropriate "emergency training evaluation" form found in the front of this manual.

2.3 OPERATING HISTORY, MAPS & RECORDS [§195.404 & 195.402(c)(1)]

An operating history, including daily operating data will be kept by the operator as described in this manual. This operating history will be maintained by the Senior Local Manager or designee and available to personnel as needed. The operator's logs, charts, and other operating records will be kept for three years.

1. Daily Operating Data which includes, at a minimum, the following information:

   Date
   Time
   Flow Rate Pumped
   Flow Rate Received
   Discharge Pressure at each pump station

Pressure at each receiving station

Note: Pressure and flow information recorded on charts will document portions of the operating history requirements.

2. Operating and maintenance records will be maintained for the periods indicated. These records are as follows:

   A. Current location and identification of each breakout tank, pump station, scraper and sphere facility, pipeline valve facility, facilities to which 195.402(c)(9) applies, rights of way and safety devices to which 195.428 applies.(Current maps).[§195.404(a)(1)]

   B. Any emergency or abnormal operation and the response made (3 years). [§195.404(b)(2)]

   C. Date, location, and description of each repair made to pipe will be kept for the life of the pipeline. [§195.404(c)(1)]

   D. Date, location, and description of each repair made to parts of pipeline other than pipe will be kept for at least one year. [§195.404(c)(2)]

   E. Record of each right-of-way and navigable water inspection (2 years or until next inspection, whichever is longer). [§195.412]

   F. Records of corrosion monitoring of protected pipe, unprotected pipe, exposed pipe inspections, corrosion coupon analysis and internal corrosion inspections. (5 Years), [§195.569, .573(a), .573(b), .579(b)(3) and .579(c)] for Life of Pipeline.

   G. Records of rectifier inspections (5 Years). [§195.573(c)]

   H. Records of all valve and overpressure safety device inspections (2 years or until the next inspection, whichever is longer). [§195.420, 195.428(a), 195.404(a)(1)(ii) & (iv)]

   I. Inspection and test records for relief valves on HVL tanks (2 years) [§195.428(b)]

   J. Inspection and test records for firefighting equipment (2 years) [§195.430]

   K. inspection records for breakout tanks (2 years). [§195.432]

   L. Training, certification, and performance records for all personnel as required by Operator Qualification regulations.

   M. Records pertaining to continuing public education programs. (2 years) [§195.440]

3. All other buried or submerged pipelines that are effectively coated will be cathodically protected.
4. Bare pipelines must be cathodically protected.

2.12.1.2 PIPELINES - UNPROTECTED [§195.563(e), 195.573]

Unprotected pipe (no cathodic protection) must be evaluated to determine if active corrosion is present. The evaluation may be through electrical survey or other means such as review and analysis of leak repair records, inspection records, corrosion monitoring records, exposed pipe inspection reports and/or the pipeline environment. This evaluation must be conducted every three years, not to exceed 39 months. Whenever active corrosion is detected, the segment must be cathodically protected.

2.12.1.3 PIPELINES BREAKOUT TANKS & BURIED PUMPING STATION PIPING [§195.563(d)]

Breakout tank areas and buried pumping station piping may be exempted to cathodic protection requirements in certain circumstances. However, company policy will be that all breakout tanks and buried station piping will be cathodically protected.

2.12.1.4 EXAMINATION OF EXPOSED PIPE [§195.569]

Whenever any buried pipe is exposed for any reason, it shall be examined for evidence of external corrosion if bare and for evidence of coating deterioration if coated. Whenever general corrosion or pitting is found on the exterior of the pipe, the extent and severity of corrosion will be further investigated ***Form OPS.13*** "Pipe Inspection Report" will be used to document inspections. The following items should be evaluated and documented on the form: rust condition, pitting or corrosion condition, and condition of coating. Consideration should also be given to the proximity and condition of existing adjacent underground structures such as conduits, ducts, sewer lines and similar structures, including abandoned facilities, which might provide a potential migration path for leaking material.

The determination of whether a suspected or known corrosion condition should be considered active corrosion should be made by an individual that is trained and competent to render such a determination. The following factors should be considered in this determination:

a. Leak frequency
b. Pressure
c. Location of piping
d. Location of other structures

If it is determined that active corrosion exists, the following corrective measures will be considered.

a. Install cathodic protection on the existing pipe
b. Up rate coating and cathodic protection on existing pipe
c. Replacement of pipe with coated and cathodically protected pipe
d. Controlling stray current
e. Abandonment

Note: Whenever it is determined that corrosion has reduced pipe wall thickness to a level below minimum wall thickness required for safe operation of the pipeline, the pipeline pressure will be reduced to a level consistent with remaining wall thickness or the pipe will be replaced with effectively coated and protected pipe.

2.12.1.5 PROTECTIVE COATING [§195.557, 195.559, 195.561]

Except for bottoms of above ground breakout tanks, each buried or submerged pipe and pipeline component meeting the date requirements found in 195.401(c) will be externally coated. Additionally, pipelines converted under 195.5 and has an external coating before being placed into service or is a segment that is relocated, replaced or substantially altered will be externally coated. Coating material will be designed to prevent external corrosion and which has sufficient adhesion to prevent moisture penetration, is sufficiently ductile to prevent cracking, has sufficient strength to prevent damage due to handling or soil stress, is able to support cathodic protection and possesses adequate insulating qualities. The surface of the pipe or component must be properly cleaned and coating must be applied according to manufacturer's specifications.

The pipe coating will be inspected immediately prior to lowering it into the ditch and backfilling. It will be inspected visually and 100% electrically inspected using a conductive contact with a holiday detector having the appropriate voltage setting for the coating used. Any damage will be repaired using appropriate procedures. The pipe coating will be protected from adverse ditch conditions or damage from supporting blocks. The backfill material used will be free of rocks adjacent to the pipe or a rock shield will used to protect the pipe coating.

If the pipe is being installed by boring, precautions will be taken to minimize the damage to the coating, including the application of a special coating in addition to, and on top of, the standard corrosion prevention material. A Company representative will be present during all boring operations where potential damage to pipe coating could occur.

2.12.1.6 CATHODIC PROTECTION [§195.571]

The cathodic protection system must provide a level of protection sufficient to mitigate corrosion which could lead to structural failure. Standard criteria for cathodic protection systems shall be a minimum negative reading of -0.85 volts from the structure (pipeline) to ground using a Copper/Copper Sulfate half cell. Voltage (IR) drop, other than that across the structure-electrolyte boundary, can affect this reading. This effect is normally negligible. However, these additional IR drops must be considered when interpreting data for compliance with the -0.85 volt criteria. Sound engineering practices will be applied when considering the affects of voltage drop and may include, but not be limited to the following:

- Measuring or calculating the voltage drop.
- Reviewing the historical performance of the cathodic protection system.
- Evaluating the physical and electrical characteristics of the pipe and environment.
- Determining whether or not there is physical evidence of corrosion.

A minimum negative polarization voltage shift of 100 millivolts is also acceptable.

Other criteria, if used, are explained in Section 2A.12.1.6 of this manual. Nonetheless, criteria must comply with paragraphs 6.2 and 6.3 of NACE Standard RP069-96. If corrosion is found to persist at or above (more negative) of this potential, further investigation shall be made and different criteria used if necessary.

The level of cathodic protection voltage should be controlled so that bonding of coating material to the pipe is not adversely affected. General guidelines for Copper/Copper Sulfate half cell voltage readings are given in the table below. Voltages equal to or less than those listed in the table below present minimal potential for coating disbondment. Voltages in excess of those listed may affect coating bonding and should be evaluated by a cathodic protection professional.

Coating Type	Half Cell Reading
Pritec	-2.50
Extrucoats (Entec, Yellow jacket, etc)	-1.80
TGF-3	-1.50
Fusion Bond Epoxy (FBE)	-1.30

2.12.1.7 <u>CATHODIC PROTECTION MONITORING</u> [§195.573]

Tests shall be conducted once per calendar year, not to exceed 15 months, to determine if the cathodic protection system is adequate. Results of tests will be recorded on ***Form OPS.19*** "Cathodic Protection Survey". Separately protected sections of bare or ineffectively coated pipe (valve settings etc.) must be tested once per three (3) calendar years, not to exceed 39 months.

Each cathodic protection rectifier or other impressed current power source will be inspected six (6) times per calendar year, not to exceed 2 ½ months between inspections. Inspections will be documented on ***Form OPS.18*** "Rectifier/Bond Reading Log".

Each critical bond, each reverse current switch and each diode shall be inspected six times per calendar year, not to exceed 2 1/2 months between inspections. Each other interference bond (non-critical) shall be inspected at least once per calendar year, not to exceed 15 months between inspections. The results of the persist at or above (more negative) of this potential, further investigation shall be made and different criteria used if necessary.

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Any deficiencies will be corrected promptly. Remedial action will be taken prior to the next inspection period. When remedial actions taken are unsuccessful in returning the cathodic protection to an acceptable minimum level (-0.85V pipe to soil) an in-depth evaluation of the cathodic protection system will be conducted by the Senior Local Manager or designee in conjunction with a corrosion professional. The evaluation will include an assessment of the applicability of conducting a Close Interval Survey (CIS), Direct Current Voltage Gradient (DCVG) or other technology to assess the overall condition of the Cp System to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96. When sound engineering practices determines that the performance of a CIS or other technology is necessary, it shall be performed and documented so that the following conditions are addressed:

- Assess the overall effectiveness of the cathodic protection system.
- Provide baseline operating data.
- Locate areas of inadequate protection levels.
- Identify areas likely to be adversely affected by construction, stray currents, or other unusual environmental conditions.
- Select areas to be monitored periodically.

2.12.1.8 <u>ELECTRIC ISOLATION</u> [§195.575]

Each buried or submerged pipeline will be electrically isolated from other underground metallic structures. This is not required if the pipeline and other structures are electrically interconnected and cathodically protected as a single unit.

Insulating devices may consist of insulating flange assemblies or fabricated insulating joints. These devices should be properly rated for temperature, pressure and dielectric strength.

Electric insulating devices should be considered at locations such as those listed below:

1. At supporting pipe stanchions and other concrete foundations and structures where electrical contact would preclude effective cathodic protection.

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Electric insulating devices should be considered at locations such as those listed below:

1. At supporting pipe stanchions and other concrete foundations and structures where electrical contact would preclude effective cathodic protection.

2. At metallic curb boxes or valve enclosures.
3. Where a pipe enters a building through a metallic wall sleeve.
4. At river weights, pipeline anchors and metallic reinforcement in weight coatings.
5. At points of ownership change.
6. At connections to mainline pipeline systems.
7. Inlet and outlet pipeline of in line measuring and/or pressure regulating stations.
8. Pumping stations.
9. In stray current areas.
10. At other locations necessary to prevent electrical continuity with other metallic systems. (i.e. electrical conduit)

SHORTED CASINGS:

Whenever possible, pipelines should be installed uncased. However, for pipelines that are cased, should cathodic surveys indicate a shorted condition the condition should be handled in the following manner:

Shorted casings must have the short cleared, or the short's effects negated, within 6 months of discovery. The following actions will be taken, in order, as necessary:

1. Verify that the short exists. A casing may be deemed to be shorted when the pipe to soil reading of the casing and the pipe to soil reading of the carrier pipe reflect a reading within 50 mv of being the same. Additional testing such as continuity between the casing and carrier may be employed to verify that a short exists.
2. Determine course of action. (actions to be completed within 6 months)
3. Clear the short. If practical, this is always the solution of choice.
4. If it is impractical to clear the short, fill the casing/pipe interface with high dielectric filler.

5. If it is impractical to clear the short or to install filler, its location will be inspected at intervals that coincide with those required by for line patrolling as outlined in Section 2.12.1 of this manual. These inspections will be documented on ***Form OPS.19.***

2.12.1.9 TEST STATIONS AND TEST LEADS [§195.567]

Each pipeline will have sufficient test leads or other contact points for electrical measurement to determine the adequacy of cathodic protection.

Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive. After the test connection is made, any bared test lead wire or metallic area at the point of connection to the pipeline must be coated with an electric insulating material compatible with the pipe coating and the insulation of the wire. This coating will be inspected prior to covering the pipe.

Test leads must be maintained in a manner that will assure that electrical measurements can be taken in a manner that will confirm adequacy of the cathodic protection system.

2.12.1.10 INTERFERENCE CURRENTS [§195.575(e), 195.577]

Each foreign metallic structure crossing the pipeline system will be electrically inspected to detect any appreciable interference to the cathodic protection system. Should any stray currents or other interference be detected, the Senior Local Manager or designee will consult with a corrosion professional to ensure that the interference current is adequately mitigated.

Each impressed current or galvanic anode cathodic protection system will be designed and installed so as to minimize any adverse effects on adjacent existing underground metallic structures. Any indications of interference will be studied and appropriate mitigation measures taken within 6 months of discovery.

5. If it is impractical to clear the short or to install filler, its location will be inspected at intervals that coincide with those required by for line patrolling as outlined in Section 2.12.1 of this manual. These inspections will be documented on ***Form OPS.19.***

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2.12.2 INTERNAL CORROSION CONTROL [§195.579]

Prior to transporting hazardous liquid or Carbon Dioxide, the material will be tested to determine if it is corrosive. Any liquid found to be corrosive will not be transported until its corrosive effects on the pipeline can be investigated. When the investigation is complete, procedures will be developed and initiated to minimize the effects of corrosion. The investigation and development of procedures will be done in conjunction with a corrosion professional. These procedures must be followed while transporting the corrosive liquid. When the corrosive affects mitigation includes the use of inhibitors, they will be used in sufficient quantities to mitigate corrosion.
Whenever any pipe is removed from the pipeline for any reason, the internal surfaces must be inspected for evidence of corrosion. ***Form OPS.13*** "Pipe Inspection Report" shall be used for these inspections.

If internal corrosion is found, adjacent pipe must be investigated, both circumferentially and longitudinally to determine the extent of the internal corrosion. This pipe will be replaced to the extent required by Section 2.13.4 of this manual. After investigating the cause of this corrosion, steps must be taken to minimize any further internal corrosion.

2.12.2.1 <u>INTERNAL CORROSION MONITORING</u> [§195.579]

If corrosive liquid is being transported, injection of corrosion inhibiting equipment may be required. If so, effectiveness of the treatment program must be confirmed. This will include inspection of monitoring devices (corrosion coupons) at intervals not exceeding 7½ months, but at least twice each calendar year.

2.12.3 ATMOSPHERIC CORROSION CONTROL [§195.581, 195.583]

Each above ground portion of the pipeline system that is exposed to the atmosphere will be cleaned and coated with appropriate material to prevent atmospheric corrosion unless tests, investigations or experience has shown that without coating the corrosion will only be a light surface oxide or otherwise not affect the safe operation of the pipeline. Notwithstanding the above, the splash zone of offshore pipelines and the soil-to-air interface of onshore pipelines <u>must</u> be effectively coated.

Each portion of pipeline that is exposed to the atmosphere will be inspected every three years, not to exceed 39 months, to ensure that above ground piping is adequately protected from atmospheric corrosion. In the case of offshore pipelines, atmospheric corrosion inspections will be conducted once per calendar year, not to exceed 15 months and will include close scrutiny of splash zones, above water spans, and deck penetrations. The Senior Local Manager or designee will ensure that remedial action is taken whenever necessary to maintain adequate protection against atmospheric corrosion.

Inspections will be recorded on ***Form OPS.23.***

2.12.4 REMEDIAL MEASURES [§195.587, 195.585]

Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of corrosion must have a properly prepared surface and must be provided with an external protective coating as required in Section 2.13.1.5. Segments of pipe that requires repair for external corrosion must be cathodically protected.

Each segment of pipe with general corrosion and with a remaining wall thickness less than that required for the MOP of the pipeline, must be replaced or the operating pressure reduced to a level commensurate with the strength of the pipe based upon the remaining wall thickness. If the area of general corrosion is small, the corroded pipe may be repaired in lieu of replacement. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this evaluation.

The remaining pipe strength will be determined utilizing B31.G or RStreng methods and will be based on actual remaining wall thickness of the pipe.

2.13 ABANDONMENT OF FACILITIES [§195.402(c)(10)]

Pipeline abandonment shall be consistent with the requirements of DOT §195.402. Each abandonment shall be performed according to a written procedure that provides detailed steps to ensure that the segment is disconnected from all sources of combustible materials and is purged of those materials. If desired, an inert material may be left in the pipeline at low pressure. The ends of the abandoned sections will be sealed with steel plates, blind flanges, weld caps or other suitable methods.

Accurate records must be maintained on the location of all abandoned facilities Further, if the abandoned pipeline is offshore or onshore and crosses over, under or through a commercially navigable waterway, the abandonment must be reported to the Office of Pipeline Safety consistent with §195.59.

When a meter run or valve station is removed, and both the inlet and outlet risers are left standing, plugs, caps, or blind flanges shall be placed on the open ends of both pipes. Valves left connected to the removed facilities should be closed and tagged to avoid unnecessary pressure at the sealed ends.

resistance, attempt to correct by lubrication or other methods as required, depending on the type of valve being inspected. Note these facts in the "remarks" and "greased" columns.

5. Return the valve to its original position and re-install any locking devices.

6. Record all information on the appropriate forms for the system inspection and maintenance records.

2.12 CORROSION [§195.551]

All pipelines and breakout tanks must meet the requirements of Subparts ***D*** and ***F*** of 49 CFR 195. The procedures established in this manual fully satisfy the requirements of Subparts ***D*** and ***F***. All Company pipelines shall be cathodically protected. Supervisors that are responsible for the operations of pipelines will be thoroughly familiar with corrosion control requirements and the procedures to ensure that the requirements are met. Records demonstrating compliance with corrosion control requirements will be maintained according to 195.589.

2.12.1 EXTERNAL CORROSION CONTROL [§195.551]

This manual, in conjunction with the referenced volumes, establish the procedures to be used for the design, installation, operation and maintenance of cathodic protection systems. As stated in Section 2.2.3, these activities will be carried out by or under the direction of individuals qualified in pipeline corrosion control methods.

2.12.1.1 CATHODIC PROTECTION-GENERAL [§195.563(a),(b),(c),&(d)]

Except in unusual circumstances, all company pipelines will be cathodically protected. The following conditions will be used as a guide to determine the requirement for cathodic protection for a specific pipeline:

1. Each buried or submerged pipeline that is constructed, relocated, replaced or otherwise changed after the applicable dates shown in 196.401(c) must have cathodic protection applied within one year after construction or modification is complete.

2. Each buried or submerged pipeline which has been converted from a service not jurisdictional under Part 195 into a service that is jurisdictional must have cathodic protection if a) the pipeline has cathodic protection that in general meets requirements, or b) if the segment is relocated replaced or altered.

Abandoned facilities shall be recorded on ***Form OPS.13*** "Pipe Inspection Report" noting the date of abandonment and marked "Abandoned" in Remarks Section and becoming part of the system's permanent records.

2.14 CONVERSION TO SERVICE [§195.5]

If a pipeline that has operated in a service not subject to Part 195 or has been previously abandoned is to be reinstated as an operating pipeline subject to Part 195, it shall meet all the requirements of §195.5 before the conversion can occur. Records of the conversion are to be retained for the life of the pipeline and will include, at a minimum, those items identified in §195.5(c).and further discussed in Section 6 "Construction."

2.15 COMMUNICATIONS & CONTROL SYSTEM [§195.408]

Two modes of communications may be used on the pipeline. One mode is voice communications between stations or mobile units anywhere on the pipeline to be used in the transmission of information needed for the safe operation of the pipeline system. Specific uses of this voice communication system will be:

1) Receiving information from personnel, the public and public authorities of abnormal and emergency conditions and sending this information to personnel or government agencies for corrective action;
2) Conducting voice communications between the control center and the scene of abnormal and emergency operations.
3) Providing communication with police, fire and other public officials during emergency conditions including natural disasters.

All pipeline operations are equipped with this type of communication.

Another mode of communication is used in conjunction with a Supervisory Control and Data Acquisition System (SCADA) if equipped. This transmits operating data to a central location for monitoring. SCADA Systems may include Computational Pipeline Monitoring (CPM) for detection of leaks from the pipeline system. When equipped, the CPM system will be operated, maintained and tested to API 1130 specifications. Additionally, recordkeeping and training will be consistent with this publication. If this is used on the pipeline it will be described in Section 2A.15 of this manual.

2.16 PERSONNEL REVIEW [§195.403(c)(13)]

The work done by personnel will be evaluated periodically to determine the effectiveness of the procedures used in normal operating and maintenance. If deficiencies are found, corrective action will be taken. This review will be coordinated by the Senior Local Manager or designee and will be performed in conjunction with the annual O&M Manual review.