MARKWEST

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September 29, 2011

R.M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
8701 South Gessner, Suite 1110
Houston, TX 77074

RE: CPF 4-2011-1009M

Our response and amended procedures are enclosed for your review. Feel free to contact me if you need additional information on this matter.

Sincerely,

Bruce Gillick
Director of Environmental, Health & Safety
MarkWest Energy Partners, L.P.
(303) 925-9228

RE: CPF 4-2011-1009M

Item 1 – 192.16 *Customer Notification*

Although MarkWest does not have any customers on the ARKOMA pipeline, we have amended our OME. Please review the enclosed *Section 110 – Customer Notification*.

Item 2 – 192.613 *Continual Surveillance*

The OME has been revised. Please review the enclosed *Sections 401-404 - Surveillance*.

Item 3 – 192.736 *Compressor Stations: Gas Detection*

The OME has been revised. Please review the enclosed *Sections 505 – Compressor Station Gas Detection*.

Item 4 – 192.227 *Qualification of Welders*

The OME has been revised. Please review the enclosed *Sections 503 – Welding of Steel Pipelines*.

Item 5 – 192.243 *Nondestructive Testing*

The OME has been revised. Please review the enclosed *Sections 503 – Welding of Steel Pipelines*.

Item 6 – 192.227 *Internal Corrosion Control: Monitoring*

The OME has been revised. Please review the enclosed *Sections 405 – Corrosion Control (specifically page 108)*.

Objective
Notify customers that they are responsible for the sections of pipelines downstream of a custody transfer point.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR Part 192, Subpart A, §192.16

Requirement
Each new customer shall be notified once, in writing, within 90 days, the following items:

1. MarkWest – does not maintain the customer's buried piping.
2. If the customer's piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
3. The buried piping should be periodically---
   a. Inspected for leaks;
   b. Inspected or corrosion if the piping is metallic; and
   c. Repaired if any unsafe condition is discovered.
4. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.
5. The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customers buried piping.
6. MarkWest shall notify each customer not later than August 14, 1996 or 90 days after customer first receives gas at a particular location, whichever is later. However, mater meter systems may continuously post a general notice in prominent location frequented by customers.

A copy of the current notice in use and evidence that notices have been sent to customers within the previous 3 years shall be made available.

Responsibility
The Field Operations Manager or Field Technician is responsible for notifying new customers and maintaining the notice records.

Objective

Establish continual surveillance parameters and ensure remedial action is taken when anomalous conditions are identified. Any changes in class location, cathodic protection, leak history, third party excavation, pipeline exposures, and unusual operations/maintenance conditions will be reported to supervisors to ensure appropriate response.

Reference

Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR 192.613

Surveillance Records

The table below contains a summary of surveillance, review and reporting requirements that are detailed throughout this manual. Supervisors or designated alternates periodically review the status of the tasks to assure timely completion.

Inspection/Review	Sec.	Frequency	Form
Line Patrol and Leak Survey	402	See Table 402.1 (Section 402)	Line Patrol/Leakage Survey (Form 400-2)
Critical Crossings Leak Survey	402	Semi-annually (not to exceed 7.5 months)	Line Patrol/Leakage Survey (Form 400-2)
Aerial Patrol	403	Monthly if required	Line Patrol/Leakage Survey (Form 400-2)
Class Location Survey	404	As necessary	Population Density Survey (Form 400-9)
Valve Inspection and Maintenance	406	Annually (not to exceed 15 months)	Mainline Valve Inspection Report (Form 400-8)
Pressure Relief Device Inspection	407	Annually (not to exceed 15 months)	Pressure Relief Valve Inspection Report (Form 400-10)
CP Test Station Survey (pipe-to-soil readings)	405	Annually (not to exceed 15 months)	CP Test Station Survey (Form 400-3)
CP Rectifier Inspection	405	6 times/year (not to exceed 2.5 months)	Rectifier Inspection (Form 400-5)
External Corrosion (visual examination)	405	At time line is exposed	Form 300-1 Pipeline Maintenance, Repair & Inspection Report
Internal Corrosion (visual examination)	405	At time of cut	Form 300-1 Pipeline Maintenance, Repair & Inspection
Welder Qualification	503	Annually (not to exceed 15 months)	Letter to File
Annual Report to RRC and DOT	408	Annually	DOT Annual Report PHMSA 7 100.2-1
O&M Manual Update	101	Annually (not to exceed 15 months)	Letter to File
Emergency Response Plan & Call Notification Update	201	Annually (not to exceed 15 months)	Letter to File
Public Education & Damage Prevention Program Notifications	204 205	As documented in MarkWest Public Awareness Plan	Notification Letters; Newspaper Ads
Meeting w/ Local Fire and Police Officials	201	As documented in MarkWest Public Awareness Plan	Letter to File
Safety-Related Condition Report	203	If condition cannot be repaired, within 5 working days of identifying the condition but not later than 10 days after the discovery of the condition	Letter to DOT & RRC
DOT Incident Report	202	At time of incident	DOT Incident Report PHMSA 7100.1
Bell Hole Inspection Report	301	At time of repair	Form 300-1 Pipeline Maintenance, Repair & Inspection Report
Atmospheric Corrosion Visual Examination	405	Every 3 years	Atmospheric Corrosion Inspection – *Written Letter to File Documenting Inspection*

Objectives
Line patrols involve observations of surface conditions on and adjacent to the right-of-way, for indications of leaks, atmospheric corrosion, construction activity and other factors affecting the safety and operation of the pipeline. The patrol shall pay particular attention to construction activity and shall carefully observe road crossings which cannot be adequately observed by aerial patrol.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR 192.705, 192.706, 192.709, 192.935

Onshore Patrol Surveys
Onshore patrol surveys may be by ground, air or water. Observe surface conditions on and adjacent to pipeline rights-of-way for signs of construction or farming activities, leaks, erosion, line marker condition or any other factors that could affect public safety and operations. These patrol requirements, which include observations for leaks, satisfy Classes 1, 2 and 3 leakage survey requirements.

Leakage Surveys
The required frequency for leakage surveys varies for different class locations; see Table 402-1.

A transmission pipeline in a Class 3 or 4 area that operates at an MAOP below 30% SMYS and is located outside of an HCA must have the following:

- Semiannual leak surveys
- Quarterly leak surveys on cathodically protected and unprotected pipelines where electrical surveys are impractical

Conduct leakage surveys by walking, driving, flying or using a water vehicle. Note on the inspection report any construction activity, signs of erosion or sunken backfill and dead vegetation indicating leaks.

For pipelines that transport gas without an odor or odorant, use continuous gas sampling equipment when:

- Surveying Class 3 and 4 areas
- Conducting leak surveys at highway and railroad crossings

Results are recorded on the Line Patrol/Leakage Survey form (Form 400-2).

Critical Crossings Surveys
A line patrol and leak survey shall also be conducted at all critical road and railway crossings at intervals not exceeding 7 1/2 months, but at least twice each calendar year. Results are recorded on the Record of Line Patrol/Leakage Survey (Form 400-2).

Qualifications of Line Patrol Personnel
Personnel conducting line patrols and leak surveys will be qualified as per the MarkWest Operator Qualification Program.

Evidence of small leak locations that do not require immediate attention, possible changes in class locations, evidence of right-of-way encroachment and other areas that require further investigation and appropriate action by field personnel shall be reported as described below and addressed in an orderly fashion.

Records & Reports

The Line Patrol/Leakage Survey (Form 400-2) is used to record the results of the patrols and leak surveys and the semi-annual critical crossing surveys. The forms are to be completed and be kept on file in the MarkWest Oklahoma office. Retain the report on file for the life of the pipeline system covered by the patrol. In the event of a leak, the Form 300-1 Pipeline Maintenance, Repair & Inspection Report must also be completed in the same manner as above. If corrosion is found use Form 124.

Responsibility

The Operations Manager shall see that patrol activity is carried out on a timely basis, all patrol reports are carefully analyzed, and appropriate action is taken when patrolling results indicate recurring leaks, atmospheric corrosion, and/or severe deterioration along certain segments of the pipeline. MarkWest Pipeline Technicians will normally conduct the line surveys and leak patrols with help from other qualified Production, Maintenance or contract personnel as needed.

Notification of Leaks by the Public

All reports to the Company by the public of suspected leaks shall be investigated immediately and appropriate action taken. Where such suspected leaks are verified, appropriate public officials shall be notified immediately if any possible danger to the public exists. Written records of all such reports of suspected leaks shall be made and kept on file for the life of the facility. Such records shall contain the time and date of the report, name of the person reporting the suspected leak and all other relevant information, including action taken thereafter.

TABLE 402.1 - MINIMUM FREQUENCY REQUIREMENTS FOR PATROL AND LEAKAGE SURVEYS FOR ONSHORE PIPELINES

Class Location	Patrol Surveys[1]	Leakage Surveys	Highway and Railroad Patrol And Leakage Surveys[2]	
	All Natural Gas Transmission, Gathering and Non-Rural Gathering Pipelines	All Onshore Pipelines	Cased Crossing Mechanically Shorted and not Filled with Wax	Uncased Crossing and Cased Crossing Electrolytically Shorted, Filled with Wax or Voltage Difference >50mv Between Casing and Pipe
1 and 2	At least once each calendar year but not to exceed 15 months	At least once each calendar year but not to exceed 15 months	At least four times each calendar year but not to exceed 4-1/2 months	At least twice each calendar year but not to exceed 7-1/2 months
3 Unodorized, ≥ 30% SMYS	At least twice each calendar year but not to exceed 7-1/2 months	At least twice each calendar year but not to exceed 7-1/2 months[2]	At least six times each calendar year but not to exceed 2-1/2 months	At least four times each calendar year but not to exceed 4-1/2 months
3 Odorized, ≥ 30% SMYS		At least once each calendar year but not to exceed 15 months		
3 Odorized or Unodorized, <30% SMYS	At least twice each calendar year but not to exceed 7-1/2 months[4]	* Semi-annual survey or * Quarterly for unprotected pipe or cathodically protected pipe where electrical survey is impractical		
4 Odorized, ≥ 30% SMYS	At least four times each calendar year but not to exceed 4-1/2 months	At least once each calendar year but not to exceed 15 months		
4 Unodorized, ≥ 30% SMYS		At least four times each calendar year but not to exceed 4-1/2 months[3]		

Class Location	Patrol Surveys[1]	Leakage Surveys	Highway and Railroad Patrol And Leakage Surveys [2]	
4 Odorized or unodorized, <30% SMYS	At least four times each calendar year but not to exceed 4-1/2 months [4]	* Semi-annual survey or * Quarterly for unprotected pipe or cathodically protected pipe where electrical survey is impractical		

[1]Patrols may be performed using aircraft, motorized vehicle or on foot. Patrol schedules must be followed unless prohibited by a period of bad weather or acts of God.

[2]Continuous gas sampling equipment is required for unodorized gas.

[3]Continuous gas sampling equipment is required.

[4] If excavations near a pipeline are not monitored in an HCA segment or a Class 3 or 4 area, the segment shall be patrolled at bi-monthly intervals.

Objectives
An aerial patrol program is conducted to observe surface conditions on and adjacent to the right-of-way, for indications of leaks, construction activity and other factors affecting the safety and operation of the pipeline.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR Part 192.705

Scope and Frequency
Aerial patrols of the pipeline may be conducted as needed to provide effective surveillance of leaks and construction activity in support of the required annual line patrol and leak survey.

Procedures
The aerial patrol is conducted by a contract pilot who will fly the entire pipeline observing for indications of leaks, construction activity and other factors affecting the safety and operation of the pipeline. If conditions requiring immediate attention are observed, he will call the telephone number of the Operations Manager or the MarkWest Oklahoma office to report the problem.

Records & Reports
Results of patrols are recorded on the Line Patrol/Leakage Survey (Form 400-2) by the pilot and kept on file in the MarkWest Oklahoma office. Retain the report on file for the life of the pipeline system covered by the patrol.

Responsibility
The Operations Manager shall see that patrol activity is carried out on a timely basis, all patrol reports are carefully analyzed, and appropriate action is taken when patrolling results indicate recurring leaks, atmospheric corrosion, and/or severe deterioration along certain segments of the pipeline.

Objectives
Class location along a pipeline must be used to determine the required wall thickness of a pipeline for a given operating pressure. The objective of class location surveys is to determine and maintain records of the class location of any segment of a gas transmission steel pipeline operating at hoop stress in excess of 20% of the material minimum yield strength.

1. Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR Part 192, Subpart A, §192.5;
Subpart L, §192.609, §192.611 and §192.613

Scope and Frequency
The pipeline will be surveyed annually to determine if any change in population density indicates a change in class location and reported as noted below. Any changes to population density that warrant immediate attention will be addressed prior to the annual review. If changes in class location indicate a need for re-qualification or retesting, the procedures outlined in §192.611 shall be followed.

Procedures
The surveys will be conducted to identify new and existing buildings intended for human occupancy within 220 yards on either side of the pipeline. Additional development will be reported to the *MarkWest* Manager as noted below. The reports will be reviewed to determine the need for detailed investigation of population density using special surveys, aerial photographs or actual house counts. Whenever an increase in population density indicates a possible change in class location for a segment of pipeline, a study shall be immediately conducted as described in §192.609 & §192.611.

A sliding one-mile scale shall be used to determine the number of residences designed for human occupancy 220 yards adjacent to the pipeline centerline.

Records & Reports
The Class Location Survey (Form 400-9) is used to record the results of the class location surveys. The form is to be completed by the patrol crew and returned to the Field Operations Manager for approval. Copies of past patrols will be kept on file in the DOT Files in the McAlester, Oklahoma office. Reports will be retained on file for the life of the pipeline system.

Responsibility
The Field Operations Manager shall see that the class location survey

TABLE 404-1 CLASS LOCATION AREA

CLASS 1	a. 10 or fewer buildings within the class location unit b. All offshore pipelines
CLASS 2	MORE THAN 10 AND FEWER THAN 46 BUILDINGS WITHIN THE CLASS LOCATION UNIT
CLASS 3	a. 46 or more buildings within the class location unit b. An area where the pipeline lies within 300 feet of either a building or a small, well-defined outside area (such as a playground, recreation area or other place of public assembly) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. in this case, the class 3 area ends 300 feet on either side of the qualifying commercial building or outside area
CLASS 4	Buildings with four or more stories above ground are prevalent within the class location unit. This includes parking garages. The majority of the structures in the class location unit must be four or more stories for the area to be class 4

Objectives
This document prescribes requirements for protecting buried or submerged metallic pipelines from external corrosion in conformance with applicable codes, accepted industry practices and company specifications. External corrosion control procedures, including those for designing, installing, operating and maintaining cathodic protection systems must be carried out by or under the direction of a person qualified in pipeline corrosion control methods.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR Part 192, Subpart I, 192.451-455, 192.459-485 and 192.491

General Corrosion Control
Each time any portion of a buried pipeline is exposed, the exposed portion will be examined for the evidence of external corrosion or coating deterioration. If external corrosion is found, requiring corrective action, the pipe will be investigated 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. Potentials will be measured at the soil/pipe interface if coating is damaged. All information is to be recorded on Form 300-1 Pipeline Maintenance, Repair & Inspection Report and retained for as long as the pipeline remains in service.

The corrosion control of external surfaces of buried and submerged structures involves a variety of techniques. They include the use of coating, electrical insulation and cathodic protection devices. All new buried or submerged pipelines and all new pipe replacements in existing lines shall have a cathodic protection system designed to protect the pipeline in its entirety. These facilities shall be installed and placed in operation not later than one year after completion of construction.

Each bare pipeline that is not cathodically protected shall be electrically inspected, at intervals not exceeding three (3) years, and leak records studied to determine if additional protection is needed. If active corrosion is found, it shall be cathodically protected and mitigated

Attachment 1 includes a discussion of galvanic corrosion. Attachment 2 includes a discussion of the effects of soil types on corrosion. Attachments 3 and 4 include criteria for grading Close Interval and Direct Current Voltage Gradient Surveys.

Criteria for Cathodic Protection
This procedure specifies criteria (applied individually or collectively) to provide adequate cathodic protection for all regulated facilities. No single criterion has proven satisfactory or practical to evaluate cathodic protection effectiveness for all conditions. Special cases may require using criteria different from those provided in this procedure. Consult with the area corrosion representative for assistance with applications that may require other monitoring criteria.

Each cathodic protection system must provide a level of protection that complies with one or more of the following criteria:

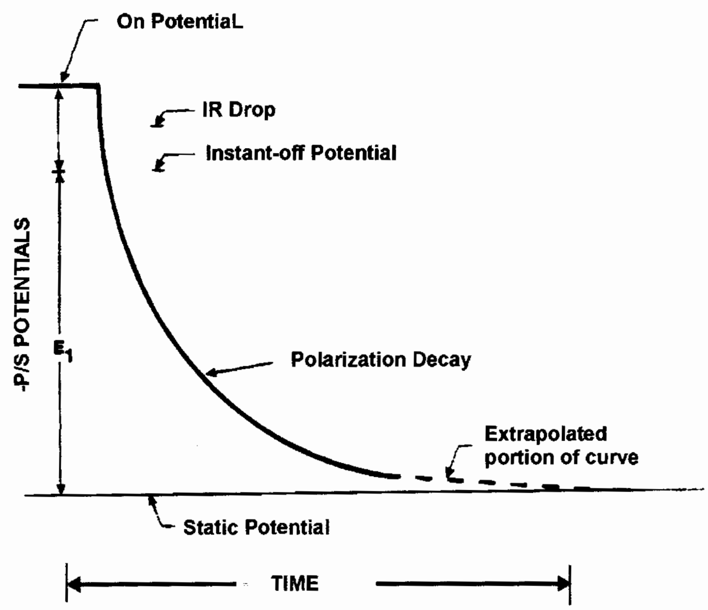
a) A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode

contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement.

b) A negative polarized potential of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.

c) A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.

d) Or meet or exceed the minimum criteria set forth in "Criteria for Cathodic Protection" or the most current edition of the National Association of Corrosion Engineers (NACE) Standard RPO169-96.



E_1 = Polarization decay potential shift as described in DOT's Appendix D, paragraph A(3) of Subpart I.

External Corrosion Design Considerations

Structure design should include, but not be limited to, corrosion control considerations and cathodic protection current requirements. Electrically isolate the pipeline from all the following points except where: the pipeline is electrically interconnected with a structure and both are cathodically protected as a single unit or where the pipeline is intentionally bonded to mitigate interference currents:

- Producer, distributor and other mechanically interconnected pipelines at changes in ownership
- Metallic casings and wall sleeves
- Metal buildings and foundation steel
- River weights
- Valve enclosures (metallic buried valve boxes)
- Pipeline bridges

- Other foreign metallic structures
- Anywhere electrical isolation is required to facilitate applying cathodic protection

Note: Avoid installing insulating devices in areas containing a combustible or explosive atmosphere without taking precautions to prevent arcing.

Consider the following when designing for external corrosion:

- Induced A.C. current while operating in power line rights-of-way
- Shielding
- Other foreign cathodic protection systems near the facility
- Protect pipelines and insulating devices from fault currents and lightning with grounding anodes and fault current mitigation devices such as solid state surge suppressors

Test Stations and Other Contact Points

Provide sufficient test stations or other contact points for electrical measurements to determine if cathodic protection is adequate. Test points include test leads, valves, taps, meters, risers and other aboveground piping and should generally be no more than one mile apart. Install corrosion control test leads at:

- Pipe casings
- Foreign metallic structure crossings, if practical
- Buried insulating joints (install insulating joints above ground when practical)

Consider these factors when selecting test point locations:

- Land use
- Accessibility
- Distance from other test points
- Population density
- Pipe coating condition and pipeline current demand
- Problem areas indicated by close interval survey data
- The need for and appropriate use of cathodic protection determining coupons and permanent reference electrodes

Test Stations

All facilities under cathodic protection will have a sufficient number of permanent test stations, or test points, to evaluate the adequacy of the cathodic protection system of the facility. Test stations are also useful for line locating purposes, and should be permanently displayed on the pipeline markers. As a general rule, test stations should be installed at approximately 1-mile intervals, and where reasonably accessed.

Test stations shall be installed on the pipeline at all cased crossings unless there is another method of contacting the pipe, such as a service tap or valve available nearby. EXCEPTION: If the casing is on a facility that is not required to be under cathodic protection, a test station may not be required as long as it is treated as a shorted casing for monitoring purposes.

There may be occasions where a test station is abandoned, removed, relocated or deemed unnecessary for annual monitoring purposes. Approval for this action is required from a MarkWest Oklahoma Corrosion Specialist. The approval will be documented using the approved MarkWest Oklahoma recordkeeping and retrieval system.

Test Leads
Each buried or submerged pipeline or segment of pipeline under cathodic protection must have electrical test leads for external corrosion control.

Each test lead wire will be connected to the facility and maintained in order to remain mechanically secure and electrically conductive. The connection will be made to minimize stress concentration on the facility. When installing test leads, the bare test lead wire and the facility will be recoated with an electrical insulating material compatible with the coating and wire insulation.

Where test leads have been damaged, or worn to the point where they are not longer serviceable, the leads shall be repaired or replaced before the next inspection cycle, unless determined to be unnecessary and approved for retirement.

a) Install test lead(s) at each cased road/crossing (test lead shall be at same side of crossing as casing vents). Isolating joints, Waterway crossings, galvanic anode installations, Stray-current areas, and Rectifier installations. Form 400-3, Test Station Report.

b) Install test lead(s) at foreign crossing(s) when the need has been verified by MarkWest Oklahoma personnel. Request a test lead on foreign lines only after need has been established. Company personnel may assist the foreign pipeline owner if their assistance is requested. Comply with all safety procedures.

c) Install test lead(s) at sufficient locations to facilitate cathodic protection testing. And maintain test lead wires to obtain electrical measurements.

d) Test lead wire sizes shall not be smaller than #12 TW insulated wire. Provide looping so backfilling will not stress or break the lead; also prevent lead from causing stress on pipe.

e) Use a 15-gram or less thermite cartridge to attach lead to the pipeline. Do not use worn or damaged thermite welders. Use protective gloves and safety glasses. Coat bared test lead wire and pipe with compatible pipe coating.

f) Use the exothermic welding process as the standard method to attach test leads to the pipe.

g) Perform ultrasonic testing on pipe prior to attaching any test lead (pipe wall thickness shall be ≥0.125-inch and the pipe shall have no detrimental surface or internal defects).

h) Separate multiple lead attachments by a minimum of 4-inches
i) Use Permabond™ or equivalent epoxy connections for wire connections to pipeline facilities where applicable
j) Attach each test lead wire to the pipeline in a manner that minimizes stress concentration on the pipe

k) Coat each test wire connection to the pipe with an electrical insulating material compatible with the pipe coating and the wiring insulation

Cathodic Protection Design
Consider the particular characteristics of the pipeline system segment to be protected, such as coating quality at new and old pipeline segments, casings, bonds, bridges, foreign structures, right-of-way availability, unusual electrolytes and previous operating experience. Follow these considerations when designing cathodic protection systems:

- Materials and installation practices shall conform to existing codes and National Electrical Manufacturers Association standards. Consider NACE Recommended Practices and applicable software programs for design guidance.
- Select and design the cathodic protection system for optimum economies of installation, maintenance and operation
- Deliver sufficient cathodic protection current to the structure to meet an applicable criterion for cathodic protection efficiency
- Minimize interference currents on neighboring structures
- Current Requirements

Field Survey Work
For all impressed current cathodic groundbed designs:

- Determine the foreign facility crossings within the projected influence of the designed cathodic protection facility
- Obtain accurate measurements of the proposed cathodic protection system hardware locations
- Conduct current requirement and interference testing when practical
- Verify accessibility to the proposed work site
- Verify AC power availability, voltage and phase
- Verify and document any existing/historical groundbed locations
- Review site for environmental considerations
- For deep anode groundbed designs, determine the geology of the strata at the deep anode location.
- For distributed and conventional impressed current groundbed designs and galvanic anode designs, determine the electrolyte resistivity for the proposed anode locations.

Reviewing Design and Construction Work
A qualified person shall review impressed current and galvanic anode groundbed designs. The review should include calculation accuracy an agreement with assumptions and empirical design parameters, conformance to MarkWest standards, drawings, specifications and applicable codes. All construction work designed for corrosion control systems shall be in conformance with the latest revisions of construction drawings, specifications and applicable codes.

Qualifications for Supervisors
The Pipeline Manager or his/her designee is responsible for all personnel performing cathodic protection tests, evaluating the results of such test data, and installing cathodic facilities to ensure an adequate and acceptable corrosion program is maintained on the pipeline system.

MarkWest must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under 49 CFR 192.605 for which they are responsible for insuring compliance.

Qualifications for Personnel

All personnel performing maintenance corrosion control procedures must be either qualified to perform the procedure or perform the work under the direction of a qualified person. These procedures relate to maintenance of cathodic protection and external corrosion mitigation systems on existing pipelines. All personnel performing tasks covered by the Office of Pipeline Safety (OPS) Operator Qualification Rule must be qualified under the MarkWest Hydrocarbon, Inc. Operator Qualification Plan as required in Subpart N of 49 CFR 192.805.

Personnel must have passed the written qualification program to perform work on the pipeline corrosion program. The qualification program identifies covered tasks, qualifies the individuals to perform the covered tasks, and maintains their qualification at regular intervals.

Qualified personnel will conduct the corrosion tests, inspections, perform repairs, and provide proper documentation. The person performing the work is responsible to ensure that only approved procedures and materials are used to inspect, test, or repair the facilities or coatings.

External Corrosion Control

49 CFR 192.455 requires submerged or buried pipelines to have coatings for external corrosion control. Likewise, it requires submerged or buried pipelines to have cathodic protection that is operational not later than one year after the pipeline is constructed, relocated, replaced or otherwise changed. The objective of MarkWest's corrosion control program is to provide corrosion control to external surfaces of buried and submerged pipelines and structures.

Coatings and Cathodic Protection

The following table lists pipelines coatings and/or Federal Regulation requiring cathodic protection.

Construction Begun After	**Pipeline Affected**	**Protection Required**
July 31, 1971	Interstate/Intrastate pipeline	Coating Cathodic
Construction Before	**Pipeline Affected**	**Protection Required**
August 1, 1971	Interstate/Intrastate pipelines that have an effective coating	Cathodic
August 1, 1971	Interstate/Intrastate pipelines that do not have an effective coating (bare)	Cathodic
[redacted]	Bare pipelines where electrical survey indicates active corrosion	Cathodic
[redacted]	Unprotected pipelines where electrical survey indicates active corrosion	Cathodic

Galvanic anode or rectifier systems are used for general cathodic protection for MarkWest systems. Design, installation, operation and maintenance of cathodic protection systems are carried out by or under the direction of a person qualified by experience and training in pipeline corrosion control methods.

Monitoring External Corrosion

Monitor external corrosion by electrical survey according to the following schedule:

Item	Description	Evaluation Frequency
Cathodically Protected Pipeline – annual monitoring practical	Protected sections	Once per year, with intervals not exceeding 15 months
Cathodically Protected Pipeline – annual monitoring impractical	Separately protected short sections of bare or ineffectively coated pipe	At least 10% of the sections (not in excess of 100 feet) must be surveyed on a sampling basis annually. Each year different test sections will be analyzed so that over 10 years the entire line will have been surveyed.
Unprotected Pipeline	Determine need to add cathodic protection in areas of active corrosion from analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment	Once every three calendar years, with intervals not exceeding 39 months
Rectifiers, Reverse Current Switches, Diodes, Interference Bond Whose Failure Would Jeopardize Structural Protection	Check performance of each device	At least six times per year, with intervals not exceeding 2½ months
Other Interference Bonds	Check performance	At least once each calendar year, with intervals not exceeding 15 months

External Protective Coatings

General

Each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is constructed, relocated, replaced or substantially altered after July 31, 1971.

Each converted segment must have an external coating for external corrosion control if:

- The segment has an external coating that substantially meets 192.461 before the pipeline is placed into service or
- Is a segment that is relocated, replaced or substantially altered

All underground metallic structures (piping, water piping, air piping, oil piping, etc.) must be installed with protective coatings (excluding ground rods). Only the coatings listed in Tables 1 through 4 of this procedure have been approved for use. Number designations for coatings and primers are important and should not be substituted. Coatings and repair materials are listed in Tables 1 and 2 by both their product name and generic description. In Table 1, the pipeline coatings are listed by their brand names that may be on company records and no longer available and the second column identifies the generic coating type. Table 2 is a guideline for compatible generic repair coatings for joining same or dissimilar coatings. Make the coating repair with a protective coating compatible with the original protective coating as detailed in the appropriate table in this procedure.

Coating material for external corrosion control will:

1. Be designed to mitigate corrosion of the buried or submerged pipeline;
2. Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

3. Be sufficiently ductile to resist cracking;
4. Have enough strength to resist damage due to handling and soil stress;
5. Support any supplemental cathodic protection; and
6. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
7. All external pipe coating will be inspected just prior to lowering the pipe into the ditch or submerging the pipe. Any coating damage discovered will be repaired before the pipe is lowered or submerged.

Special Applications

Coatings for special applications may not be listed in this procedure. Contact Engineering for information before using coatings not on this list.

Coating Application

Make all practical efforts to dry the pipe before applying coatings or primers. Never apply coatings when the steel surface is wet unless the coating is designed to be applied to wet surfaces as specified in the coating Manufacturer's application instructions. Review the recommended cleaning and surface preparation requirements for each coating before applying. All coatings have improved performance based on the quality of surface preparation. Abrasive grit blasting is the preferred surface preparation method. If abrasive grit blasting is not feasible, use methods such as hand tools or power equipment with abrasive disk pads, air driven needle scalers or non-woven abrasive pads to remove corrosion rust products, old coating products and to prepare the surface for coating.

Apply all protective coatings according to the manufacturer's specification. Allow time for the coating to sufficiently cure and inspect the coating prior to backfilling. Provide additional protection to the coating where needed during backfilling by using clean earth padding, rock shield or pipeline felt.

Above Grade Pipe Coatings

Buried pipe that extends above grade should be coated with an approved underground coating at least one foot above grade. Paint over the aboveground coating to match the paint color applied for atmospheric corrosion and to protect the below grade coating from ultraviolet rays from the sun.

Inspection

Visually inspect all protective coatings. Test coatings for holidays with an electronic detector. The necessary holiday detector voltage will vary with the type of coating and thickness. The application tables include guidance voltage for holiday detector settings. As a general rule, detector voltage setting should be 125 times the coating mil thickness. Example for 30 mil coating: 125 x 30 = 3,750 volts. Holiday detectors for higher voltage ranges are available with metal coils, metal brushes or conductive rubber wands for contact. Low voltage types using a wet sponge wand are available for small, irregular painted surfaces up to l0 mils thick (or on painted surfaces up to 20 mils thick with suitable wetting agent).

Operating Temperature Limitations

Some older coating systems, such as asphalt enamels, have test results that indicate serious coating damage at ≥110° F. Newer thin film powder epoxy coatings can perform with operating temperatures

equal to or greater than 200° F. Review the operating temperature range for the pipeline segment prior to selecting a repair coating from the appropriate tables in this procedure.

Coating Performance Considerations

Tape coatings do not perform well on large diameter pipelines or pipelines that experience high operating temperatures. Cold applied tapes tend to disbond and shield pipe from cathodic protection current. Hot applied tapes can be used on pipelines 16-inches or less in diameter with an operating temperature ≤ 120° F.

Use only the tapes listed in the tables. Do not substitute tape and primer numbers. Heat shrink materials generally do not perform well on large diameter pipelines and are limited to 12-inch and smaller pipelines. Heat shrink materials should be limited to low operating temperatures and small diameter pipelines and selectively used on transmission piping only after considering all alternative coating products available for the application. Heat shrink materials require preheating the pipe to temperatures that can damage the adjacent coating. Without preheating correctly, the heat shrink materials will not bond adequately to the pipeline.

Liquid epoxy product coatings provide excellent coating performance but require surface preparation to a near white cleanliness and 2 mils or more anchor pattern for best results. Prepare the surface by blasting with appropriate abrasive grit media to a white metal surface, use 80-grit abrasive sandpaper or hand power equipment with an 80-grit disk to roughen the surface to a white metal finish. Apply to a thickness specified by the Manufacturer and listed in the tables of this procedure. Correct mixing ratios are necessary for proper reaction. Apply by pouring, brushing, rolling, spraying or daubing as specified by the Manufacturer. Liquid epoxies specified in the tables have a wide range of operating temperature limitations and various cure times for cold or warm weather application.

TABLE 1 - PIPELINE COATING NAMES AND GENERIC SPECIFICATIONS

Pipeline Coatings	Generic Specification
Barretts (All designations) (no longer available)	Coal Tar Enamel
Bitumastic 70B (no longer available)	Coal Tar Enamel
Buton (Enjay Chemical Company coating no longer available)	Modified Butadiene-Styrene Copolymer
Dura Plate	High Solids Epoxy
Enamel "X" (no longer available)	Coal Tar Enamel
Fast Clad ER Epoxy	High Solids Epoxy
Flakeline (251 or 252)	Polyester Resin Epoxy
Gulf States #434 (no longer available)	Asphalt
Hevicote	Concrete over Hot Applied Asphalt Mastic Coating
Hot-Service Enamel (no longer available)	Coal Tar Enamel
Koppers Bitumastic No. 300M	Coal Tar Epoxy
Koppers (All other designations)	Coal Tar Enamel
Lilly or Pipeclad (All designations)	Fusion Bonded Epoxy (thin film powder coatings)
Lilly 20/40 (Topcoat Abrasive Coating)	Thermoset Polymer
Lions (All designations and no longer available)	Asphalt Enamels
Nap-Gard (All designations)	Fusion Bonded Epoxy (thin film powder coatings)
P/W	Painted with Coal Tar Enamel & Felt Wrap
PP&F	Coal Tar Enamel (Primer, Paint & Felt)
Pittsburg (All designations)	Coal Tar Enamel
Plicoflex Tape	Tape
Polyguard Tape	Tape
Polyken Tape	Tape
Powercrete (Overcoat Abrasive Coating)	Epoxy Based Polymer Concrete
Powercrete J (Joint Coating with or without FBE)	Epoxy Based Polymer Concrete
Pritel 20/40	Extruded Polyethylene
Protegol UT Coating	Polyurethane/Tar
Regular Enamel	Coal Tar Enamel
Reilly 230A	Coal Tar Enamel
TGF	Coal Tar Enamel with Glass and Felt Wrap
TGP	Coal Tar Enamel with Glass & Perforated Polyethylene Tape

Scotchkote (3M Company All designations)	Fusion Bonded Epoxy
Servi-Wrap	Tape
SP-2888	High Solids Epoxy
Tapecoat	Tape
Valpipe 100	Urethane
Whitcolite A-303E (no longer available)	Asphalt Enamel
X-Tru Coat	Extruded Polyethylene
XXH Enamel (no longer available)	Coal Tar Enamel

If the coating name or generic specification cannot be determined or is not listed in this table, contact Engineering for assistance.

TABLE 2 - COMPATIBLE REPAIR COATINGS FOR JOINING SAME OR DISSIMILAR COATINGS

Original Coating	Joining Coating	Repair Coatings (in order of preference)
Coal Tar Enamel	Coal Tar Enamel	1) Epoxy, 2) Heat Shrink Material[d], 3) Tape[c]
Coal Tar Enamel	Fusion Bond Epoxy	1) Epoxy, 2) Heat Shrink Material [d] Tape[c]
Coal Tar Enamel	Extruded Polyethylene[a]	1) Powercrete JP, 2) Heat Shrink Material[d], 2) Tape[c]
Coal Tar Enamel	Asphalt Enamel	1) Epoxy, 2) Tape[c]
Coal Tar Enamel	Polyester Epoxy	1) Epoxy, 2) Heat Shrink Material[d], 3) Tape[c]
Coal Tar Enamel	Tape[c]	1) Tape[c] 2) Epoxy
Coal Tar Enamel	Polyurethane/Tar	1) Epoxy, 2) Heat Shrink Material, 3) Tape[c]
Asphalt Enamel	Fusion Bond Epoxy	1) Epoxy, 2) Heat Shrink Material[d] , 3)Tape[c]
Asphalt Enamel	Extruded Polyethylene[a]	1) Powercrete JP, 2) Tape[c]
Asphalt Enamel	Polyester Epoxy	1) Epoxy, 2) Tape[c]
Asphalt Enamel	Tape[c]	1) Epoxy, 2) Tape[c]
Asphalt Enamel	Polyurethane/Tar	1) Epoxy, 2) Tape[c]
Fusion Bond Epoxy	Fusion Bond Epoxy	Pinholes: 1) Epoxy, 2) Heat Stick, 3) Powercrete J Large Repairs: 1) Epoxy
Fusion Bond Epoxy	Extruded Polyethylene[a]	1)Powercrete JP, 2) Tape[c]
Fusion Bond Epoxy	Polyester Epoxy	1) Epoxy, 2) Polyester Epoxy[b], 3) Tape[c], 4) Powercrete J
Fusion Bond Epoxy	Tape[c]	1) Epoxy, 2) Tape[c]
Fusion Bond Epoxy	Polyurethane/Tar	1) Epoxy, 2) Heat-Shrink Material[d], 2) Tape[c]
Extruded Polyethylene[a]	Extruded Polyethylene[a]	1) Powercrete JP, 2) Tape[c]
Extruded Polyethylene[a]	Polyester Epoxy	1) Epoxy, 2) Powercrete JP, 3) Tape[c]
Extruded Polyethylene[a]	Tape[c]	1) Powercrete JP, 2) Tape[c]
Extruded Polyethylene[a]	Polyurethane/Tar	1)Powercrete JP, 2) Epoxy, 2) Tape[c]
Tape	Tape	1) Tape[c]

Footnotes:

[a] Includes coatings such as Pritec and X-Tru-Coat. Does not include polyethylene-backing tapes.

[b] Can be used to overlap original coating during field application of polyester epoxy.

[c] Tapes are easily damaged by impact. Use a protective wrap in soil-stress areas and when backfill contains rock or other material that can cut through the tape. Hot applied tape is limited to repairing pipe 16-inches or less in diameter, operating at temperatures less than 120° F.

[d] Limit heat-shrink material to 12-inches or less diameter pipelines.

TABLE 3 - COATING REPAIR MATERIAL FOR UNDERWATER STRUCTURES

For use on underwater structures of limited surface areas, wet pipe surfaces and splash zones

Manufacturer	Coating Name	Generic Type	Footnotes	Remarks
Tyco Adhesives - Power Lone Star	Powerdur	Liquid epoxy polymer	a	For repairs in splash zones or pipelines subjected to wet surfaces from condensation. Minimum surface preparation aboveground using hand power tools such as needle guns or grinders, water blasting or dry abrasive blasting to yield a firm, granular surface free of loose contamination. Apply with putty knives or straight edge spreaders underwater or aboveground to yield 40 mils film thickness. Cures to a hard film within 14 hrs. at ambient temperatures. Cures underwater with retarded cure time.
Royston Laboratories, Inc.	Royston Wet-Set B-822	Epoxy-Amide	a	Smear on surface by hand. Pot life is 1 hr. below 100° F. Cure time is 2 hrs. @ 80° F, 6 hrs. @ 60° F. Thickness ⅛" to ¼" required. Cures underwater with retarded cure time.
Ameron International	Devoe Devclad 182 Splash Zone Barrier Coating	100% solids epoxy	a, b	Smear on surface by hand. Pot life is 1 hr. at 77° F. Cure time is relative to thickness and moisture conditions. Minimum time 30 minutes. Thickness ⅛" to ¼" required. Cures underwater with retarded cure time.
International Protective Coatings	Interzone® 1000 Glass Flake Epoxy	92% glass flake solids, high build epoxy. Primers Intergard 269 or 982 recommended.		All surfaces to be coated should be clean, dry and free from contamination. Abrasive blast to SSPC-SP10, surface profile should be 3 to 4 mils. Airless spray equipment preferred. Aggregate can be added for non-slip applications on decks. Cure time (touch dry) 5 hrs. @ 77° F, 30 minutes cure time for immersion underwater.
International Protective Coatings	Interzone® 954 Modified Epoxy	85% solids. Primers Intergard 269 or 982 recommended for underwater applications.		May be applied to reoxidized and slightly damp surfaces. All surfaces to be coated should be clean, dry and free from contamination. Abrasive blast to SSPC-SP6, surface profile should be 2 to 3 mils. Airless spray equipment preferred. Aggregate can be added for non-slip applications on decks. Cure time (touch dry) 4 hrs@ 77° F, 30 minutes cure time for immersion.

Table 3 Footnotes:

a. Abrasion grit blasted surface preparation recommended if practical.

b. In rough weather, apply a spiral wrap of polyethylene, glass fiber, burlap, cheesecloth or similar material over the freshly applied coating to help hold the coating during the initial curing operation.

TABLE 4 - APPROVED REPAIR COATINGS FOR UNDERGROUND STRUCTURES

Generic Type	Manufacturer	Coating Name	Max. Serv. Temp.	Holiday Detector Voltage	Foot- notes	Remarks
Epoxy	Denso North America	Protal 7200 Fast Cure Epoxy - Brush Grade Protal 7250 Fast Cure Epoxy - Spray Grade	185° F	2000V	a, b, d, e	Two-part mixture. High build fast cure liquid epoxy brush applied in one coat to 25 to 30 mils dry film thickness (D.F.T.) High moisture tolerance. Surface temperatures below 50° F must be preheated. Pot life @77° F is 6 minutes; handling time @77° F is 60 minutes. Interfaces and bonds to coal tar enamels and asphalts. Shelf life is 24 months.
Epoxy	Denso North America	Protal 7125 Epoxy Fast Cure Low Temperature	150° F	2000V	a, b, d, e	Specifically designed for cold pipe surface and ambient conditions. Fast cures at -4° F. Two-part mixture. One coat brush, roller or spray application to 25 to 30 mils D.F.T. Cure time varies from 7 minutes to 120 minutes with various substrate and ambient temperatures. Trace amount of styrene in product limit bonding strength to coal tar asphalt enamels. Shelf life is 6 mos.
Epoxy Based Polymer Concrete	Tyco Power Lone Star	Powercrete J-Fast Cure	130° F	125V/ mil	a, b, e	Two-part epoxy applied at temperatures as low as 40° F without requiring heat during the application and cure. Apply using hot airless equipment or manual application. Yellow in color. Minimum 20 to 25 mils D.F.T. Bonds well to coal tar and asphalt enamels.
Epoxy Based Polymer Concrete	Tyco Power Lone Star	Powercrete J	130° F	4000V	a, b, e	Coating can be used as a joint coating or also as a repair or joint coating for Powercrete applications. Coating should be applied in two 15-mil coats at least 20 minutes apart to achieve a D.F.T of 30 mils. Bonds well to coal tar and asphalt enamels. Preheat if pipe temperature is ≤ 50° F.
Polyester Epoxy	Ceilcote Co.	Flakeline 251 (Spray) Flakeline 252	250° F	4000V	a, b,	Use primer P-370 for immersion service or if over 8-hr. time lag following surface preparation. Shelf life is 6 mos. Spray formulation requires special

TABLE 4 - APPROVED REPAIR COATINGS FOR UNDERGROUND STRUCTURES

Generic Type	Manufacturer	Coating Name	Max. Serv. Temp.	Holiday Detector Voltage	Foot- notes	Remarks
		(Brush)				spray equipment. Pot life is 35 minutes @ 70° F. Apply 2 to 3 coats to obtain 35 to 40 mils D.F.T. Cure time is 4 to 48 hrs. Requires grit blasting to white finish and 3 to 4 mil surface profile. Contains substantial amounts of styrene - does not bond to coal tar and asphalt enamels. Do not apply when pipe temperature is below 50° F or over 110° F.
Epoxy	3M Company	Scotchkote #323 Brush and Spray	230° F	125V/mil	a, b, d, e	For repair to all fusion bond epoxy coatings, bare girth welds or pipe rehabilitation projects. Application to 45 mils D.F.T. in one application using cartridge, brush, roller or plural component spray equipment. Dry to handle time 2 hours - 39 minutes @ 75° F. Preheat pipe if below 50° F. Shelf life is 18 mos.
Epoxy	Dupont Nap-Gard	NAP-GARD Patch Compound #7-1847	180° F	125V/mil	a, b, e	For repair to all fusion bond epoxy coatings, field coating girth welds and wet pipe surfaces. Rough surface with 80 or 100-grit sandpaper or power disk and brush apply one coat at 25 mils thickness by trowel, knife, etc. Pot life 60 minutes @ 77° F, cure time 5 hours to handle.
Epoxy	Jotun Powder Coatings	Valspar Fast Cure Epoxy Patching Compound, Grey #46F640.	200° F		a, b, d, e	For small coating repair and at test lead/rectifier terminal connections to pipe. Clean area to bright metal with 80-grit sandpaper or other means. Cartridge – Squeeze out desired amount near point of patch location. Mix well with stiff spatula or knife. Allow the patch to heat to the same temperature as the pipe. Spread the patch out to the desired thickness.
Epoxy Heat Stick	3M Company	Heat Stick #206P and 226P	250° F	125V/mil	b	Single component stick applied with heat for pinhole repairs on all fusion bond epoxy coatings. Roughen surface and preheat pipe sufficiently to

TABLE 4 - APPROVED REPAIR COATINGS FOR UNDERGROUND STRUCTURES

Generic Type	Manufacturer	Coating Name	Max. Serv. Temp.	Holiday Detector Voltage	Foot- notes	Remarks
						melt stick on contact. Apply heat until patch is smooth and glossy. Apply thickness of 25 mils.
Epoxy Heat Stick	Dupont Nap-Gard	Heat Stick #7-1631S Heat Stick #7-1677	250° F	125V/mil	b	Single component stick applied with heat for pinhole repairs on all fusion bond epoxy coatings. Roughen surface, preheat pipe sufficiently to melt stick. Apply heat until patch is smooth and glossy to 25 mils thick.
Epoxy/ Butyl Rubber	Tyco Power Lone Star	Powercrete JP	130° F	485 Volts per mil	a	Coating for girth welds on polyethylene and polypropylene coated pipe. Two-part application: 1) Apply the butyl rubber adhesive as a tape, overlapping the abraded mainline coating and the clean, bare steel. 2) Apply Powercrete J over the butyl rubber adhesive manually or spray to a minimum total D.F.T. of 25 to 30 mils.
Rubberized Mastic	Royston Laboratories Inc.	Roskote Mastic R28	250° F	125V/mil	a, c	For small repairs of coal tar and asphalt enamel coatings. Thin with toluene for application below 60° F. No primer needed. Clean area to bright metal with 80-grit sandpaper or other means. Stir thoroughly before using. Apply by brush, spray, spatula or rubber glove. Apply two coats, allowing the first coat to touch dry before applying second coat. Dries to touch in ½ hr, sufficient for backfilling in 1 ½ hrs. Shelf life is one year.
Heat Shrink Material	Canusa	KLON	150° F	10,000V	a, c	Wrapid sleeve material (105 mils) is shrunk onto pipe or weld joint with a special propane torch. Different sized sleeves are used for different sized pipes. Pipe must be preheated to 160° F before applying sleeve. **Limited to ≤12" pipe.** Compatible with PE, PP, FBE, PU, Coal Tar, Bitumen coatings. Not recommended for bends,

TABLE 4 - APPROVED REPAIR COATINGS FOR UNDERGROUND STRUCTURES

Generic Type	Manufacturer	Coating Name	Max. Serv. Temp.	Holiday Detector Voltage	Foot- notes	Remarks
						tees, fittings, etc.
Heat Shrink Material	Canusa	KLA Rapid Sleeve	125° F	10,000V	a, c	This sleeve is to be used where more soil stress conditions exist. Wrapid sleeve material is shrunk onto pipe or weld joint with a special propane torch. Different sized sleeves are used for different sized pipes. Pipe must be preheated to 150° F (hot to touch) before applying sleeve. Preferably should be used with Canusa C Primer. **Limited to ≤ 12" pipe and restricted operating temperatures**. Compatible with PE and FBE coatings. Not recommended for bends, tees, fittings, etc.

Table 4 Footnotes

a. Abrasion grit blasted surface preparation to NACE near white and 2 to 3 mil anchor pattern recommended if practical.

b. Roughen the exposed steel and coating around pinholes and small repair areas with Carborundum cloth or 80-grit sandpaper prior to application.

c. Use a protective wrap to protect tape from impact in soil-stress areas when backfill contains rock, caliche, hardened clay or other material that can cut through the tape.

d. Available in repair cartridges.

e. Use Mesa Corrosion Control Thermite Weld Caps (#Weld 50000) or similar product with epoxy products for pipeline test lead or rectifier connections. The Weld Cap is 3" x 3" square of 20 mil thick, high density polyethylene formed as an igloo. The dome of the cap is filled with epoxy and placed over the thermite weld. The cap is pressed down until epoxy fills the gap between the cap and the pipe surface. The igloo tunnel portion permits the lead wire to exit so the cap surface remains flush to the connected structure.

Examination Of Pipeline

At any time the pipeline is exposed or an atmospheric inspection performed, the pipeline will be inspected for condition of coating, evidence of corrosion, etc and remedial action taken in accordance with Integrity Mangement Procedures IM-009 *Pipe Repairs* and IM-012 *Examination of Underground Pipe and Associated Facilities.*

The following definitions apply:

Active Corrosion – Continuing corrosion, which could, unless controlled, result in a condition that is detrimental to public safety. Consideration should be given to those areas near people, homes, buildings, road crossings, and pipeline operating pressures.

Active Corrosion Zone – Includes any area where the public could be exposed to hazards caused by Active Corrosion. Including, but not limited to, pipe segments which have Active Corrosion and potentially impact a High Consequence Area.

Interference Bonds; Diodes and Reverse Current Switches

Each reverse current switch, diode and interference bond whose failure would jeopardize structure protection shall be checked electrically for proper performance six times each calendar year, with intervals not to exceed 2-1/2 months. Each remaining interference bond shall be checked at least once each calendar year, with intervals not to exceed 15 months. All electrical measurement data is to be recorded on Form 400-6, Critical Bond Report for evaluation.

Electrical Isolation; Interference Currents

Design

Adverse effects from interference currents shall be minimized by design, installation and, thereafter, as required. Electrical isolation is required between coated, cathodically protected facilities and bare, unprotected facilities. However, electrical isolation is not required when coated and bare facilities are cathodically protected as a single unit. Electrical isolation may be required to control the application of cathodic protection current. If an electrical isolation device is installed in an area where a combustible atmosphere is anticipated, precautions must be taken to prevent arcing across the device.

The Pipeline Manager or his/her designee shall collaborate with representatives of other companies in making joint tests and special studies of the common problems of corrosion and electrolysis prevention and control at locations where pipelines are adjacent to other structures. If the adjacent structure is a power line, the design must prevent the possibility of the pipeline carrying either unbalanced line currents or fault currents and the possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings, insulating joints, or pipe. Corrective measures in the form of cathodic protection, properly designed and located ground beds, sacrificial anodes, crossbeds, insulating couplings, and/or other devices are to be installed where indicated for the mutual protection of all the properties.

Complete Form 400-4, Corrosion Interference and Bond Data for each interference testing point (foreign line Crossing) and retain for the life of the pipeline being tested. This form is to be used at the first testing whether the bond is marked or not. When a pipeline shares the right of way with a high voltage electrical transmission line, either parallel or perpendicular, AC potentials should be taken at test stations during the normal monitoring cycle.

Electrical Isolation Measurements shall be made at insulated points and casings to determine the effectiveness of the insulation. Shorted flanges, unions, or other undesirable contact points shall be corrected as soon as possible. When a shorted casing is discovered, the Pipeline Manager or his/her designee shall initiate the appropriate action based on the following options:

a) Have the casing cleared of the short.
b) Have the casing filled with appropriate high dielectric casing filler.
c) Monitor the cased crossing with leak detection equipment at intervals not to exceed 7-1/2 months, but at least two (2) times each calendar year.

All data is to be recorded on *Form 400-11 Road Casing Evaluation* and forwarded to the Pipeline Manager or his/her designee, who shall maintain a record of shorted casings and of appropriate action taken.

Valve Boxes

Some other facilities that may require electrical isolation metallic valve boxes include:

a) Foreign owned facilities
b) Existing lateral taps where an electrical short is detrimental to the cathodic protection levels.
c) New installations of lateral taps
d) Flow Stations
e) Casings/Sleeves

Inspection and Tests

The effectiveness of electrical insulating devices will be determined when the Annual Potential Survey is completed. If the annual survey shows that the pipeline facility is adequately cathodically protected, electrical isolation will generally be considered to be adequate. Lateral taps will be inspected every three years not to exceed 39-months in conjunction with the atmospheric corrosion inspection. If the connection to the customer lateral is found to be shorted, and is determined to be detrimental to the pipeline, corrective actions will be taken by MarkWest Oklahoma.

Operation of Impressed Current Cathodic Protection Equipment

Immediately after placing an impressed current unit in operation following initial installation or any follow-up repair or adjustment, record a pipe-to-soil potential measurement at the nearest connected pipeline or structure. (Note: Particular care must be taken to assure the proper pipeline polarity is maintained.)

Each rectifier unit shall be adjusted and operated at proper levels that meet one of the criteria's outlined under "Objective" of this section. Records of all tests and adjustment shall be made on Form 400-5,Rectifier Report and forwarded to the Pipeline Manager or his/her designee to be maintained for the life of the facility.

Corrosion Maps/Records
Drawings and/or reports shall be prepared and submitted for each proposal for adding; revising, relocating, or replacing impressed current installations or galvanic anode beds. "AS CONSTRUCTED" drawings shall be submitted following completion of installations. Records of each analysis, check, demonstration, examination, inspection investigation, review, survey, and test must be retain for 5 years, except records for 192.459,192.465(a) and(b), and 192.477 must be retained for as long as the pipeline remains in service.

External Corrosion Monitoring
Inspections

a) At least once each calendar year, but not to exceed fifteen months, electrical measurements and inspections to determine the adequacy of existing corrosion control facilities shall be made and the results reported on Form 400-4, Corrosion Interference and Bond Data Report. These measurements shall include pipe-to-soil potentials at designated test stations and cased control facilities to insure proper operation. If adequate protection is not indicated, corrective steps shall be taken to restore the structure to the proper degree of protection.

b) Each electrical protection unit or other impressed current power source shall be inspected six times each calendar year, but not to exceed 2-1/2 months, to insure that it is operating. Report the results on Form 400-5, Rectifier Report. If the current output of a unit drops below that required for protection, the reason shall be determined and prompt remedial action taken. In the case of rectifiers and stray current interference/mitigation, the remedial action shall be performed before the next scheduled inspection, but not to exceed 2 ½ months (75 days).

c) Each interference bond whose failure would jeopardize structure protection shall be electrically checked for proper performance at least six times each calendar year, but not to exceed 2-1/2 months, and the results reported on Form 400-6, Critical Bond Report. Each other interference bond shall be checked at least once each calendar year, but not to exceed 15 months, and the results reported on Form 400-4, Corrosion Interference and Bond Data Report.

d) When a pipeline is uncovered for any reason, the Pipeline Manager or designee shall inspect the pipe and coating and report the results on Form 300-1, Pipeline Maintenance, Repair & Inspection Report

Documentation

a) All reporting shall be done on the Form 400-6, Critical Bond Report, Form 400-5, Rectifier Report, and Form 400-4, Corrosion Interference and Bond Data Report. All data on these forms shall be reviewed and retained by the Manager of Plant Operations or his/her designee.

b) The Pipeline Manager or his/her designee shall maintain a permanent file of all corrosion leak repairs. These records shall be used to establish the need for remedial measures when appropriate.

Internal Corrosion Control

MarkWest ensures corrosive gas is not being transported through continual monitoring of pipeline gas quality (gas chromatograph) which is required to meet transmission quality specifications. If corrosive gas is being transported in a pipeline, MarkWest personnel shall, at intervals not exceeding 7-1/2 months but at least twice each calendar year, examine coupons or monitoring equipment to determine the extent of any internal pipeline corrosion and document the findings on Form 400-7, Monthly Pipeline Corrosion Monitoring. Whenever any pipe is removed, a visual inspection will be made of the internal surface of the pipe for evidence of corrosion defects in the pipe, or foreign deposits, and documented on Form 300-1, Pipeline Maintenance, Repair & Inspection Report.

Atmospheric Corrosion Control

Definition

Atmospheric Corrosion is an area of extensive general corrosion, localized corrosion pitting or peeling scale on the steel surface that has damaged the pipe. Note: Conditions, which tend to be "cosmetic," do not affect the integrity of the steel substrate and do not qualify as atmospheric corrosion but may be considered for maintenance in the future.

General

Each pipeline or portion of the pipeline that is exposed to the atmosphere shall be cleaned and coated with suitable material for the prevention of atmospheric corrosion. The exceptions to this are those facilities where tests, investigations or experience has shown that corrosion will only be a light surface oxide, or the corrosion will not affect the safe operation of the pipeline before the next scheduled. All soil-to-air interfaces must be protected from atmospheric corrosion.

Monitoring

All aboveground facilities will be inspected for atmospheric corrosion at least once every three calendar years, not to exceed 39 months, for onshore facilities (*document findings in a letter to the file*).

Particular attention must be given during inspections to those areas at soil-to-air interfaces, under thermal insulation, under dis-bonded coatings, at pipe supports, at splash zones, at deck penetrations and in spans over water.

If atmospheric corrosion is found during an inspection, protection against further corrosion must be provided.

Road Casing

All cased road and railroad crossings shall be installed, tested, and maintained as discussed in this section.

Isolation Requirement for New Construction

Encased road and railroad crossings shall be isolated and/or tested as follows:

a) Electrical continuity tests shall be made at each casing installation during construction to assure that electrical isolation between the carrier pipe and the casing is effective. These tests shall be conducted both before and after backfilling. The electrical testing is to be accomplished using

an "Insulphone" or similar low voltage method. Welding machines are not to be used for this purpose. Shorted conditions must be corrected.

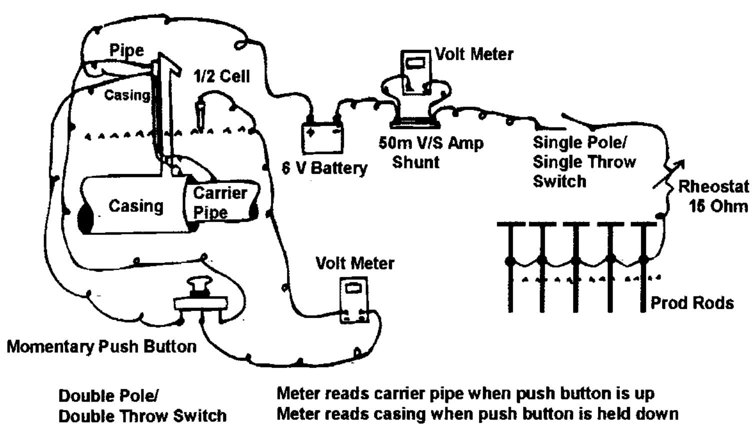
b) In order to verify continued electrical isolation, road and railroad crossing shall be checked at least once each calendar year, but with intervals not exceeding 15 months, during the routine potential survey. *Form 400-11-Road Casing Evaluation* shall be completed if a short is found.

Pipelines at many road and railroad crossings pass through casings. Casings can be either electrolytically or mechanically shorted. An electrolytic short is a pipe that is shorted to the casing through a non-metallic path, such as mud or water. It is generally not harmful since the electrolyte will distribute the current throughout the casing. A mechanical short is pipe that is shorted to the casing through a mechanical or direct path. Generally, a mechanical short will reduce the effectiveness of cathodic protection.

Test electrical isolation by comparing the casing-to-soil potentials to the matching pipe-to-soil potentials at least once each calendar year, not to exceed 15 months.

Difference	Electrical Isolation	Action
>50 millivolts	Yes	Inspect at required rate
≤50 millivolts	No	Test for type of short

The following schematic details the testing procedure to determine if a casing is shorted.



Apply current only long enough to take measurements. Adjust rheostats before current is applied.

	Pipe to Soil (V)	ΔP/S		Casing to Soil (V)	Δ P/S	I (A)	R (Ohms)
P/S_0			C/S_0				
P/S_1			C/S_1				
P/S_2			C/S_2				
P/S_3			C/S_3				
P/S_4			C/S_4				
P/S_5			C/S_5				
P/S_6			C/S_6				
						Average:	

$$R = \frac{\Delta P/S - \Delta C/S}{I}$$ Casing is shorted if average resistance is 0.08 ohms or less

Testing and Remedial Measures for Existing Road and Railroad Crossings.

a) Encased Road and Railroad Crossings Installed After August 1, 1971.

1. Test Facilities: It is mandatory that test wires for conducting electrical tests on both the carrier pipe and the casing be present at all road and railroad crossings. In lieu of test wires on the pipeline, exposed fittings, such as taps, valves, gauge fittings, etc., may be used as a contact to the pipe.

2. Evaluation: Structure-to-soil potentials of both the carrier pipe and the casing shall be taken and shall be compared in a first attempt to determine if the casing is shorted. A casing is considered shorted if potential difference between structure and casing is less than 100mV until further tests can be conducted to determine the status of the casing. If the status of a casing is unknown, it shall be treated as a shorted casing.

3. Follow-up: All casing found to be shorted shall have the short cleared or shall be filled with an acceptable casing filler material. If the short can only be cleared by moving the pipe or removing the casing, no work shall take place without approval from a MarkWest pipeline engineer.

4. Casings Exposed to Abnormal Conditions: In cases where the casing and/or carrier pipe inside a casing has been inspected and shows evidence of abnormal corrosion or it is known that the annulus between the casing and carrier pipe is exposed to mine or septic water, the casing ends are to be sealed and the casing filled with an acceptable casing filler material.

5. Pipe-to-Soil Potentials at Casing Ends: In any case, regardless of whether casing shorts are cleared or the shorted casing is filled with a casing filler, the pipe-to-soil potential of the carrier pipe up to the ends of the casing shall comply with at least one criterion for cathodic protection.

b) Encased Road and Railroad Crossings Installed Before August 1, 1971.

1. Test Facilities: In some cases, it can be shown that design or construction practices in force at the time a crossing was installed were such that the casing and carrier pipe are shorted. In such known situation, it will only be necessary to review and evaluate the local circumstances adjacent to the crossing and make a decision as to the manner of dealing with the shorted casing. The case may be dealt with by (1) clearing the short; (2) filling with an approved casing filler; or (3) if, under local circumstances, it is considered impractical to clear the short or fill the casing, monitoring the crossing with approved leakage detection equipment on a six month schedule until such time as circumstances change which would make it practical to clear the short or fill the casing.

In situations where it cannot be shown that a crossing was designed and/or installed in such a way as to result in an electrical short between the casing and carrier pipe, it is necessary

that the test wires be present for conducting electrical tests on both the carrier pipe and the casing. In lieu of test wires, exposed fittings, such as taps, valves, gauge lines, etc., may be used as a contact to the pipe if they exist in close proximity to the casing being tested.

2. Evaluation: Structure to soil potentials of both the carrier pipe and the casing shall be taken and shall be compared in a first attempt to determine if the casing is shorted. A casing is considered shorted if potential difference between structure and casing is less than 100mV until further tests can be conducted to determine the status of the casing.

3. Follow-up: Shorted casings or casings determined to be shorted by the testing procedure, which are in close proximity to homes, businesses, churches, schools, recreational areas, etc., or cross a major highway, are to either have the short cleared or are to be filled with an acceptable casing filler material. Priorities based on class location, operating pressures, highway importance, etc., should be established for completion of this work.

In all cases where a casing is shorted but it is determined that it is impractical to either clear the short or fill the casing with an acceptable casing filler, and if in the judgment of Company personnel the risk of corrosion is minimized by the then-existing conditions, including the location and condition of the pipe, the risk of overpressure, and environmental factors, the casings may be monitored with leak detection instruments at least four times a year (but at intervals not exceeding four and one-half months), until such time as: 1) it becomes practicable to either clear the short or fill the casing with casing filler; or 2) the conditions change which render the monitoring option inadequate to minimize the risk of corrosion.

4. Casings Exposed To Abnormal Conditions: In cases where the casing and/or carrier pipe inside a casing has been inspected and shows evidence of abnormal corrosion or it is known that the annulus between the casing and carrier pipe is exposed to mine to septic water, the casing ends are to be sealed and the casing filled with an acceptable casing filler material.

5. Status of Cathodic Protection at Casing Ends: Testing, evaluation and follow-up action on cased crossings installed before August 1, 1971, must comply with the requirements of this Policy and Procedure Letter. The status of cathodic protection on piping in the vicinity of the crossing outside the casing must be in compliance with the requirements of the entire pipeline. Such requirements being based on age, construction type, etc. Cathodic protection, if required, must meet the standards being applied to the particular pipeline, or section of pipeline.

Road Casing Shorts

Use this procedure to determine when a casing pipe is shorted to the carrier pipe.

a) Procedure

Testing for shorted casings with typical field-testing equipment is sometimes difficult and give results that are non-conclusive. When this happens, the following method is used to determine if the casing is shorted or not.

1. Attempt to depolarize the casing by using a temporary, variable DC power source, a temporary ground bed, and a connection to the casing. The positive lead wire from the power source is connected to the casing and the negative is connected to the ground bed. The ground bed should be at least 50 feet away from the casing. Activating the circuit will drive the potential of the casing in a positive direction.

2. Place a copper/copper-sulphate (CUSO) reference cell firmly in the ground as near as possible (an estimate) to the point where the casing ends. The CUSO reference cell is to remain at this location throughout the test procedure. Take and record readings on both the casing and the pipe.

3. Energize the system at a lower current level and take structure-to-soil readings on both the pipe and the casing. Increase the current output through three to five steps (up to about 5 amps) and take structure-to-soil readings on both the pipe and the casing at each current level.

4. A minimum of three measurements should be made with different current outputs. In some cases, up to five measurements may be necessary. Current output should vary for each test (up to 5 amps).

b) Results

1. If Casing Is Shorted

IF the casing is shorted, THEN (1) the casing-to-soil potential will shift in a positive direction, and (2) the pipe-to-soil potential will also shift in a positive direction, usually by about the same magnitude of the casing. As subsequent steps are taken, the pipe-to-soil potential will, to a great extent, track the positively shifting potentials of the casing.

2. If Casing Is Not Shorted

IF there is no short, THEN (1) the pipe-to-soil potential may shift in a positive direction by only a few millivolts, and (2) the casing-to-soil potential will shift dramatically. In some cases, the pipe-to-soil potential may shift in a negative direction by a few millivolts.

c) Actions and Reporting

Any remedial action taken must be documented. If the short is cleared or the casing is filled, monitoring with leakage detection equipment other than that required for normal patrolling will no longer be required. If the attempt to clear the short is unsuccessful and the casing cannot be filled as noted above, monitoring with a leakage detection instrument is required.

d) Exclusions

1. Casings that have been filled with an approved high dielectric casing filler material will not be considered as shorted for monitoring purposes, and will no longer be required to be tested annually.

2. If the casing is not shorted, no further action is required.

3. If the casing is on a facility that is not required to be under cathodic protection, it shall be considered to be shorted for monitoring purposes unless tests have been conducted showing otherwise.

4. Casings found to be shorted may be evaluated on their own merits based on safety and facility integrity, and suitable follow-up actions taken, if required. Follow-up actions may include:

Attachment 1

GALVANIC CORROSION

Galvanic corrosion results when two different metals are electrically connected and surrounded by the same electrolyte. The material with the highest electrochemical energy level, called the anode, would experience corrosion, and the other material, called the cathode, would not experience corrosion.

In the oil and gas industry, galvanic corrosion could be expected from connections between ferrous materials, such as steel and ductile iron, and copper, stainless steel or brass. In this corrosion cell the ferrous materials would corrode relative to the other materials. The following table lists the common types of steel piping and construction materials in order of galvanic activity:

Material	Potential (mV)	Activity
Magnesium	1.70	Most active, Anodic
Zinc	1.10	
Aluminum	1.10	
Steel	0.50 – 0.60	
Ductile iron	0.30 – 0.40	
Corroded steel	0.30 – 0.40	
Cast iron	0.10 – 0.20	
Copper	0.15 – 0.20	
Brass	0.15 – 0.20	
Stainless steel	0.10 – 0.20	Least active, Cathodic

This table indicates that, for two dissimilar metals being electrically connected, the one towards the most active end would be anodic or experience corrosion, and the one towards the least active end would be cathodic or not experience corrosion. For the corrosion to occur, both materials need to be in a common electrolyte and electrically connected. This is the fundamental concept of cathodic protection. Cathodic protection causes certain electrochemical reactions to occur on the structure that is being protected against corrosion. The protected structure becomes cathodic relative to the anode material. For sacrificial anode cathodic protection, this involves the use of magnesium, aluminum or zinc anodes on steel structure(s).

Attachment 2

SOIL EVALUATION

The measurement of soil resistivity has been used for years and accepted as the primary indicator of the corrosivity of soil. Soil resistivity is the reciprocal of conductivity; i.e., the lower the resistivity, the easier current will flow through the soil. Resistivity is a property of the bulk volume of soil and electrolytes.

It is generally agreed that the classification shown below reflects soil corrosivity:

Soil Resistivity (Ohm-cm)	Corrosivity
Below 500	Very Corrosive
500 to 1,000	Severely Corrosive
1,000 to 2,000	Moderately Corrosive
2,000 to 10,000	Mildly Corrosive
Above 10,000	Progressively Less Corrosive

The above table provides the expected external corrosion that may be experienced by a metallic structure in a soil of known resistivity. Deterioration can generally be expected to be rapid and relatively severe in soils with soil resistivities at or below 1,000 ohm-cm. This does not mean that severe corrosion will not occur in soils of higher resistivities; however, this does not generally occur. Not only is the resistivity useful in predicting relative corrosion rates, but also it is equally important to identify whether soil resistivity varies along a given route or at different depths.

Corrosivity of a particular soil is also affected by several other parameters, including chemicals present in the soil, moisture content, soil type and the presence of bacteria. Soil parameters typically are determined through laboratory analysis are:

Parameter	Discussion	Corrosivity
Soil Moisture	Free water	Corrosion increases with moisture
pH	Acid – Alkaline measurement	Corrosion increases with decreasing pH, usually lower than 6.5 to 7.5
Sulfide Concentration	Sulfides in the soil are indicative of the presence of sulfate-reducing bacteria (SRB). The presence of SRB's indicates oxygen deficient soils with a sulfate concentration that provides the SRB's food source.	[redacted]
Chloride Concentration	Chloride presence in the soil may have resulted from the present or historical presence of salt water.	Corrosion increases with increasing chloride concentration. Concentrations greater than 50 ppm should be considered more corrosive.

Attachment 3

CRITERIA FOR GRADING CLOSE INTERVAL SURVEYS

This document establishes guidelines and methodology for evaluating and grading cathodic protection close interval surveys. A close interval survey is a methodology to locate areas of inadequate cathodic protection that may exist between annual survey test points due to interference problems, poor coating, high resistance soils, low current density, and other similar problems.

Close Interval Surveys

A criteria close interval survey produces all three energy levels - the "static" or "native" potential, "instant off" potential with no protective current applied, and the "on" potential with the cathodic protection applied. It is an excellent tool that supplies all information needed to apply any cathodic protection criteria. The two procedures for applying cathodic protection are 1) the -850mV with protective current applied criteria and 2) the 100mV polarization shift criteria. A criteria close interval survey should be performed before applying the 100mV polarization criteria to a pipeline segment.

An "on/instant off" close interval survey can be performed where a criteria survey has been completed in the past and the "static" potentials have already been recorded. The "on/instant off" survey can then be used as a follow up survey to compare to the criteria survey "static" potentials when applying the 100mV criteria.

An "on" close interval survey produces the one energy level with cathodic protection current applied and cannot be used to apply the 100mV criteria. It is a good survey to determine coating conditions in between existing test leads, or possible coating damage where inadequate cathodic protection current density does not provide enough energy for regulatory compliance.

Grading the Survey

Each survey report will require and Action Plan and Closure Document. The Action Plan identifies work tasks to investigate anomalies and make system adjustments after the survey report has been reviewed. Action Plans are required to be completed within 30 days of receiving a graded close interval survey from a contractor. Any non-compliance regulatory anomalies found during the survey require remediation using IM/ O&M Procedures.

Where a coating anomaly or other anomaly is present, one would expect a lower coating resistance, resulting in a net positive shift in the "ON" and "INSTANT OFF" potentials registered. Where both of the potentials are more positive than -850mV, the pipeline would be considered unprotected at that particular point or area. This type of anomaly would require a significant increase in the output of the CP system to achieve protection. Unfortunately, this increase will likely result in overprotection in other areas, namely drain points. At these areas, the environment surrounding the pipeline becomes excessively alkaline, resulting in a further deterioration of the pipeline coating. To break this spiral, major anomalies are to be repaired, while leaving smaller anomalies to be protected by the CP system. In this way, equilibrium between CP and coating is restored and maintained. To facilitate this approach, all anomalies are categorized as follows:

Type I - Reduced IR factor; "ON" and "INSTANT OFF" potentials shifted in a positive direction over a short distance; both potentials more positive than -850mV; probable coating anomaly.

Type II - Reduced IR factor; "ON" and "INSTANT OFF" potentials shifted in a positive direction over a short distance; "ON" potential more negative than -850mV, "INSTANT OFF" potential more positive than -850mV; possible coating anomaly.

Type III - Reduced IR factor; "ON" and "INSTANT OFF" potentials shifted in a positive direction over a short distance; both potentials more negative than -850mV; possible coating anomaly.

Type IV - Step shift in potential; sudden "step-like" shift in "ON" potential in either positive or negative direction, with or without a similar shift in the "INSTANT OFF" potential; generally due to survey technique and not indicative of a coating anomaly.

Type V - Single spike in either or both potentials; generally due to poor soil contact, and not indicative of a coating anomaly.

Type VI - Long-term span effects, usually with a characteristic "saw-tooth" pattern in both potentials; generally caused by telluric or stray current effects, and not indicative of a coating anomaly.

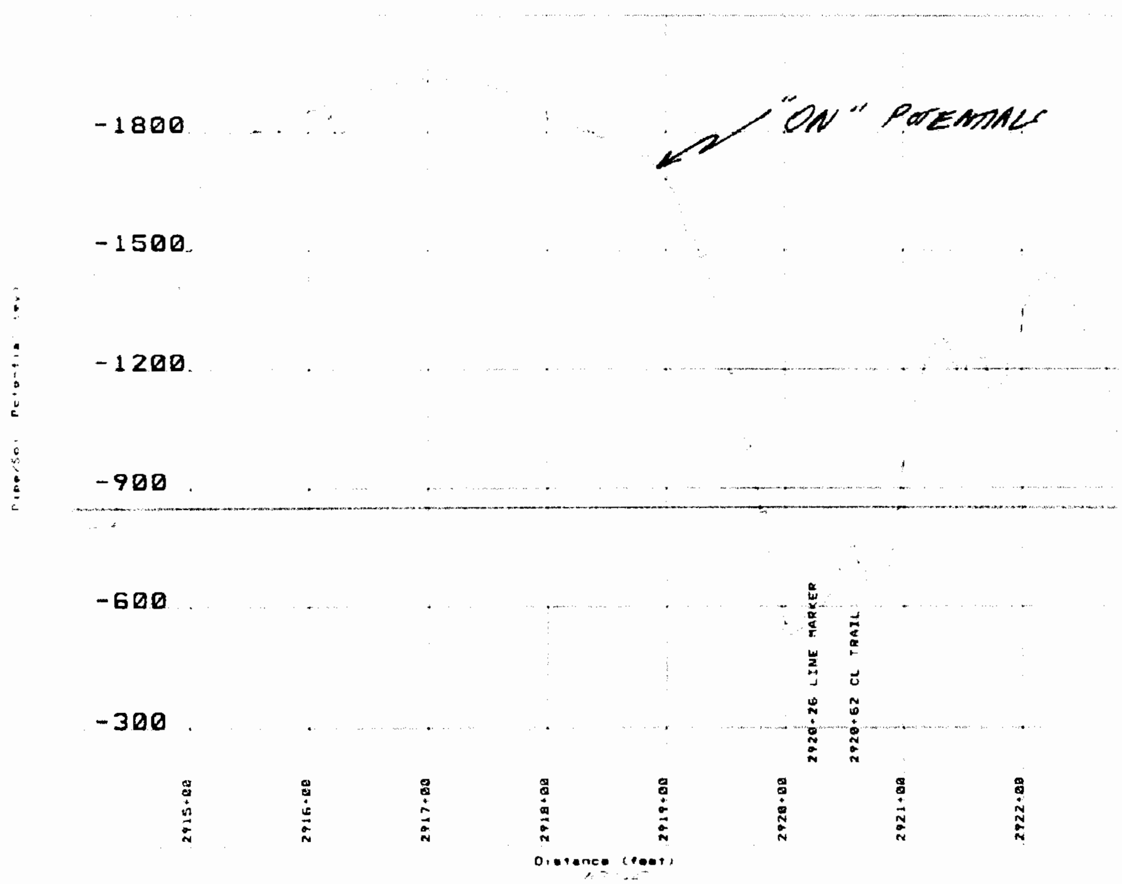
Of these anomalies, type I, II and III are worth further investigation. In general, Types I and II anomalies are recommended for additional DCVG survey to examine size and nature of the anomaly. Based upon the results of Types I and II and proximity to CP ground beds, Type III anomalies may also require further investigation.

Further criteria may be applied to the data collected during the survey upon completion of the CIS baseline and the CIS on/off survey; whereas, a delta shift criteria of 100mV between the baseline and instant off potential may be applied to sections where the pipeline is considered bare. This 100 mV shift criteria may demonstrate that there has been true polarization of the pipeline, thus allowing confidence that the pipeline is not undergoing active corrosion.

Where a coating defect or other anomaly is observed, a lower coating resistance would be expected, resulting in a positive shift in the potentials registered. Where the potential is more positive than –850 mV, the pipeline would be considered unprotected at that unique point or area. In the event that this is the case, the 100 mV shift criteria may be applied.

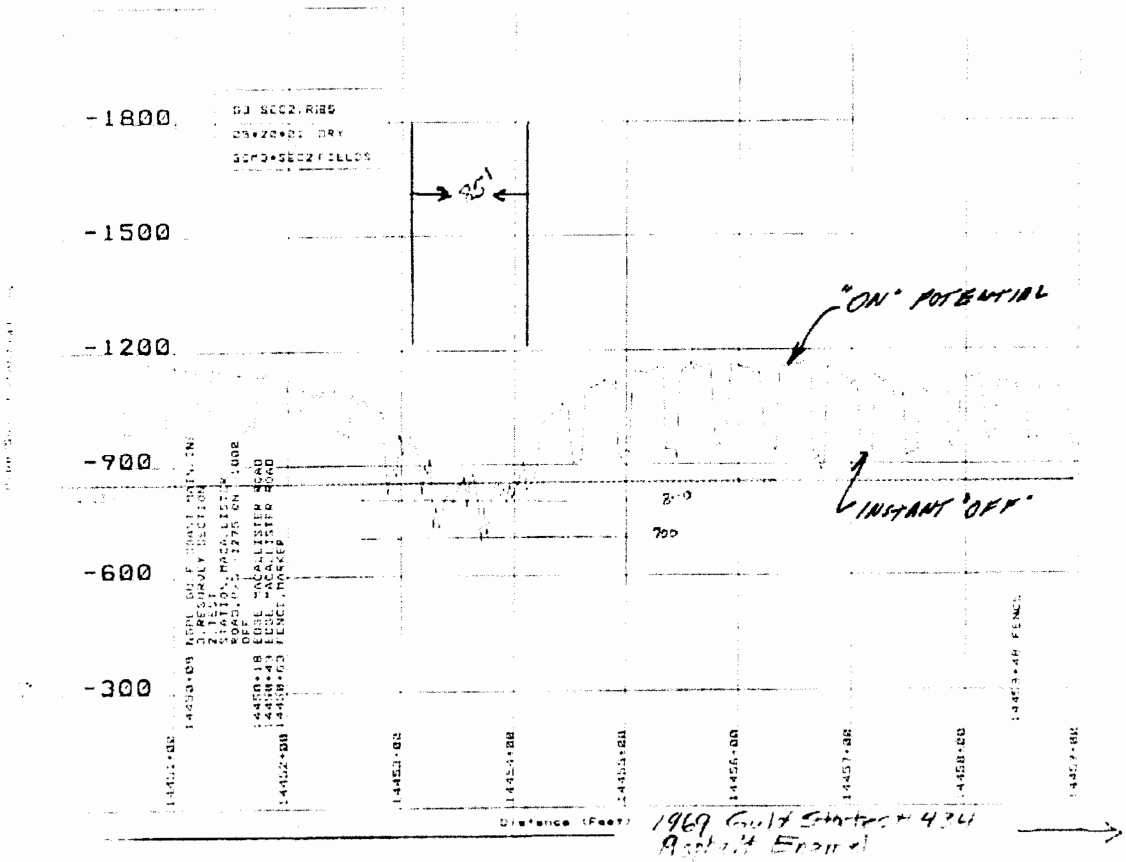
This type of anomaly requires a significant decrease in the output of the CP system to achieve protection. An increase in the output may over-protect other locations, namely drain points.

"On" Close Interval Survey Graph



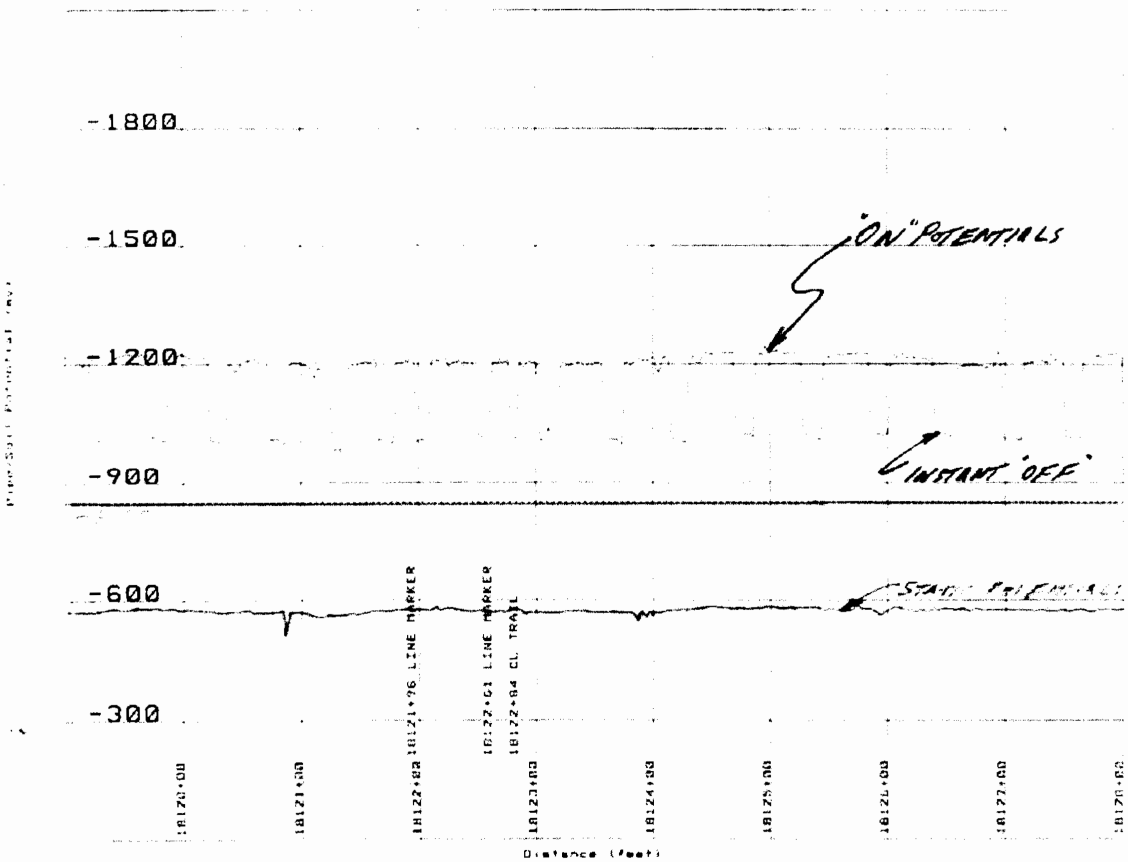
This example shows a typical "on" single line survey data collected with the cathodic protection current applied. The area where the pipe to soil potentials fall below the red -850mV potential line is an area requiring remedial action in accordance with the IM/ O&M Procedures. The area below the red line indicates coating damage and a possible anodic spot on the pipeline where corrosion could be occurring. This type of anomaly would typically require a bell-hole excavation to investigate the pipeline for corrosion and make repair to the damaged coating area. This is the type anomaly that would be identified on the Action Plan as requiring investigation and remediation.

"On/Off" Close Interval Survey Graph



This graph shows a typical "on/off" close interval survey. The saw toothed line shows the "on" period and the "instant off" period. The entire pipeline segment is within compliance with the exception of the 85' that is marked off and the saw toothed "on/off" potential line goes below the red -850mV line. The area below the red line will require remediation in accordance with the IM/ O&M Procedures. This area would typically be excavated to determine if metal loss exists and to repair the damaged coating. This is the type anomaly that would be identified on the Action Plan as requiring investigation and remediation.

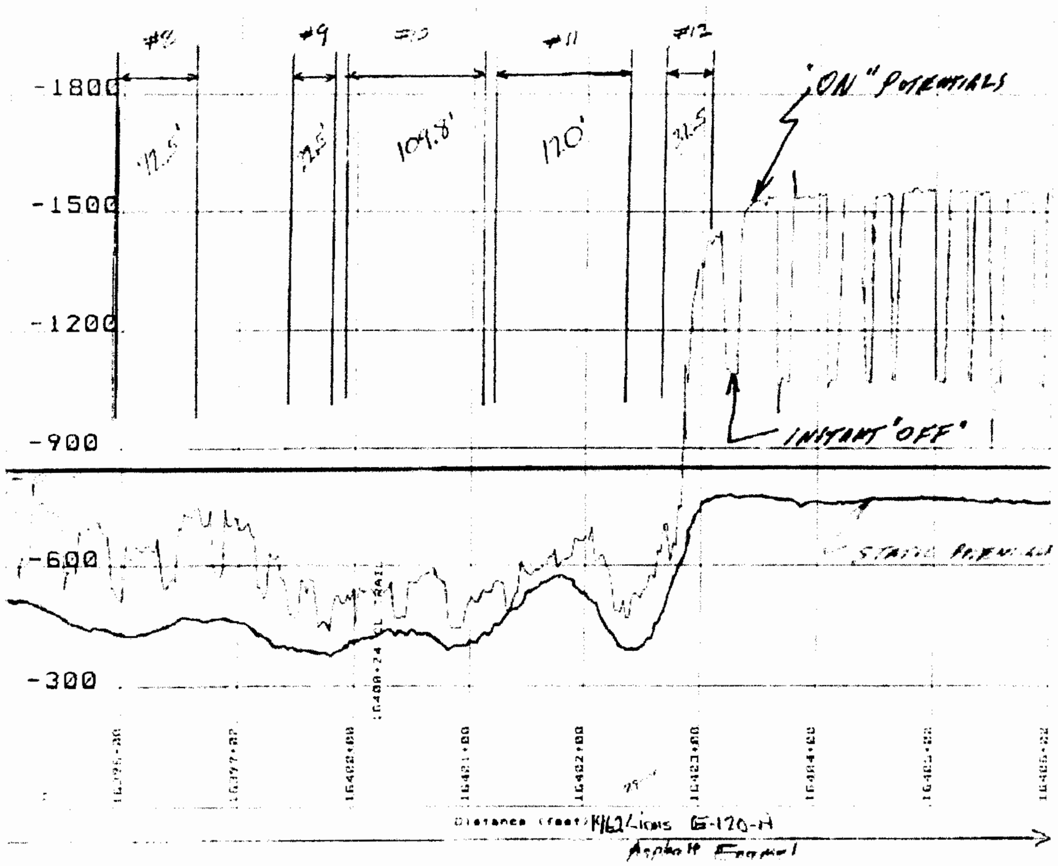
Criteria Close Interval Survey Graph



This graph shows typical data collected during a criteria close interval survey. All three energy levels are shown on the survey graph. The "on" pipe to soil potentials are near the -1200mV level, and the "instant off" or "polarized" potentials are near the -1050mV level. The "static" or "native" pipe-soil potentials are near the -600mV level.

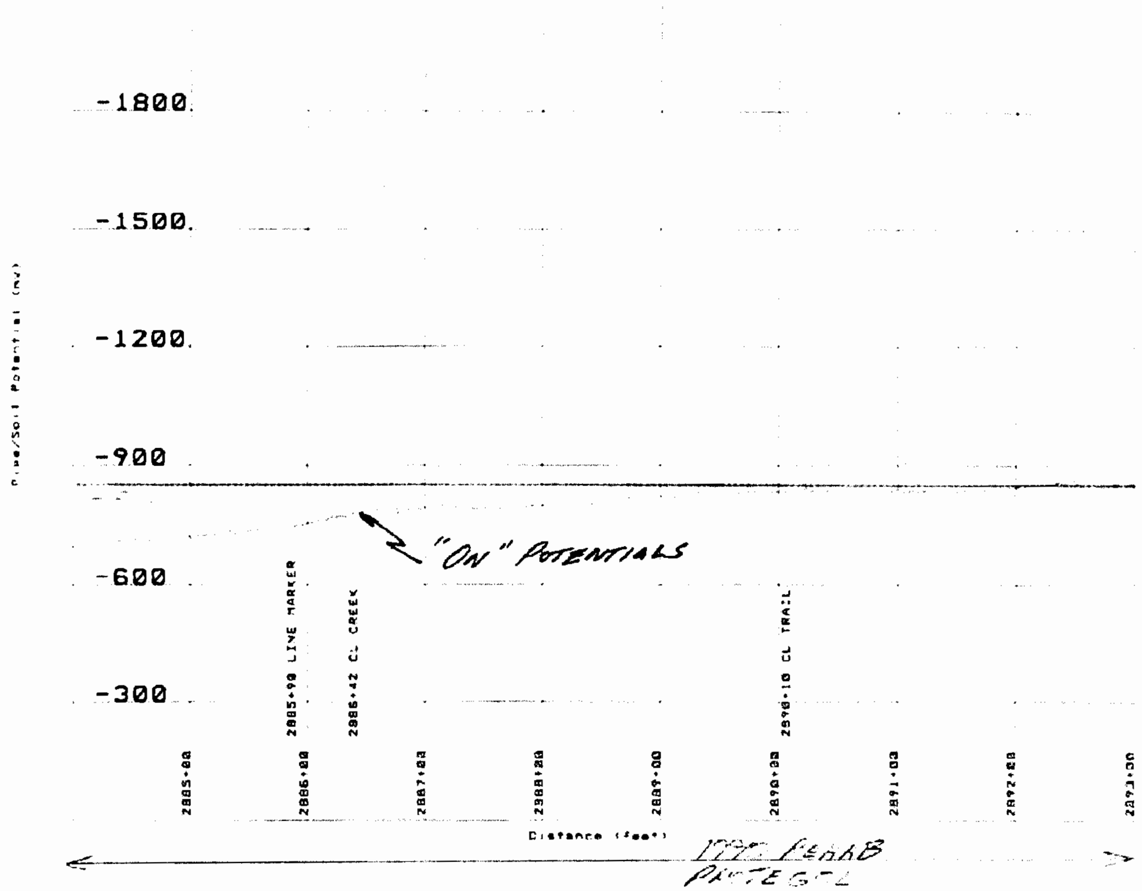
This graph shows a pipeline with excellent coating and no indications of coating damage or cathodic protection levels not providing adequate protection to the pipeline. The difference between the "instant off" potentials and the "static" potentials is greater than 400mV which is substantially greater that the regulatory requirement of 100mV. Both the "on" potentials and IR free "instant off" potentials are greater than -850mV and also within regulatory. No areas on this pipeline would require remedial measures.

Criteria Close Interval Survey Graph (Poor Coating Conditions)



This graph shows a criteria close interval survey with severely damaged coating conditions on the left side, and well coated conditions on the right side. The green "static" potential line indicates corrosion has probably occurred to the pipe due to the low energy levels (-350 to -450mV range) compared to the approximately -700mV level on the right side of the graph. The "on/instant off" potentials have dropped dramatically below the red -850mV line, and in some areas blended together as a single energy level. The bottom of the saw toothed "instant off" potential line is in close proximity to the "static" potential line and therefore less than -100mV spacing between them. This is an indication that severe coating damage has occurred, possible metal loss has occurred to the pipeline, and that the cathodic protection level does not meet regulatory requirements. The markings above the left area are where a corrosion technician has marked the areas where graphically the 100mV criterion is not being achieved. All of the pipeline segments indicated below the red -850mV line would require remediation. This is the type anomaly that would be identified on the Action Plan as requiring investigation and remediation.

Close Interval Survey Graph (Low Cathodic Protection Conditions)



This close interval survey graph shows the "on" potentials drift above and below the -850mV red line but has no dramatic dip in the line to indicate a possible damaged coating area. The pipeline appears to be well coated, but lacking in enough cathodic protection energy to bring the pipe to soil potentials above the criteria level of -850mV. This type anomaly would be indicated in the Action Plan with associated remedial activities including the installation of additional cathodic protection facilities and/ or increasing output from existing cathodic protection facilities.

Action Plan/ Closure Document

The following is a check list of items that should be included in the Action Plan and Closure Report documents for close interval surveys.

Action Plan:

1. Dates
    a. Date the close interval survey was performed
    b. Date the graded close interval survey report was received
    c. Date the action plan was published
2. Summary Statement

State whether the Action Plan requires work activity, or that the Action Plan is also the Closure Document.

3. Discussion
    a. Events and activities associated with the survey
    b. Name of the contractor who performed the survey
    c. Pipeline segment the survey was performed on and specific to location
    d. Discussion of existing cathodic protection system
    e. Discussion of coating types, condition, year coating installed
    f. Summary of survey results
    g. Review and summary of past close interval surveys,
    h. Past in-line inspection smart tool surveys compared to the results of the close interval survey
    i. Environmental conditions - population class location number
4. Recommendation
    a. Use this letter as documentation for an Action Plan
    b. Identify remedial actions to be implemented
5. Support Documents
    a. Marked up close interval report pages for the anomalies requiring remediation
    b. Strip maps, current density calculations, or other field notes used to define areas requiring remediation

Closure Document:

1. Formal Statement
   A letter stating that all work activities required by the Action Plan have been completed.
2. Discussion
    a. Restate when the survey took place, graded survey received, and when the Action Plan was published.
    b. Results of the Action Plan work items.

3. Support Documents
    a. Form 300-1, Pipeline Maintenance, Repair & Inspection Report with photographs, corrosion sketches, etc.

Attachment 4

CRITERIA FOR GRADING DIRECT CURRENT VOLTAGE GRADIENT SURVEYS

This document establishes guidelines and methodology for evaluating and grading DCVG cathodic protection surveys. A DCVG survey is a direct current voltage gradient survey methodology to locate and grade damaged pipeline coating areas. DCVG surveys are effective on well coated pipelines with limited coating degradation. DCVG surveys do not work on pipelines with severe coating degradation and high current densities.

DCVG Cell to Cell Close Interval Surveys

A DCVG cell to cell survey close interval survey produces a report evaluating each coating defect located during the survey. The defects are sized relative to the signal voltage (or potential swing) to remote earth (mV1) to the signal voltage (potential swing) recorded at the nearest test point (mV2). DCVG surveys can provide information needed to determine whether active corrosion is taking place at the defect.

Grading the Survey

DCVG survey readings are graded into four groups based on the approximate anomaly size as follows, and four categories for assessing the corrosion state of the holiday. The following describes these four categories and four corrosion states:

(Sizing)

Category 1: 1 to 15% IR - This category is used when a pipeline is surveyed that is coated with Fusion Bonded Epoxy or similar coatings. For older pipelines coated with coal tar enamels, asphalt enamels, etc., this category of data is not collected during the survey. Coating holidays in this category are often considered of low importance, and coating repair is generally not required. A properly maintained cathodic protection system typically provides effective long term protection to these anomaly areas.

Category 2: 16 to 35% IR - Coating holidays are suggested for investigation and repair, based on their proximity to cathodic protection groundbeds. The holidays are generally considered a threat and are likely to be adequately protected by a maintained cathodic protection system. This type of holiday may be considered for additional monitoring due to fluctuations in the levels of protection could alter the status as the coating further degrades.

Category 3: 36 to 60% IR - Coating holidays in this category are generally considered requiring repair. The amount of exposed steel in such a holiday size indicates it may be a major consumer of protective cathodic protection current and that serious coating damage may be present. These holidays would normally be recommended for repair based on their proximity to cathodic protection groundbeds and other records indicating the level of cathodic protection and whether it is sustained in the area.

Category 4: 61 to 100% IR - Coating holidays in this category are generally recommended for immediate or scheduled repair. The amount of exposed steel indicates that the holiday is a major consumer of protective cathodic protection current and that massive coating damage may be present. Category 4 holidays typically indicate the potential for very serious problems with the coating and are often considered likely to pose a threat to the overall integrity of the pipeline.

Corrosion States

DCVG data distinguishes the direction of current flow in the soil. Because corrosion results in current flow away from the coating faults and cathodic protection results in current flow to the coating faults, the electrochemical activity to the exposed steel can be determined. The current flow is determined while the cathodic protection is both "on" and "off" and is a characteristic of the individual holiday. There are four categories for assessing the corrosion state at a holiday:

C/C - cathodic/cathodic - This category refers to holidays that are cathodic (protected) while the cathodic protection is "on" and remain polarized when the cathodic protection is interrupted or "off". These type anomalies are minor consumers of cathodic protection current but are not actively corroding.

C/N - cathodic/neutral - This category refers to holidays that appear to be protected while the cathodic protection system is "on" but return to a native state when the cathodic protection is interrupted. These anomalies consume cathodic protection current and may corrode when there is an upset in the system for a period of time.

C/A - cathodic/anodic - This category refers to coating holidays that appear to be protected while the cathodic protection system is "on" and appear anodic when the cathodic protection is interrupted. Because the interrupted value corresponds to the potential at the interface between the pipe and the soil, the pipeline at these holidays may corrode even when the cathodic protection is operating properly. This type of defect consumes cathodic protection current, and requires scheduled remediation for coating repair or additional cathodic protection.

A/A - anodic/anodic - This category refers to coating holidays that receive no protective cathodic protection regardless of whether the cathodic protection system is "on" or "off". It is possible that corrosion is present and may or may not consume any cathodic protection energy. This is the most severe condition because it is the most prone to active corrosion, followed by the C/A category. This type defect requires immediate remediation by excavation and coating repair or adjustments to the cathodic protection system to provide protective current flow.

Action Plan/ Closure Document

The following is a check list of items that should be included in the Action Plan and Closure Report documents for DCVG surveys.

Action Plan:

1. Dates
    a. Date the DCVG survey was performed
    b. Date the graded DCVG survey report was received
    c. Date the action plan was published

2. Summary Statement

   State whether the Action Plan requires work activity, or that the Action Plan is also the Closure Document.

3. Discussion

   a. Events and activities associated with the survey
   b. Name of the contractor who performed the survey
   c. Pipeline segment the survey was performed on and specific to location
   d. Discussion of existing cathodic protection system
   e. Discussion of coating types, condition, year coating installed
   f. Summary of survey results
   g. Review and summary of DCVG surveys,
   h. Past in-line inspection smart tool surveys compared to the results of the DCVG
   i. Environmental conditions - population class location number

4. Recommendation

   a. Use this letter as documentation for an Action Plan
   b. Identify remedial actions to be implemented

5. Support Documents

   a. Marked up DCVG report pages for the anomalies requiring remediation
   b. Strip maps or other field notes used to define areas requiring remediation

Closure Document:

1. Formal Statement

   a. A letter stating that all work activities required by the Action Plan have been completed.

2. Discussion

   a. Restate when the survey took place, graded survey received, and when the Action Plan was published.
   b. Results of the Action Plan work items.

3. Support Documents

   a. Form 300-1, Pipeline Maintenance, Repair & Inspection Report with photographs, corrosion sketches, etc.

Objective
To provide good quality welds in accordance with recognized industry standards on all modifications and repairs.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR Part 192, Subpart E, 192.221 thru 192.245 and Appendix A & C
API 1104 (19^{th} Edition)
ASME Boiler and Pressure Vessel Code

Welding Procedures
All welding shall be done by a qualified welder in accordance with a welding procedure qualified per API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code. The procedure shall be determined by destructive testing.

Qualification Records
Records of the tests that establish the qualification of a welding procedure shall be maintained as long as that procedure is in use. A record of the welders qualified per the requirements below, showing the date and results of tests, shall also be maintained.

Welder Qualification Requirements
Each welder must be qualified in the welding procedure in Section 503 of this manual in accordance with Section 6 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code. The Welder Qualification Record shall be obtained and filed prior to performing any work on this pipeline.

A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20% of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in the Basic Test, shown below.

After initial qualification, a welder may not perform welding unless:
1. Within the preceding 15-calendar months, the welder has re-qualified, except that the welder must re-qualify at least once each calendar year; or
2. Within the preceding 7-1/2 calendar months, but at least twice each calendar year, the welder has had a production weld cut out, tested and found acceptable in accordance with the qualifying test.

Basic Test
This test is limited to welders who work on lines operating at a hoop stress of less than 20% of SMYS. The test is made on pipe 12 inches or less in diameter. The test weld must be made with pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. The weld is unacceptable if, as a result of this test, two or more of the coupons develop a crack in the weld material or between the weld material and base metal that is more than 1/8-inch long in any direction. Cracks that occur on the corner of the specimen during testing are not considered.

Welder Limitations

No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

No welder may weld with a particular welding process unless, within the preceding 6 calendar months, the welder has engaged in welding with that process.

A welder qualified under 192.227 (a) may not weld unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under Section 6 of API Standard 1104 (19^{th} Edition), except that a welder qualified under an earlier edition previously listed in Appendix A (Pipeline Safety Rules) may weld but may not re-qualify under the earlier edition.

Weather

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

Miter Joints

A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30% or more of SMYS may not deflect the pipe more than 3 degrees.

A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30%, but more than 10%, of SMYS may not deflect the pipe more than 12.5° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10% or less of SMYS may not deflect the pipe more than 90 degrees.

Preparation for Welding

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

Inspection and Testing of Welds

Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure and the weld is acceptable under the following paragraph of this section.

The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of API Standard 1104.

The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be nondestructively tested in accordance with 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

1. The pipeline has a nominal diameter of less than 6 inches; or
2. The pipeline is to be operated at a pressure that produces a hoop stress of less than 40% of SMYS and the welds are so limited in number that nondestructive testing is impractical.

Nondestructive Testing of Welds

Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

Nondestructive testing of welds must be performed in accordance with written procedures and by persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld according to the standards in section 6 of API Standard 1104.

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).

(d) When nondestructive testing is required under §192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under §192.241(b).

(f) When nondestructive testing is required under §192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

Repair and Removal of Defects

Each weld that is unacceptable under 192.241(c) must be removed or repaired. A weld must be removed if it has a crack that is more than 8 % of the weld length.

Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

Repair of a crack, or any defect in a previously repaired area must be in accordance with written weld repair procedures that have be qualified under 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

Objective
Install fixed gas detection and alarm system at each compressor building which is more than 1,000 horsepower and has more than 50% of its upright area enclosed.

Reference
Minimum Federal Safety Standards for Natural Gas Pipelines
49 CFR 192.736

Design Requirements
(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

COPY

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

<u>**CERTIFIED MAIL - RETURN RECEIPT REQUESTED**</u>

September 7, 2011

Mr. John Mollenkopf
COO/Senior Vice President
Markwest Oklahoma Gas Company, LLC
1515 Arapahoe Street, Tower I, Suite 1600
Denver, CO 80202-2126

CPF 4-2011-1009M

Dear Mr. Mollenkopf:

Between April and June, 2011, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Markwest Oklahoma Gas Company, LLC(Markwest) procedures for Operations and Maintenance.

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

1. **§192.16 Customer notification**

    (b) Each operator shall notify each customer once in writing of the following information:

    (1) The operator does not maintain the customer's buried piping.
    (2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
    (3) Buried gas piping should be -

    (i) Periodically inspected for leaks;
    (ii) Periodically inspected for corrosion if the piping is metallic; and
    (iii) Repaired if any unsafe condition is discovered.

received
9-12-11

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996 or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meters systems may continuously post a general notice in a prominent location frequented by customers.

Markwest did not have a procedure to notify each customer once in writing required by §192.16 informing them that they do not maintain the customer's buried piping to the entry of the first building downstream or up to the principal gas utilization equipment or the first fence that surrounds the equipment. Markwest must amend their procedure to include customer notification of customer piping in accordance with §192.16.

2. **§192.613 Continuing Surveillance.**

   (a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

Markwest's Section 401 Surveillance/Reporting Summary, page 69-70, Procedures were inadequate. The current procedure states what is needed in order to conduct the continuing surveillance program review, but it does not state what the review encompasses or what actions to take if there are changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

Markwest must modify the procedures to provide sufficient detail for conducting continuing surveillance on their pipeline system to meet the requirements of §192.613(a).

3. **§192.736 Compressor stations: Gas detection.**

   (a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is-

   (1) Constructed so that at least 50 percent of its upright side area is permanently open; or

   (2) Located in an unattended field compressor station of 1,000 horsepower (746 kilowatts) or less.

Markwest did not have a procedure in their O&M Manual to install fixed gas detection and alarm system at each compressor building which is 50 percent enclosed and has more than 1,000 horsepower. The procedure was in their Construction specifications, which needs to be incorporated or referenced in their O&M Manual.

Markwest needs to amend their procedures to include the installation of fixed gas detection and alarm system at each compressor station and meet the requirements of §192.736.

4. **§192.227 Qualification of welders.**

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 6 of API 1104 (incorporated by reference, see § 192.7) or section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference, see §192.7). However, a welder qualified under an earlier edition than listed in § 192.7 of this part may weld but may not requalify under that earlier edition.

Markwest's Section 503 Welding of Steel Pipelines Procedures, page 131, were inadequate. The procedure states that welders will be qualified in accordance with Section 3 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code. The procedure does not state what edition, either the 19th or 20th, of API 1104 will be followed during welder qualifications. In addition the welder must be qualified in accordance to Section 6 not Section 3 of API 1104.

Markwest needs to amend their procedures to meet the requirements of §192.227(a).

5. **§192.243 Nondestructive testing.**

d) When nondestructive testing is required under §192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference;

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

Markwest's Section 503, Welding of Pipelines, Nondestructive Testing of Welds Procedures on page 133 were inadequate. The procedure did not require 100 percent nondestructive testing in Class 3 and Class 4 locations at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, unless impracticable, in which case at least 90 percent must be tested. The procedure was in their Construction specifications, which needs to be incorporated or referenced in their O&M Manual.

Markwest needs to amend their procedures to meet the requirements of §192.243(d)(3).

6. **§192.477 Internal corrosion control: Monitoring**

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 1/2 months.

Markwest's Section 405, Corrosion Control, Internal Corrosion Control Procedures on page 98, were inadequate. The procedures are inadequate in determining the methods or equipment used to determine the effectiveness of the steps taken to minimize internal corrosion.

Markwest must amend their procedures to include the method that will be used to determine the effectiveness of their internal corrosion program and meet the requirements of §192.477.

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 45 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 4-2011-1009M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, SW Region
Pipeline and Hazardous
Materials Safety Administration

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

Response Options for Pipeline Operators in Compliance Proceedings

The requirements of 49 C.F.R. Part 190, Subpart B (§§ 190.201–190.237) govern response to Notices issued by a Regional Director, Pipeline and Hazardous Materials Safety Administration (PHMSA).

Be advised that all material submitted by a respondent in response to an 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).

I. **Procedures for Responding to a NOTICE OF PROBABLE VIOLATION:**

Within 30 days of receipt of a Notice of Probable Violation, the respondent shall respond to the Regional Director who issued the Notice in the following way:

a. When the Notice contains a proposed **CIVIL PENALTY*** --

1. If you are not contesting any violations alleged in the Notice, pay the proposed civil penalty and advise the Regional Director of the payment. This authorizes PHMSA to issue an order making findings of violation and upon confirmation that the payment has been received PHMSA will close the case with prejudice to the respondent. Payment terms are outlined below;

2. If you are not contesting any violations alleged in the Notice but wish to submit written explanations, information, or other materials you believe warrant mitigation of the civil penalty, you may submit such materials. This authorizes PHMSA to make findings and to issue a Final Order assessing a penalty amount up to the amount proposed in the Notice. Refer to 49 C.F.R. § 190.225 for assessment considerations, which include the respondent's ability to pay and the effect on the respondent's ability to stay in business, upon which civil penalties are based;

3. If you are contesting one or more of the items in the Notice but are not requesting an oral hearing, submit a written response to the allegations and/or seek elimination or mitigation of the proposed civil penalty; or

4. Request a hearing as described below to contest the allegations and/or proposed assessment of a civil penalty.

b. **When the Notice contains a proposed COMPLIANCE ORDER* --**

1. If you are not contesting the compliance order, notify the Regional Director that you intend to take the steps in the proposed compliance order;

2. If you are not contesting the compliance order but wish to submit written explanations, information, or other materials you believe warrant modification of the proposed compliance order in whole or in part, or you seek clarification of the terms of the proposed compliance order, you may submit such materials. This authorizes PHMSA to make findings and issue a compliance order;

3. If you are contesting the proposed compliance order but are not requesting an oral hearing, submit written explanations, information, or other materials in answer to the allegations in the Notice and stating your reasons for objecting to the proposed compliance order items in whole or in part; or

4. Request a hearing as described below to contest the allegations and/or proposed compliance order items.

c. **When the Notice contains a WARNING ITEM --**

No written response is required. The respondent is warned that if it does not take appropriate action to correct these items, enforcement action will be taken if a subsequent inspection reveals a violation.

* Failure of the respondent to respond to the Notice within 30 days of receipt constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

II. Procedures for Responding to a NOTICE OF AMENDMENT*--

Within 30 days of receipt of a Notice of Amendment, the respondent shall respond to the Regional Director who issued the Notice in the following way:

a. If you are not contesting the Notice, notify the Regional Director of your plans to address the inadequacies identified in the Notice;

b. If you are not contesting the Notice but wish to submit written explanations, information, or other materials you believe warrant modification of the Notice of Amendment in whole or in part, or you seek clarification of the terms of the

Notice of Amendment, you may submit such materials. This authorizes PHMSA to make findings and issue an Order Directing Amendment;

c. If you are contesting the Notice of Amendment but are not requesting an oral hearing, submit written explanations, information, or other materials in answer to the allegations in the Notice and stating your reasons for objecting to the Notice of Amendment items in whole or in part; or

d. Request a hearing as described below to contest the allegations in the Notice.

* Failure of the respondent to respond to the Notice within 30 days of receipt constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

III. Procedure for Requesting a Hearing

A request for a hearing must be in writing and accompanied by a statement of the issues that the respondent intends to raise at the hearing. The issues may relate to the allegations, new information, or to the proposed compliance order or proposed civil penalty amount. Refer to 49 C.F.R. § 190.225 for assessment considerations upon which civil penalties are based. A respondent's failure to specify an issue may result in waiver of the right to raise that issue at the hearing. The respondent's request must also indicate whether or not respondent will be represented by counsel at the hearing. Failure to request a hearing in writing within 30 days of receipt of a Notice waives the right to a hearing. In addition, if the amount of the proposed civil penalty or the proposed corrective action is less than $10,000, the hearing will be held by telephone, unless the respondent submits a written request for an in-person hearing. Complete hearing procedures can be found at 49 C.F.R. § 190.211.

IV. Extensions of Time

An extension of time to prepare an appropriate response to a Notice may be granted, at the agency's discretion, following submittal of a written request to the Regional Director. The request must indicate the amount of time needed and the reasons for the extension. The request must be submitted within 30 days of receipt of the Notice.

V. Freedom of Information Act

Any material provided to PHMSA by the respondent, and materials prepared by PHMSA including the Notice and any order issued in this case, may be considered public information and subject to disclosure under the Freedom of Information Act (FOIA). If you believe the information you are providing is security sensitive, privileged, confidential or may cause your company competitive disadvantages, please clearly identify the material and provide justification why the documents, or portions of a document, should not be released under FOIA. If we receive a request for your material, we will notify you if PHMSA, after reviewing the materials and your provided justification, determines that withholding the materials does not meet any exemption

provided under the FOIA. You may appeal the agency's decision to release material under the FOIA at that time. Your appeal will stay the release of those materials until a final decision is made.

VI. Small Business Regulatory Enforcement Fairness Act Information

The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of the Pipeline and Hazardous Materials Safety Administration, call 1-888-REG-FAIR (1-888-734-3247) or go to http://www.sba.gov/ombudsman/dsp_faq.html.

VII. Payment Instructions

Civil Penalty Payments of Less Than $10,000

Payment of a civil penalty of less than $10,000 proposed or assessed, under Subpart B of Part 190 of the Pipeline Safety Regulations can be made by certified check, money order or wire transfer. Payment by certified check or money order (containing the CPF Number for this case) should be made payable to the "Department of Transportation" and should be sent to:

> Federal Aviation Administration
> Mike Monroney Aeronautical Center
> Financial Operations Division (AMZ-341) P.O. Box 269039
> Oklahoma City, OK 73125-4915

Wire transfer payments of less than $10,000 may be made through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfer should be directed to the Financial Operations Division at (405) 954-8893, or at the above address.

Civil Penalty Payments of $10,000 or more

Payment of a civil penalty of $10,000 or more proposed or assessed under Subpart B of Part 190 of the Pipeline Safety Regulations must be made wire transfer (49 C.F.R. § 89.21 (b)(3)), through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfers should be directed to the Financial Operations Division at (405) 954-8893, or at the above address.

INSTRUCTIONS FOR ELECTRONIC FUND TRANSFERS

(1) RECEIVER ABA NO. 021030004	(2) TYPE/SUB-TYPE (Provided by sending bank)
(3) SENDING BANK ABA NO. (Provided by sending bank)	(4) SENDING BANK REF NO. (Provided by sending bank)
(5) AMOUNT	(6) SENDING BANK NAME (Provided by sending bank)
(7) RECEIVER NAME TREAS NYC	(8) PRODUCT CODE (Normally CTR, or as provided by sending bank)
(9) BENEFICIAL (BNF) = AGENCY LOCATION CODE BNF = /ALC-69-14-0001	(10) REASONS FOR PAYMENT Example: PHMSA - CPF # / Ticket Number/Pipeline Assessment number

INSTRUCTIONS: You, as sender of the wire transfer, must provide the sending bank with the information for blocks (1), (5), (7), (9), and (10). The information provided in Blocks (1), (7), and (9) are constant and remain the same for all wire transfers to the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #1 - RECEIVER ABA NO. - "021030004". Ensure the sending bank enters this 9-digit identification number; it represents the routing symbol for the U.S. Treasury at the Federal Reserve Bank in New York.

Block #5 - AMOUNT - You as the sender provide the amount of the transfer. Please be sure the transfer amount is punctuated with commas and a decimal point. **EXAMPLE: $10,000.00**

Block #7 - RECEIVER NAME - "TREAS NYC". Ensure the sending bank enters this abbreviation. It must be used for all wire transfers to the Treasury Department.

Block #9 - BENEFICIAL - AGENCY LOCATION CODE - **"BNF=/ALC-69-14-0001"**. Ensure the sending bank enters this information. This is the Agency Location Code for the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #10 - REASON FOR PAYMENT - **"AC-payment for PHMSA Case # /** To ensure your wire transfer is credited properly, enter the case number/ticket number or Pipeline Assessment number, and country."

NOTE: A wire transfer must comply with the format and instructions or the Department cannot accept the wire transfer. You as the sender can assist this process by notifying the Financial Operations Division (405) 954-8893 at the time you send the wire transfer.

February 2009