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June 20, 2007

Linda Daugherty
Director, Southern Region
Pipeline and Hazardous Materials Safety Administration
233 Peachtree Street, Ste. 600
Atlanta, GA 30303

CPF 2-2007-5004M

Dear Ms. Daugherty,

This letter is in response to the May 2, 2007 Notice of Amendment MarkWest Energy Appalachia, L.L.C. received from the Pipeline and Hazardous Materials Safety Administration regarding an audit that was conducted on December 5-9, 2005.

Responses to the audit findings and supporting documentation are attached for review.

Feel free to contact me if you have any questions or need additional information.

Sincerely,

Bruce Gillick
Director of Environmental, Health & Safety
MarkWest Energy Partners, L.P.
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MarkWest Responses to the OPS Audit of the Appalachia Pipeline

Item 1.A

MarkWest welding procedures are incorrect. *Operations, Maintenance, and Emergencies Manual* (OM&E Manual) Section 6.54 references Section 2 of API 1104, instead of Section 5. It is also noted that OM&E Manual Section 6.5 similarly incorrectly references other sections of API 1104. See §§ 195.222(a), 195.234(b), and 195.230 to correct these inadequacies.

RESPONSE

All references to sections of API 1104 have been corrected to reflect the version incorporated by reference in accordance with §195.3 (19th edition, 1999 and its October 31, 2001 errata). Included is a copy of the revised edition of OM&E Manual Section 6.5 Welding.

Item 1.B

OM&E Manual Section 6.6 *Hydrostatic Test Requirements* does not require the temperature of the test medium or pipe to be recorded during the test period.

Response

The Temperature of the test medium or pipe is being documented during hydrotesting and recorded on OM&E Manual FORM 118 *Field Pressure & Test Report*. OM&E Manual Section 6.6 has been updated to include requiring the temperature of the test medium or pipe to be recorded during the testing period as per §195.310. Included is a copy of the revised edition of OM&E Manual Section 6.6 *Hydrostatic Test Requirements*.

Item 2

OM&E Manual Section 7.5 *Abandonment or Deactivation of Facilities* and Form 102 *MarkWest Abandonment or Deactivation of Facilities* are inadequate in that they do not differentiate between *abandonment* and *deactivation*. *Deactivation* is not defined and procedures do not specify the conditions under which operations and/or maintenance requirements, such as leak surveys, cathodic protection, public awareness programs, etc., can be terminated on *deactivated* pipelines.

Response

OM&E Manual Section 2 *Definitions* has been updated to include additional information within the definition of 'Abandoned'. A definition for 'Deactivated'

has been added to further differentiate between *abandoned* and *deactivated*. OM&E Manual Section 7.5 has also been updated to include information pertaining to deactivated pipelines. Included is a copy of the revised edition of OM&E Manual Section 2 and Section 7.5.

Item 3

MarkWest procedures do not address the requirement to determine the effectiveness of procedures, as required of §195.402(c)(13). OM&E Manual Section 7.9 *Training* conveys the following.
Once per year and at intervals not to exceed fifteen months, MarkWest shall evaluate . . . the program's effectiveness in achieving its objectives by reviewing personnel performance. Make any appropriate changes to the training program as necessary to ensure its effectiveness.

Response
OM&E Manual Section 7.9 *Training* has been updated to include additional information on procedure evaluation. Included is a copy of the revised edition of OM&E Manual Section 7.9.

Item 4

MarkWest procedures do not require personnel to have hand tools and flame retardant clothing available at the scene of an emergency. These items are necessary, based on conversation with MarkWest employees.

Response
OM&E Manual Section 5.1.1 has been updated to include various tools and equipment personnel will have on hand at the scene of an emergency. Included is a copy of the revised edition of OM&E Manual Section 5.1.1.

Item 5

MarkWest procedures do not adequately address the requirement to assess the extent and coverage of a vapor cloud and determine the hazardous areas. OM&E Manual Section 5.1.5 (b) requires the use of detection instruments to determine the concentration of HVL vapors in the area, but does not provide adequate details on how this will be done. MarkWest procedures do not address how to determine the potential cloud location, size, dispersion, and movement so that a monitoring plant with instruments can be developed and implemented to identify the cloud coverage and hazard areas. Use of information such as terrain elevations, underground drainage systems, weather and wind information, spill volume, and length of time since release are not included in the procedures. The number of available detection instruments and personnel should reflect the requirements of the plan. Below is an excerpt from OM&E Manual Section 5.1.5 (b).

A combustible gas indicator or "flame ionization gas detector" shall be used by a qualified MarkWest employee to determine the concentration of HVL vapors in the area. In the instance where flammable highly volatile liquids are present, the supervisor shall use an "explosimeter" to determine the extent and coverage of the vapor cloud and determine the hazardous areas.

<u>Response</u>

MarkWest has developed and implemented a procedure (IM-001 Volume Release and HCA Impact) within its Integrity Management Program to determine how a pipeline could affect its surrounding environment. This process first requires the determination of worse case release volumes, which ultimately are used to determine surrounding environment impact via overland spread, water transport and air dispersion. The type of modeling performed is product specific.

Worse case volume release was determined using the following data:
Pipe characteristics
Medium
Elevation profile
Valve location, type and closure type
Maximum flow rate
Time to confirm a leak and shutdown

For HVL segments, MarkWest has performed air dispersion analysis using the ARCHIE Model in order to determine the impact zone under a variety of circumstances (e.g., pooling versus light end dispersion, toxicity based on wind speed, flame jet, pool fire radiation and vapor cloud explosion). After review of the ARCHIE model and risk analysis results, MarkWest has elected to consider all of its HVL pipeline mileage to be subject to 195.452, based on the high risk associated with these pipelines when compared to crude pipeline assets.

The results of the ARCHIE Modeling are being used to develop a basis for the Public Awareness Program and Emergency Response Plans, as well as to determine resource requirements for employees, contractors and equipment. Section 5 of the OME Manual details the requirements for emergencies.

Changes have been made to OM&E Manual Section 5 to further elaborate on steps being performed once MarkWest personnel have arrived at an emergency location. Two separate sentences were added into this section regarding assistance, and advising emergency response personnel with the characteristics of the product. Information from IMP Manual Appendix D *HCA Impacts and Results* has been incorporated into a table and included within Section 5. A table including distances between facilities and pipeline motor operated control valves detailing piping

information and total volume of product has been incorporated into Section 5 for use during emergency conditions.

Item 6A

The Kenova cell phone number is not listed on the Kenova emergency call list (OM&E Manual Section 11.2.2). The number was recommended to be distributed in a 2004 Abnormal Condition Review.

Response
The Kenova cell phone number has been added to OM&E Manual Section 11.2.2. Included is a copy of the revised edition of OM&E Manual Section 11.2.2.

Item 6B

MarkWest procedures do not adequately address the requirements of §195.426, as indicated in the following excerpt from OM&E Manual Section 7.11. The excerpt only applies to launchers and receivers with vent valves, whereas §195.426 applies to all launchers and receivers. Also, allowing personnel to monitor the vent valve for audible and visual indications to insure the pressure has been relieved before opening the barrel to install or remove scrapers and spheres does not satisfy the requirement to use a suitable device, such as a pressure gauge, to indicate that pressure has been relieved.

For pipelines having scraper and sphere launching and receiving facilities with vent valves to depressurize the barrel, operators shall either monitor the vent valve for audible and visual indications, or install and observe pressure readings on a pressure gauge, to insure the pressure has been relieved before opening the barrel to install or remove scrapers or spheres.

Response
OM&E Manual Section 7.11 has been modified in accordance with §195.426. Included is a copy of the revised edition of OM&E Manual Section 7.11.

Item 6C

MarkWest procedures do not require adequate fire fighting equipment to be maintained at Kenova pump station, as required of §195.430.

Response
OM&E Manual Section 5.2 has been updated in accordance with §195.430. Included is a copy of the revised edition of OM&E Manual Section 5.2.

Item 6D

MarkWest procedures are not adequately descriptive. OM&E Manual Section 6.1 mimics the regulations, does not convey that MarkWest's recently installed SCADA system is a CPM system, and does not state the applicable requirements of the referenced section of API 1130. Excerpt from OM&E Manual Section 6.11 is listed below.

This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system shall comply with Section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system.

Response
OM&E Manual Section 6.11 has been updated in accordance with API 1130 Section 4.2. OM&E Manual Section 7.2 has been updated to include information detailing that a SCADA system is a CPM system. OM&E Manual Section 3 has also been updated to include the definition of SCADA. Included is a copy of the revised edition of OM&E Manual Sections 6.11, 7.2 and Section 3.

Item 6E

External protective coating procedures (OM&E Manual Sections 6.4.7 and 9.3) mimic the regulations, are very general, and do not provide a list of approved coating products and stated applications and restrictions. OM&E Manual Section 9.3 allows for coatings to be . . . *such as 'thin film epoxy", TGF-3, or any other acceptable coating. . . . Joints, fittings, and tie-ins shall be coated with materials compatible with the coating on the pipe."*

Response
A pipeline coating chart has been created detailing the type of coating, manufacturer, PPE requirements, applications and restrictions. This chart has been included in OM&E Manual Section 9 as Appendix 9.1 *Pipeline Coating Chart*. A reference has been added to Appendix 9.1 in OM&E Sections 6.4.7 and 9.3. Included is a copy of the revised edition of OM&E Manual Sections 6.4.7, 9.3 and Appendix 9.1.

Item 6F

MarkWest procedures do not convey the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE standard RP0169-96. For protected pipelines, OM&E Manual Section 9.2.2 indicates the objectives of NACE standard RP0169-96 §10.1.1.3

are to be met not more than two years after cathodic protection is installed. No applicable identified circumstances are found in the procedures.

Response
The table within OM&E Manual Section 9.2.2 has been updated to include information on close interval survey requirements with protected pipelines. Included is a copy of the revised edition of OM&E Manual Section 9.2.2.

Item 6G

MarkWest procedures are not specific in how MarkWest determines areas of active corrosion. Procedures do not convey specific criteria used in determining the areas where active corrosion, unless controlled, could result in a condition that is detrimental to public safety. The procedures convey that consideration should be given to those areas near people, homes, buildings, road crossings, and pipeline operating pressures, and that boundaries of Active Corrosion Zones will be determined; however, no specific criteria was found as to how these areas are established.
Excerpts from OM&E Manual Section 3.1 *Definitions*
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 *– An area where the public could be exposed to hazards caused by active corrosion. Boundaries of other "Active Corrosion Zones" will be determined by an Engineering Services Pipeline/Corrosion/Pipeline Safety Engineer. This method will not apply to pipelines under cathodic protection.*

Response
MarkWest provides procedure IM-012, Examination of Pipe and Associated Facilities which details specific procedures for the determination of active corrosion.

Item 6H

MarkWest procedures do not convey the time allowed to correct a condition (that could adversely affect the safe operation of the pipeline) discovered while performing annual corrosion monitoring surveys. OM&E Manual Section 9.12.1 conveys: *If adequate protection is not indicated, corrective steps shall be taken to restore the structure to the proper degree of protection.* Procedures do not address how much time is allowed to correct the condition.

Response

A response table has been incorporated within OM&E Manual Section 9.12.1 to include time frames for remediation of low potential conditions found during an Annual Corrosion Monitoring Survey. Information has also been incorporated

within this section to require a remedial action plan in the event that a condition cannot be corrected within the specified time frame.

Item 7A

MarkWest's Operator Qualification Program (rev. January, 2005) does not include provisions to ensure thorough evaluation that individuals performing covered tasks are qualified. The program does not convey that after December 16, 2004, observation of on-the-job performance may not be used as a sole method of evaluation.

Response

The MarkWest Operator Qualification program was revised (June 2007) to include provisions to ensure thorough evaluations of individuals performing covered tasks. In addition, a statement conveying that observation of on-the-job performance may not be used as a sole method of evaluation has been incorporated into the program. Included is the MarkWest revised edition (June 2007) Operator Qualification program.

Item 7B

MarkWest's Operator Qualification Program (rev. January, 2005) does not include provisions for training, as appropriate, as required of §195.505(h).

Response

The MarkWest Operator Qualification program was revised (June 2007) to include provisions for training, as appropriate, as required in accordance with §195.505(h). Included is the MarkWest revised edition (June 2007) Operator Qualification program.

Item 7C

MarkWest's Operator Qualification Program (rev. January, 2005) does not include provisions to notify the Administrator or a state agency as required of §195.505(i).

Response

The MarkWest Operator Qualification program was revised (June 2007) to include provisions to notify the Administrator or a state agency as required in accordance with §195.505(h). Included is the MarkWest revised edition (June 2007) Operator Qualification program

SECTION 9 – CORROSION CONTROL

9.1. CATHODIC PROTECTION [49 CFR 195.563, 571, 551, & 573(b)]

9.1.1. Objective

The objective of this section is to prepare a written plan to periodically evaluate the integrity of MarkWest's pipelines in compliance with Federal regulations. The corrosion control program insures the continuous and uninterrupted operation of the pipeline facilities. Promptly notify a MarkWest Pipeline Safety Engineer if a safety-related condition is suspected.

9.1.2. General

Appendix 9.1 includes a discussion of galvanic corrosion. Appendix 9.2 includes a discussion of the effects of soil types on corrosion.

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.

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.

9.1.3. Qualifications for Supervisors [49 CFR 195.555]

The Area Plant 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 195.402(c)(3) for which they are responsible for insuring compliance.

9.1.4. Qualifications for Personnel [49 CFR 195.505]

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 G of 49 CFR 195.505 as amended on March 8, 2005.

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.

9.2. EXTERNAL CORROSION CONTROL [49 CFR 195.573]

49 CFR 195.557 requires submerged or buried pipelines to have coatings for external corrosion control. Likewise, 195.563 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.

9.2.1. Coatings and Cathodic Protection [49 CFR 195.401]

The following table lists the pipelines carrying hazardous materials on which coatings and/or Federal Regulation requires cathodic protection.

Construction Begun After	Pipeline Affected	Protection Required
March 31, 1970	Interstate pipeline, other than a low-stress pipeline	Coating Cathodic
July 31, 1977	Interstate offshore gather line, other than a low-stress pipeline	
October 20, 1985	Intrastate pipeline, other than a low-stress pipeline	Coating 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.

9.2.2. Monitoring External Corrosion [49 CFR 195.573]

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

Item	Description	Evaluation Frequency
Protected Pipeline – annual monitoring practical	Protected sections	Once per year, with intervals not exceeding 15 months
Protected Pipeline – annual monitoring impractical	Separately protected short sections of bare or ineffectively coated pipe	Once every three calendar years, with intervals not exceeding 39 months

Item	Description	Evaluation Frequency
Unprotected Pipeline – monitoring impractical	Mechanically coupled pipe Partial or wall-to-wall paving Common trench Stray current areas Excessive cover on pipeline	Once every three calendar years, with intervals not exceeding 39 months
Protected Pipeline – close interval survey	Meet objectives of NACE RP0169-2002, §10.1.1.3	Not more than two years after cathodic protection is installed Once every five calendar years, with intervals not exceeding 63 months. Time in between inspection intervals may be shortened if a deviation from the base line operating data is found. Deviations consist of areas of inadequate protection, stray current activity, and segments under construction.
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

9.3. <u>EXTERNAL PROTECTIVE COATINGS</u> [49 CFR 195.557, 559, & 561]

All new buried or submerged pipelines and all pipe replacements in existing lines shall be prepared and coated with an external protective coating such as "thin film epoxy", TGF-3, or any other acceptable coating. Please refer to **Appendix 9.1** *Pipeline Coating Chart* for approved coatings, applications and restrictions.

On existing pipelines uncovered for tapping, repairing or reconditioning, the area of repair, including added facilities, shall be cleaned until it is free of all dirt, oil, mill scale, rust, existing coating, or other foreign matter prior to applying the specified coating material. The coating material shall be chemically and physically resistant to the environment for which it is proposed. It shall be properly applied as to adhere to the metal surface and effectively resist underfilm migration of water, while being ductile enough to resist cracking. It shall be strong enough to resist damage due to handling and soil stress while remaining effective after the application of cathodic protection.

All electrically insulating type coatings shall have low moisture absorption, high electrical resistance, and be electrically inspected just prior to lowering of the pipe into the ditch. Any damage found must be repaired.

Coatings on pipe must be protected from adverse ditch conditions and supporting blocks to prevent damage. Precaution must also be taken to prevent damage to the coating if coated pipe is to be installed by boring, driving or other similar methods. Joints, fittings, and tie-ins shall be coated with materials compatible with the coating on the pipe. All pipe coating shall be inspected just prior to lowering the pipe into the ditch or submerging the pipe. Any damage discovered shall be repaired.

9.4. EXAMINATION OF PIPELINE [49 CFR 195.569]

At any time the pipeline is exposed, the pipeline will be inspected for condition of coating, evidence of corrosion, etc. If the line is cut or opened the internal surface shall be examined for evidence of corrosion. In each such instance, Form 124, Buried Pipeline Inspection Report, shall be prepared and forwarded to the Area Plant Manager or his/her designee.

If significant corrosion is found (i.e., over 29% of the wall thickness as measured with an Ultrasonic Thickness gauge), the remaining wall thickness will be evaluated using AGA/Battelle computer program, RSTRENG, to verify that the wall thickness is commensurate with the present MOP. The ASME/ANSI B31G manual calculation method is an acceptable alternative to RSTRENG in certain situations, such as when a detailed profile cannot be obtained.

If the remaining wall thickness is less than required wall thickness for the MOP of the pipeline, the MOP will be reduced to the pressure supported by the remaining wall thickness until repairs or replacements are made. If repairs are needed, further investigation is required to determine the extent of the corrosion.

If external corrosion requiring remedial action is found, an investigation will be performed circumferentially and longitudinally to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

If the results of the RSTRENG or ASME B31G analysis show that the remaining wall thickness is commensurate with the MOP, the line may remain in service at the current operating pressure.

If the coating is deteriorated, the deteriorated coating will be removed and the area recoated with an approved coating such as Trenton Wax Tape.

195.452(4)(i) – An operator must treat the following conditions as immediate repair conditions: (A) Metal loss greater than 80% of nominal wall regardless of dimensions (B) Calculation of remaining strength of pipe shows burst pressure less that the established MOP at the location of the anomaly.

Each segment of jurisdictional pipeline that has general corrosion and a remaining wall thickness less than that required for the MOP (1) must be replaced, or (2) the operating pressure reduced to the pressure that is commensurate with the strength of the pipe based on actual remaining wall thickness.

Segments of jurisdictional pipeline that have localized corrosion pitting where leakage might result must be repaired or replaced, or the operating pressure reduced to that pressure that is commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

If the pipeline operates at or above 20% of the pipe's specified minimum yield strength (SMYS) and incurs a metal loss not greater than 80% of the nominal wall, regardless of the dimensions, the strength of the remaining wall thickness may be determined by the using AGA/Battelle computer program RSTRENG to verify that the facility wall thickness is commensurate with the present MAOP. The ASME/ANSI B31G manual calculation method is an acceptable alternative to RSTRENG in certain situations, such as when a detailed corrosion profile cannot be obtained.

9.5. INTERFERENCE BONDS; DIODES AND REVERSE CURRENT SWITCHES [49 CFR 195.573(c)]

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 113, Critical Bond Report, for evaluation.

9.6. ELECTRICAL ISOLATION; INTERFERENCE CURRENTS [49 CFR 195.575 & 577]

9.6.1. 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 Area Plant 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 119, 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 Area Plant 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 120, Road Casing Evaluation, and forwarded to the Area Plant Manager or his/her designee, who shall maintain a record of shorted casings and of appropriate action taken.

9.6.2. 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 (See OM&E Section 9.15)

9.6.3. Inspection and Tests

The effectiveness of electrical insulating devices will be determined when the Annual Potential Survey in OM&E Section 9.12.1(a), 9.14.3, and 9.15.2 are 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 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.

9.7. OPERATION OF IMPRESSED CURRENT CATHODIC PROTECTION EQUIPMENT [49 CFR 195.573(c)]

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 114, Rectifier Report, and forwarded to the Area Plant Manager or his/her designee to be maintained for the life of the facility.

9.8. TEST STATIONS [49 CFR 195.567]

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 Corrosion Specialist. The approval will be documented using the approved MarkWest recordkeeping and retrieval system.

9.9. TEST LEADS [49 CFR 195.567]

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, as stated in OM&E Section 9.8.

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 113A, Test Station Report.

b) Install test lead(s) at foreign crossing(s) when the need has been verified by MarkWest's 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.

9.10. CORROSION MAPS/RECORDS [49 CFR 195.589]

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 195.569,195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

9.11. CORRODED PIPE [49 CFR 195.585 & 587]

MarkWest's personnel shall observe and review all corrosion and cathodic protection monitoring activities. If active corrosion is found, a thorough investigation of adjacent pipe will be made to determine the extent of the corrosion. Based on the manual calculation procedures in ASME B31G, the corroded pipe will be replaced with pipe which meets the pressure requirements of the pipeline, or the operating pressure will be reduced commensurate with the limits on maximum operating pressure specified in this manual.

9.12. EXTERNAL CORROSION MONITORING [49 CFR 195.573]

9.12.1. 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 127, Pipeline Annual Cathodic Protection Survey Report. These measurements shall include pipe-to-soil potentials at designated test stations and cased control facilities to insure proper operation. **If pipeline potentials are found to not meet the criteria as specified in NACE RP0169-2002 Section 6.2.2.1, corrective steps shall be taken to restore the structure to the proper degree of protection.**

Problems that may cause low potentials during an annual survey include but are not limited to:

- **Coating damage**
- **Electrical shorts**
- **Foreign crossings**
- **Depletion of anodes/ground beds**
- **Malfunctioning rectifier**

Below is a table containing response times for remediation of a low potential condition found during an annual survey.

90 day condition	180 day condition
Direct Intersect HCA Areas	Remote/Isolated Locations
Populated Areas	
High Traffic Roadways	

In the event that a condition cannot be corrected within the specified time frame due to the need for additional personnel, equipment, or materials, a remediation action plan will be developed to document justification for additional time requirements necessary to correct the condition.

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 114, 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 113, 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 113.

d) When a pipeline is uncovered for any reason, the Area Plant Manager or designee shall inspect the pipe and coating and report the results on Form 124, Buried Pipeline Inspection Report.

9.12.2. Documentation

a) All reporting shall be done on the Form 113, Critical Bond Report, Form 114, Rectifier Report, and Form 127, Pipeline Annual Cathodic Protection Survey Report. All data on these forms shall be reviewed and retained by the Manager of Plant Operations or his/her designee.

b) The Area Plant Manager or his/her designee shall maintain a permanent file of all corrosion leak repairs reported on Form 111, Operating Pipe Defect and Leak Report. These records shall be used to establish the need for remedial measures when appropriate.

9.13. INTERNAL CORROSION CONTROL [49 CFR 195.579]

MarkWest's personnel shall, at intervals not exceeding 7-1/2 months but at least twice each calendar year, examine monitoring equipment to determine the extent of any internal pipeline corrosion and document the findings on Form 126, 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 124, Buried Pipeline Inspection Report.

If internal corrosion is found, a thorough investigation of adjacent pipe will be made to determine the extent of the corrosion. After taking the wall thickness measurement, MarkWest will make manual calculations using the method in ASME/ANSI B31G or using the AGA/Battelle computer program RSTRENG to determine the required wall thickness for the MOP of the pipeline. If the actual wall thickness is less than the required wall thickness, the corroded pipe must be replaced with pipe which meets the pressure requirements of the pipeline, or the operating pressure must be reduced commensurate with the limits on maximum operating pressure specified in this manual.

9.14. ATMOSPHERIC CORROSION CONTROL [49 CFR 195.581 & 583]

9.14.1. 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.

9.14.2. General [49 CFR 195.581]

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.

9.14.3. Monitoring [49 CFR 195.563, 583, & 585]

All aboveground facilities will be inspected for atmospheric corrosion at least once every three calendar years, not to exceed 39 months, for onshore facilities (Form 104, Atmospheric Corrosion Control Inspection).

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, as in OM&E Section 9.14.2.

The remaining wall thickness of facilities found to have atmospheric corrosion will be evaluated using manual calculation methods described in ASME/ANSI B31G or by computer procedures using AGA/Battelle RSTRENG program to verify the facility's Maximum Allowable Operating Pressure (MAOP).

If the remaining wall thickness is commensurate with the required wall thickness, then the facility will be cleaned and recoated with a proper coating. Remedial action for atmospheric corrosion must be performed within one year of discovery. If the wall thickness is not commensurate with the required wall thickness, then the facility will be replaced or the MOP will be reduced to the pressure supported by the remaining wall thickness.

9.15. ROAD CASING

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

9.15.1. 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 120, Road Casing Evaluation, shall be completed if a short is found.

9.15.2. Testing and Remedial Measures for Existing Road and Railroad Crossings.

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

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

9.15.3. 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.

   - 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.

   - 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.

   - 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.

- 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

- 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.

- 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

- 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.

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

- 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.

- 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:

APPENDIX 9.1

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).

APPENDIX 9.2

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.

SECTION 5 – EMERGENCIES

5.1. EMERGENCIES [49 CFR 195.402(e)]

5.1.1. General

Emergency: A hazardous (potentially dangerous) situation near or directly involving a pipeline. Hazardous situations include, but are not limited to:

a) (Reported or actual) significant amounts of escaping HVL's in any location
   - vapor cloud
   - NGL stream
   - frozen ground
b) Fire or explosion near or directly involving a pipeline
c) Natural disaster (flood, tornado, earthquake, etc.)
d) Terrorist acts (bomb threats or sabotage, etc.)

In order to prevent injury to employees or to the public, or to prevent serious damage to property, the first employee to become aware of the emergency shall take the following action:

a) Ensure the safety of the affected public
b) Contact SCADA control operator at (877) 675-9378 and depending on the segment affected, advise to shut down discharge pump(s) and close MOV stations.
c) Take other appropriate action as necessary.

MarkWest employees responding to an emergency will have various equipment and tools on hand to include but not limited to:

- Flame Retardant Clothing
- Fire Extinguishers
- Pipeline Locators
- Gas Detectors
- Wrenches
- Sockets
- Multimeters
- Shovels
- Temporary Pipe Clamps
- Coating
- Caution Tape
- Wind Direction Detection Material (windsock/flag, etc)
- Weather Monitoring Device(s)
- Radio and Cell phone Communications

5.1.2. Procedure for Emergency and/or Odor Identification

SCADA Control will receive the majority of reports of pipeline leaks, odors, or other emergencies through the 24-hour emergency number or by emergency dispatch (911). The person receiving a leak report will record the following information (See Form 121, Pipeline Emergency Log):

a) Request that persons stay away from leak or danger area
b) Date & time
c) Caller's name and phone number
d) Nature of emergency
e) Location of emergency

f) County, Town and State
g) Nearest road or street address
h) What did the caller see, hear or smell
i) Is there a fire or vapor cloud
j) Name of the person you called including the time
k) Name of the person you paged, including the time

In the event another facility associated with the Appalachian Liquid Pipeline System receives a report, the operator shall complete a Pipeline Emergency Log and immediately contact SCADA Control and outside emergency personnel as required.

5.1.3. Response Procedures for Reported Odor Complaint / Suspected Leak

1. After initial complaint, SCADA Control will contact pipeline personnel and advise of location of odor complaint.
2. Pipeline personnel will travel to location and investigate the odor complaint.
3. SCADA Control will notify other facilities associated with the Appalachian liquid pipeline system of the odor complaint. During this notification, all SCADA operators will continually monitor the SCADA systems in collaboration.
4. Pipeline personnel will communicate results of the odor complaint investigation to SCADA Control and advise of further action required.
5. **After two independent odor complaints, depending on the segment affected, SCADA Control will immediately shut down discharge pump(s) and close MOV stations.**
6. If the pipeline is shutdown, it shall not be returned to service until a proper accident investigation for the emergency condition is conducted and SCADA Control receives approval from Pipeline Management or authorized/designated pipeline personnel.

NOTE: This plan of action is based on SCADA Control receiving the first call. If another facility associated with the Appalachian Liquid Pipeline System receives the first call, then they must immediately contact SCADA Control to commence the proper plan of action.

5.1.4. Response Procedures for Fire / Explosion or Reported Leak / Rupture Incident

1. On the first report of incident, depending on the segment affected, SCADA Control will immediately shut down discharge pump(s) and close MOV stations.
2. If necessary, SCADA Control will contact emergency response personnel & report conditions.
3. SCADA Control will notify pipeline personnel when notice of an accident/incident is received.
4. SCADA Control will continually inform other facilities associated with the Appalachian Liquid Pipeline System of updated news about the incident.
5. MarkWest will proceed with an Accident Investigation.
6. The pipeline shall not be returned to service until a proper accident investigation for the emergency condition is conducted and SCADA Control receives approval from Pipeline Management or authorized/designated pipeline personnel.

NOTE: This plan of action is based on SCADA Control receiving the first call. If another facility associated with the Appalachian Liquid Pipeline System receives the first call, then they must immediately contact SCADA Control to commence the proper plan of action.

5.1.5. Responding to an Accident

a) MarkWest and emergency response personnel shall report to site and take necessary action to protect life and to eliminate the hazardous situation.

- Evacuate people to a safe distance and see that anyone injured in connection with the emergency receives prompt first aid and medical attention.
- Take necessary steps to block off the hazardous area to traffic and unauthorized persons in order to guard against accidental ignition and possible injuries.
- Request assistance from the fire department, ambulance service, police, and other public agencies (emergency telephone numbers shall be updated and reposted annually).
- Employee shall set up communications with the Area Plant Manager or his/her designee in order to give the location and evaluation of the emergency. Further instructions or assistance can be determined during this collaborative meeting.
- Attempt to eliminate or control the release of HVL's.
- **All employees responding to emergencies shall keep an emergency log to include times, witnesses, emergency response, equipment failures and equipment modifications. Emergency logs shall be provided to the Pipeline Manager.**

b) After arrival at the emergency location, management will survey the situation, take necessary action to control the area, and formulate a plan for repairing damages and placing the line back into service.

- A combustible gas indicator or "flame ionization gas detector" shall be used by a qualified MarkWest employee to determine the concentration of HVL vapors in the area. In the instance where flammable highly volatile liquids are present, a qualified MarkWest employee shall continually monitor the area to determine the extent and coverage of the vapor cloud and determine the hazardous areas.

  i. All available MarkWest pipeline personnel will be dispatched to the emergency location.

  ii. MarkWest pipeline personnel will first survey the site to determine the localized hazardous area by visual confirmation of the vapor cloud. Initial measurements will be taken such as wind speed, wind direction, temperature, humidity, elevation, and cloud cover with both a wind direction detection device and weather monitoring device and will be documented within FORM 105 - *Onsite Leak and Emergency Situation Evaluation.* Other information such as estimated spill volume and time of release will also be documented on this form.

  iii. If necessary, MarkWest pipeline personnel will be dispatched around the outside of the visually confirmed hazardous area with gas detection equipment to determine the extent and coverage of the vapor cloud and hazardous area.

  NOTE: The steps listed above will be performed in coordination with emergency response personnel and Incident Command including the collection of information obtained during the assessment.

- Prior to any welding, a combustible gas indicator or "flame ionization gas detector" is to be used and frequent checks shall be made while the work is in progress in order to determine if the area remains safe as work progresses. The ditch work area shall be "flushed" before commencing welding operations.
- Maintain contact with Area Plant Manager or his/her designee in order to keep management informed of progress.

- Maintain contact with the fire department, ambulance service, police, and other public officials, requesting their help if needed.
- Assist emergency response personnel at the location in all aspects necessary based on the emergency at hand and the capabilities of MarkWest personnel.
- Advise emergency response personnel and incident command on the characteristics of the product.

Below is a table detailing volume release and HCA impact information pertaining to each segment within the Appalachian Liquid Pipeline System. Please refer to Procedure IM-001 *Volume Release and HCA Impact* and Appendix D within the Pipeline Integrity Management Program for additional information.

	COMPARISON SCENARIO	PIPELINE SEGMENT		
	All 'Heavy' with evaporating pool	MAYTOWN	SILOAM	TRANSANDY
VAPOR CLOUD EXPLOSION HAZARD				
Distance to 'Some Damage to Home Ceilings, 10% Window Breakage' from shock wave overpressure	3,794 feet	6,516 feet	6,156 feet	6,213 feet

Below is a table containing the total volume of product between facilities and each motor operated valve site once the product has been contained through valve closure.

LOCATION			DISTANCE		PIPE INFORMATION		TOTAL VOLUME
					Diameter	Volume per inch	
Maytown	to	M-MOV-1	20,359 ft	3.86 mi	4 in	11.4969 in³	12,159.21 gallons
M-MOV-1	to	M-MOV-2	28,100 ft	5.32 mi	4 in	11.4969 in³	16,782.45 gallons
M-MOV-2	to	M-MOV-3	5,552 ft	1.05 mi	4 in	11.4969 in³	3,315.88 gallons
M-MOV-3	to	M-MOV-4	47,232 ft	8.95 mi	4 in	11.4969 in³	28,208.85 gallons
M-MOV-4	to	M-MOV-5	49,708 ft	9.41 mi	4 in	11.4969 in³	29,687.62 gallons
M-MOV-5	to	M-MOV-6	44,796 ft	8.48 mi	4 in	11.4969 in³	26,753.97 gallons
M-MOV-6	to	M-MOV-7	21,794 ft	4.13 mi	4 in	11.4969 in³	13,016.25 gallons
M-MOV-7	to	M-MOV-9	1,819 ft 26,203 ft	0.34 mi 4.96 mi	4 in 5 in	11.4969 in³ 18.1937 in³	25,851.58 gallons
M-MOV-9	to	M-MOV-10	27,149 ft	5.14 mi	5 in	18.1937 in³	25,659.29 gallons
M-MOV-10	to	M-MOV-11	65,087 ft	12.33 mi	5 in	18.1937 in³	61,515.58 gallons
M-MOV-11	to	T-MOV-1	30,624 ft	5.80 mi	6 in	29.4647 in³	46,874.13 gallons
T-MOV-1	to	T-MOV-2	32,736 ft	6.20 mi	6 in	29.4647 in³	50,106.83 gallons
T-MOV-2	to	T-MOV-3	29,568 ft	5.60 mi	6 in	29.4647 in³	45,257.78 gallons
T-MOV-3	to	T-MOV-4	35,904 ft	6.80 mi	6 in	29.4647 in³	54,955.88 gallons
T-MOV-4	to	T-MOV-5	19,008 ft	3.60 mi	6 in	29.4647 in³	29,094.29 gallons
T-MOV-5	to	T-MOV-6	30,624 ft	5.80 mi	6 in	29.4647 in³	46,874.13 gallons
T-MOV-6	to	S-MOV-3	43,986 ft	8.33 mi	6 in	29.4647 in³	67,326.46 gallons
S-MOV-3	to	S-MOV-4	30,307 ft	5.74 mi	6 in	29.4647 in³	46,388.92 gallon
S-MOV-4	to	S-MOV-5	13,017 ft	2.47 mi	6 in	29.4647 in³	19,924.26 gallon
S-MOV-5	to	S-MOV-6	43,283 ft	8.20 mi	6 in	29.4647 in³	66,250.43 gallon
S-MOV-6	to	S-MOV-7	27,293 ft	5.17 mi	6 in	29.4647 in³	41,775.59 gallon
S-MOV-7	to	Siloam	65,124 ft	12.33 mi	6 in	29.4647 in³	99,681.00 gallon

Information within the 2 tables above may be beneficial to the emergency responders and Incident Command and will be made available to them in the event of an emergency.

OM&E Manual Section 15, *Material Safety Data Sheets* can be consulted for the characteristics of the product contained within the pipeline.

c) If additional personnel or equipment is required, they shall be secured from outside contractors near the incident. All personnel used in this area will be under the supervision of MarkWest during the course of the operation.

d) Pipeline systems shut-in because of emergencies shall be placed back in service when the following conditions are met:

  - Facilities associated with the Appalachian Liquid Pipeline system are operational.
  - The integrity of the pipeline has been verified.

e) The pipeline manager in conjunction with the Area Manager is responsible for containment and cleanup of a hazardous substance spill.

5.1.6. Response to Small Leaks

Leaks where very small volumes of HVL's are being lost, causing neither a hazardous situation nor an odor problem.

a) Notify management immediately upon discovery
b) MarkWest pipeline personnel to begin repair work as soon as possible
c) Monitor for possible development of hazardous situation until repair completed
d) Complete repair report

5.1.7. Intentional Ignition of HVL's

During leak repairs and excavation activities, vapors may have to be ignited (if line cannot be properly purged) to eliminate the potential for flash fire. A flare gun (12 gauge) will be used to ignite vapors.

Intentional ignition of HVL's may also have to be accomplished during line blow-off operations due to atmospheric conditions. In this event, a standpipe assembly will be installed on the pipeline to ensure a controlled burn.

Safety procedures for intentional ignition of HVL's:

a) Notify affected public
b) Notify local emergency officials
c) Check location where flare is ignited with LEL meter to assure area is safe
d) Stand upwind from leak when igniting HVL's
e) Wear flame retardant coveralls
f) Ensure fire extinguisher is available

5.1.8. Emergency Call List

MarkWest has an Emergency Call List used to locate Company personnel and management in case of an emergency. This Emergency Call List is posted where it can be easily seen within the control rooms of all facilities associated with the Appalachian Liquid Pipeline System. At a minimum, the emergency call list includes the names and telephone numbers of the following:

a) Fire Department+

b) Police and Sheriff's Departments
c) Ambulance
d) Hospitals/Medical Facilities
e) Doctors
f) Appropriate County Officials
g) Qualified Contractors
h) National Response Center

5.1.9. Accident Investigation

MarkWest shall be responsible for any investigation that may be required in connection with any leak or test failure. The investigation shall include a review of employee activities to determine if procedures used during the emergency were adequate or if corrective action is required.

MarkWest shall, in the case of leaks, review operating and maintenance records for the section of pipeline involved.

Based on preliminary findings, MarkWest shall determine the need for metallurgical or other more detailed investigation.

Upon completion of the investigation, a report shall be prepared outlining the probable cause of failure, with recommendations of remedial action if the investigation findings so warrant.

5.1.10. Telephonic Reporting [49 CFR 195.52]

OPS Reporting - In the event of a reportable accident as defined in OM&E Section 4.1, the Area Manager or his/her designee shall telephone the National Response Center at (800) 424-8802. <u>NOTE: OPS requires a response within two hours from the time of the accident</u>. This Telephone Report should be given at the earliest practicable moment following discovery of the accident and should include the following:

a) Date and time of report
b) Name and phone number of person reporting accident
c) Name and address of operating company
d) Phone number of company
e) Designate whether leak or rupture
f) Whether or not a fire occurred
g) Type of facility
h) Date and time of accident
i) Name of line or plant
j) Location of accident - approximate Station No. or M.P.
k) Location of accident - County and State
l) Number of injuries or fatalities
m) Comments: The extent of injuries and fatalities, if any, and all other significant facts known then to the Company relevant to the cause of the accident or the extent of the accident or the extent of damages. A copy of the telephonic message shall be maintained as a record.

5.1.11. Written Accident Reports for the Department of Transportation [49 CFR 195.50, 52, & 54]

If an accident (defined in OM&E Section 4.1) requires a report, then as soon as practicable, but not later than 30 days after discovery of accident, the Operator shall prepare and file an accident report on **<u>DOT Form 7000-1</u>**. Any changes or additions to the information reported on the original DOT Form 7000-1 shall be filed on a supplemental report within 30 days.

5.2. FIREFIGHTING EQUIPMENT [49 CFR 195.430]

The main function and objective is to set forth requirements for maintaining fire extinguishers and other fire fighting equipment in a state of readiness at all times.

The Area Plant Manager or his/her designee is responsible for maintaining the fire extinguishers and other equipment.

On a monthly basis, all fire extinguishers and gas detector equipment will be inspected by a qualified employee of MarkWest. Records of these inspections shall be maintained for each fire extinguisher. (See Form 106, Inventory Audit)

All MarkWest vehicles normally used on the pipeline will be equipped with fire extinguishers. **All pump stations will be equipped with fire extinguishers.**

5.3. LIAISON WITH EMERGENCY RESPONDERS [49 CFR 195.440 & 402(c)(12)]

MarkWest will assure that education and training with emergency agencies is completed annually. MarkWest sponsors meetings with agencies through SafetyComm Solutions. Information presented during training meetings includes the following information:

a) Map of MarkWest pipeline

b) Type of emergencies that might occur involving these facilities:
   - Pipeline Rupture
   - Fire/Explosion
   - Leak
   - Sabotage

c) How to recognize HVL emergencies
   - Flow of liquid
   - Distinct smell of hydrocarbon
   - Hissing or spewing sound
   - Low lying fog
   - Frozen area

d) What to do in the Event of an Emergency
   - Secure the area
   - Evacuate people
   - Take steps to prevent ignition
   - Contact MarkWest
   - Do not operate MarkWest valves

APPENDIX 9.1

PIPELINE COATING CHART

NOTE: This Pipeline Coating Chart contains information on specific external coatings that are approved for use on any segment within the Appalachian Liquid Pipeline System.

COATING PRODUCT	MANUFACTURER	PPE REQUIRED	APPLICATIONS/RESTRICTIONS
SCOTCHKOTE 226P HOT MELT PATCH COMPOUND	**3M**	SAFETY GLASSES/SIDE SHIELDS NOMEX GLOVES	TOUCHUP, PATCHING AND REPAIR OF FUSION BONDED EPOXY COATING. MINOR DAMAGE TO FBE COATING PINHOLES IN FBE COATING NICKS IN FBE COATING EASILY APPLIED AND QUICK SETTING FOR INSTALLATION & HANDLING
WAX-TAPE #1	**TRENTON**	NEOPRENE GLOVES	APPLIED TO UNDERGROUND PIPE CAN BE USED ON WET AND IRREGULAR SURFACES COUPLINGS, VALVES, FITTINGS, WELD CUTBACKS, CAD WELDS NON-HAZARDOUS PETROLEUM BASED PRIMER MUST BE APPLIED PRIOR TO WAX-TAPE APPLICATION CAN BACKFILL IMMEDIATELY AFTER APPLICATION
WAX-TAPE PRIMER	**TRENTON**	NEOPRENE GLOVES	WAX COATING PRIMER USED ON PIPE PRIOR TO WAX-TAPE # 1 APPLICATION NON-HAZARDOUS PETROLEUM BASED
FILL-COAT #2	**TRENTON**	NEOPRENE GLOVES	COLD INSTALLED INERT DIELECTRIC MATERIAL FOR FILLING CASINGS DISPLACES WATER PREVENTS WATER FROM ENTERING CASING PREVENTS GALVANIC CORROSION AND 'WATER' SHORTS NON-HAZARDOUS PETROLEUM BASED
PROTAL 7200 7200 'A' & 7200 'B' - REPAIR CARTRIDGE	**DENSO**	NEOPRENE/BUTYL GLOVES CHEMICAL GOGGLES FULL FACE SHIELD	TOUCHUP, PATCHING AND REPAIR OF FUSION BONDED EPOXY COATING. MINOR DAMAGE TO FBE COATING PINHOLES IN FBE COATING NICKS IN FBE COATING 2 PART CARTRIDGE BASED APPLICATION. MUST BE MIXED PRIOR TO APPLYING TO PIPE
WRAPID SLEEVE KLS SHRINKWRAP SLEEVE	**CANUSA**	SAFETY GLASSES FIRE RETARDANT CLOTHING LEATHER GLOVES W/LONG SLEEVES	CORROSION PROTECTION OF BURIED AND EXPOSED STEEL PIPELINES WHEN HEATED, BONDS TO FBE COATING AND STEEL USED FOR PIPELINE JOINTS, GIRTH WELDS AND TIE-INS NO PRIMER REQUIRED
FUSION BONDED EPOXY COATING 102 GREEN	**3M**	**ONLY REQUIRED WHEN GRINDING/SANDING** INDIRECT VENTED GOGGLES NEOPRENE/NITRILE GLOVES DUST MASK	COATING USED FOR NEW PIPE. COMES PRE-APPLIED ON PIPE 12-14 MILS THICKNESS
HANDY CAP COLD APPLIED CADWELD COVER	**ROYSTON**	SAFETY GLASSES OR GOGGLES GLOVES	DESIGNED FOR CATHODIC PROTECTION LEADS ON PIPELINE FOR ANNODE AND TEST LEAD CONNECTIONS REQUIRES ROYBOND 747 PRIMER ADHESIVE PRIOR TO APPLICATION
ROYBOND 747 RUBBER RESIN ADHESIVE	**ROYSTON**	SAFETY GLASSES OR GOGGLES SOLVENT RESISTANT GLOVES VENTILATION	RUBBER RESIN ADHESIVE PRIMER USED ON CADWELD AND PIPE PRIOR TO APPLICATION OF HANDY CAP CADWELD COVER

SECTION 7 – OPERATIONS

7.1. NORMAL OPERATIONS [49 CFR 195.402(c)]

The purpose of this section is to discuss the activities and operations of the facilities covered by this manual that are considered normal and to establish guidelines by which the liquid pipeline system is operated and maintained on a daily basis.

a) Permanent files have been set up in the pipeline operations office located at the Kenova, Maytown, and Siloam Plants. These files are to contain all available construction records, and maps and operational data and guidelines for safe operations of the facilities.

b) The Operations and/or Maintenance and/or Safety Supervisor is responsible for collecting pertinent data and reporting all accidents and safety-related conditions.

c) The operation, maintenance and repairs of the pipeline system shall be in accordance with this manual.

d) Due to the nature of the liquid carried by the subject pipeline system, the entire system requires an immediate response by the Operator, MarkWest, to prevent hazards to the public if the facilities failed or malfunctioned. The level of failure or malfunction of the facilities will determine the level of reaction of the Operator.

e) The continued efforts of the Operator to monitor the facilities and their daily operation, operate the facilities in a safe manner within the established guidelines, maintain the facilities to prevent failures and make any replacements with equal equipment are intended to minimize the potential for hazards and the possibility of their occurrence or reoccurrence.

f) MarkWest shall be a member of current ONE CALL systems (KY and WV) in an effort to prevent the excavation of a MarkWest pipeline without a MarkWest representative on the site. See OM&E Section 7.18 for further details.

g) Employees of MarkWest that come in contact with the contractors and excavators in the area are sensitive to the possibility of damage to the pipeline facilities. Form 116, Request to Locate Pipeline or Notification of Planned Excavation Activities, is completed when MarkWest personnel are contacted about planned excavation activities. See OM&E Section 7.18 for further details.

7.2. SCADA OPERATIONS

7.2.1. SCADA Introduction

MarkWest has implemented a new automated main line supervisory control and data acquisition (SCADA) system on the Appalachian Liquid Pipeline System (ALPS). This system is also known as a Computational Pipeline Monitoring System (CPM) per API-1130. The system monitors the pressure in the pipeline and at the discharge pumps to discover pipeline leaks. If the system senses low pressure in the line, it automatically shuts in sections of the pipeline in turn shutting down the Maytown discharge pump. Alternately, the operator at SCADA Control can shut down sections of the pipeline or shut down discharge pumps (in the event of an emergency) using remote control. The ability to isolate sections of the pipeline automatically and remotely by SCADA Control increases public safety in the event of a pipeline leak due to natural, accidental, or intentional causes. It also allows monitoring of the pipeline on a real time basis and archiving of the pipeline operating data.

The SCADA system includes automated, motor operated valves (MOVs) at fifteen locations along the pipeline, pressure sensing at the MOV stations, satellite transmission of signals from the MOV stations to SCADA Control, and software at the valve station PLCs and SCADA Control to open and close the automated valves.

The discharge pump at the Maytown plant facility has also been incorporated into the SCADA system for active monitoring of the pump discharge pressure, and to include the capability of pump shutdown in the event of a motor operated valve closure.

The Host computer and software has been placed at the Kenova Extraction Plant facility in Kenova, West Virginia. This SCADA Control site provides 24 hour, 7 days a week operator coverage for monitoring the pipeline conditions via the Pipeline SCADA System PC outputs, console graphics and alarms. SCADA Control will communicate via satellite to each remote valve station location, discharge pump, and SCADA Monitoring sites. SCADA Control will have control capability and the SCADA Monitoring sites will view all of the Host site console screens with any status changes, warning and alarm conditions, and any actions taken from the SCADA Control system.

There are eleven (11) new main line gate valve stations installed on the Maytown to Ranger segment of pipeline. Ten of these stations have automated and electric motor operated valves (MOVs). There are (5) MOVs installed at previously existing flow station sites on the Kenova to Siloam pipeline. (MOVs for the Transandy or Ranger to Kenova pipeline will be planned and installed in a future year). Since these MOVs can be remotely operated they have been designated as Emergency Flow Restricting Devices (EFRDs) per Part 195.452(i)(4).

7.2.2. Pressure Monitoring

Each of the new MOV valve/flow stations have two (2) pressure transmitters, one installed immediately upstream and one immediately downstream of the MOV. These transmitters will provide pressure information continuously via the SCADA remote terminal unit (RTU; SCADAPackLP by Control Microsystems) and satellite communications to the SCADA Control computer. The transmitter readings are available on the SCADA Control and SCADA Monitoring screens.

The discharge pressure of the Maytown pump has also been incorporated into the SCADA system. This pressure reading is taken from the current plant automation system via the SCADA remote terminal unit (RTU; SCADAPack 100 by Control Microsystems) and satellite communications to the SCADA Control computer. The transmitter readings are available on the SCADA Control and SCADA Monitoring screens.

7.2.3. Remote Capabilities

The MOV valves on the pipeline have remote open and close capability from the Host SCADA system (ClearSCADA by Control Microsystems) via operator command. Specifically, the Host will monitor and control the following physical points at each remote MOV site. The following points are monitored by the SCADA:

a) RTU input for pressure transmitter upstream of MOV
b) RTU input for pressure transmitter downstream of MOV
c) RTU input for MOV full open position
d) RTU input for MOV full close position
e) RTU input for AC power confirmation
f) RTU input for MOV local or remote selector position
g) RTU input for battery voltage
h) RTU input for board temperature

The following points are controlled by the SCADA:

a) RTU output for open valve relay

b) RTU output for close valve relay

All of the above listed points will be represented by tags in the Host system and monitored and displayed through the SCADA application.

The valve position control will be accomplished in four ways. The first two methods are accomplished at the MOV site; the other two are accomplished at the Host SCADA PC.

[illegible]	[illegible]	OPERATION
1	**LOCAL MODE AT MOV**	• At the MOV, position the LOCAL/REMOTE selector in the LOCAL position. • Turn the OPEN/CLOSE selector to the desired position and the valve will proceed to that position. **Note**: When the selector at the valve is in the LOCAL position the valve CANNOT be controlled by the SCADAPack PLC or SCADA Control.
2	**REMOTE MODE AT MOV SITE** (SCADAPack PLC/RTU)	• At the MOV, position the LOCAL/REMOTE selector in REMOTE position. • From the local display at the MOV site SCADAPack PLC, change the PLC from AUTOMATIC to MANUAL mode by pressing the proper keypad function key and entering the password. • After putting the PLC in MANUAL mode, select the function OPEN. • After selecting OPEN, the valve will proceed to open. • After selecting CLOSE, the valve will proceed to close. **Note**: The MANUAL mode of the SCADAPack PLC CAN be changed to AUTOMATIC mode by SCADA Control.
3	**MANUAL MODE AT SCADA Control**	• At the MOV, position the LOCAL/REMOTE selector in REMOTE position. • At SCADA Control, the SCADA screen allows the operator to select MANUAL or AUTOMATIC mode. **Note**: You must have proper security credentials to operate the selector screen. • Select MANUAL. The SCADA Control RTU will send a signal to the remote SCADAPack PLC changing the PLC from AUTOMATIC to MANUAL mode. The dialog box to open or close the valve will appear. • Select OPEN. The SCADA Control RTU will send a signal to the remote SCADAPack PLC and the MOV will open. When the valve trips the proximity switch at the open position, the movement will be confirmed on the SCADA Control screen. • Select CLOSE. The SCADA Control RTU will send a signal to the remote SCADAPack PLC and the MOV will close. When the valve trips the proximity switch at the closed position, the movement will be confirmed on the SCADA Control screen.
4	**AUTOMATIC MODE AT MOV SITE** (SCADAPack PLC/RTU) **& SCADA Control**	• At the MOV, position the LOCAL/REMOTE selector in REMOTE position. • At SCADA Control, the SCADA screen allows the operator to select AUTOMATIC or MANUAL. **Note**: You must have proper security credentials to operate the selector screen. • Select AUTOMATIC. The SCADA Control RTU will send a signal to the remote SCADAPack PLC changing the PLC from MANUAL to AUTOMATIC mode. • In AUTOMATIC mode, the SCADAPack PLC senses the pressure at both pressure transmitters upstream and downstream of the MOV. • IF the pressure at <u>both</u> pressure transmitters goes below a pre-set minimum site MOV pressure, THEN the PLC will command the MOV to close. • The SCADAPack RTU will signal the SCADA Control computer of the action. This will cause a notification at the SCADA Control PC via audible and visual alarms. • IF the pressure at <u>one</u> of the two pressure transmitters rises above the minimum site MOV pressure, THEN the SCADAPack RTU will send a signal to SCADA Control that will allow the SCADA Control operator to RESET the SCADAPack PLC and remotely open the MOV.

The following screen notifications will take place at the SCADA Control and SCADA Monitoring PC consoles for the motor operated valves:

a) AC power failure
b) Backup batteries voltage
c) MOV local or remote selector mode
d) MOV closed
e) MOV open
f) PLC automatic or manual mode
g) Low pressure warning (approaching MOV site minimum psig, specified for each location)
h) Low-Low pressure alarm (below MOV site minimum psig, specified for each location)
i) High pressure warning (approaching MOV site maximum psig, specified for each location)
j) High-High pressure alarm (above MOV site maximum psig, specified for each location)
k) Pressure clear above MOV site minimum psig acknowledge and valve open reset permissive
l) Pressure transmitter high or low, out of range
m) Communication failures

The Maytown pump has remote shutdown capability by the Host SCADA system (ClearSCADA by Control Microsystems) automatically via a valve closure or by operator command (only in the event of an emergency). Specifically, the Host will monitor and control the following physical points at each discharge pump that has been incorporated into the SCADA system. The following points are monitored by the SCADA:

a) RTU input for pressure of discharge pump via plant automation system
b) RTU input for status of pump (running or shutdown)
c) RTU input for board temperature

The following points are controlled by the SCADA:

a) RTU output for pump shutdown

All of the above listed points will be represented by tags in the Host system and monitored and displayed through the SCADA application.

The following screen notifications will take place at the SCADA Control and SCADA Monitoring PC consoles for the Maytown discharge pump:

a) Pump status (running or shutdown)
b) High-High pressure alarm (above pump maximum psig)
c) Pump shutdown bypass (engaged or disabled)
d) Communication failures

7.2.4. Detection of Warning & Alarm Conditions

A pressure warning or alarm condition will alert the SCADA Control Operator on duty via audible and visual alarms and an alarm log status screen on the SCADA Control console.

a) The low pressure and high pressure set point warnings will alert SCADA Control via visual and audible alarms.

b) The low-low and high-high pressure condition alarms will also alert SCADA Control via visual and audible alarms.

Upon hearing the alarms, the SCADA Control operator on duty should review the situation on the SCADA PC console and the SCADA system alarm summary log. See OM&E Section 7.17, Abnormal Operation.

7.2.5. Alarm Condition/MOV Functionality

As stated previously, the SCADA RTU at each remote MOV site will close the valve if the pressure at both pressure transmitters goes below the alarm set point for MOV site minimum psig specific to each location, providing a fail-safe line break capability.

a) Upon shutting the valve, the RTU will notify SCADA Control of the action and notification will take place on the SCADA Control and SCADA Monitoring PC consoles.

b) The SCADA Control system will then automatically shut down the Maytown discharge pump, and close the immediate downstream and then the immediate upstream MOV and notify the Control and Monitoring PCs.

If the pressure at either transmitter at a MOV site goes above the specified MOV site maximum psig, an alarm will also be indicated at the SCADA PC consoles. The initial set points for the minimum and maximum pressure limits at each MOV site will be determined from transient hydraulic modeling of the pipeline system.

Note: The pressure transmitters are set to fail range high to eliminate automatic low-low MOV closure due to vandalism or sabotage, to avoid pumping against a closed MOV without indication of a leak.

SCADA Password Hierarchy

The purpose of this section is to discuss the password environments and hierarchy regarding authority levels in the ALPS Pipeline SCADA system. Password credentials ensure that the training and authority are appropriate for the task performed.

Host SCADA PC		
Environment	Capability	Personnel
1) **Opr**	♦ Utilize Full SCADA Functionality ♦ Adjust Timer, 10 to 60 minutes only	♦ All SCADA Control Operators ♦ All ALPS Pipeline Technicians
2) **Eng**	♦ Adjust Pressure Warning & Alarm Set Points ♦ Adjust Timer, 0 to 60 minutes (0 min. = SCADA will stay in MANUAL mode)	♦ Jamie Adams, EH&S Technician ♦ Keith Anderson, Senior Plant Technician ♦ Rick Ferguson, Plant Technician A ♦ Carl Hunt, Pipeline Technician A
4) **View**	♦ View and Monitor the SCADA Status, Trends and Alarms	♦ All SCADA Monitoring facilities excluding SCADA Control.
MOV Site PLC/RTU		
1) **Control** (F3 on Key Pad)	♦ Utilize Full SCADA Functionality ♦ Adjust Pressure Warning & Alarm Set Points	♦ All ALPS Pipeline Technicians
2) **Config** (F4 on Key Pad)	♦ Software Configuration and Changes	♦ All ALPS Pipeline Technicians

7.2.6. ALPS SCADA System Implementation – Phase 2

The Phase 2 SCADA System Implementation (almost complete as of October 2006) includes the following functionalities:

a) Pump running status screens will be functional at the Kenova Host & Siloam and Maytown SCADA PCs.

b) The Host SCADA application will automatically shutdown the Kenova and/or the Maytown plant pipeline pumps via I/O to the existing plant control systems. These shutdowns will occur due to a low-low or high-high set point alarm received from any of the pipeline MOV sites.

7.3. STARTUP PROCEDURES

This section describes the start-up of the pipeline following a normal shutdown.

There are eleven block valve stations on the Maytown-to-Ranger pipeline. At ten of the stations, the critical block valve is a Motor Operated Valve (MOV) that can be remotely operated by SCADA Control. At one station, the critical block valve (HV-8) is a manual block valve that can only be operated locally. There is one critical block valve (HPSD-15) on the Ranger-to-Kenova pipeline (also called the Transandy pipeline) at the ANSI 1500# to ANSI 600# piping specification boundary. In addition, there are five block valve stations on the Kenova-to-Siloam pipeline. At each station, the critical block valve is an MOV.

The tag numbers of the MOVs at the flow stations on the Maytown-to-Ranger pipeline are preceded by the letter "M" (e.g., M-MOV-1), and those on the Kenova-to-Siloam pipeline, by the letter "S" (e.g., S-MOV-3). The MOV stations are:

Maytown-to-Ranger	Kenova-to-Siloam
M-MOV-1	S-MOV-3
M-MOV-2	S-MOV-4
M-MOV-3	S-MOV-5
M-MOV-4	S-MOV-6
M-MOV-5	S-MOV-7
M-MOV-6	
M-MOV-7	
M-MOV-9	
M-MOV-10	
M-MOV-11	

Refer to OM&E Section 13, Map of the Pipeline with the MOV Locations.

a) Prior to startup, the SCADA Control operator shall verify with the pipeline technician that all relief valves equipped with manual blocks for test purposes have been sealed open with black tie-wraps.

b) Prior to startup, the SCADA Control operator shall verify with the Maytown plant operator that:

- ♦ The High Pressure Shutdown (PSH-598) on the Product Storage and Delivery Pump (ESE-403, ESE-405) has been set to 1120 psig.
- ♦ The High Pressure and High-High Pressure alarms have been set to 1000 and 1067 psig, respectively.
- ♦ The Low Pressure and Low-Low Pressure alarms have been set to 725 and 656 psig, respectively.
- ♦ The Low Flow Rate and Low-Low Flow Rate alarms have been set to 125 and 113 BPH, respectively.

- The High Flow Rate and High-High Flow Rate alarms have been set to 200 and 210 BPH, respectively.
- Valve ESD-5980 on the discharge line of the Product Storage and Delivery Pump (ESE-403, ESE-405) is operational.

c) When the pipeline system is ready for startup, the SCADA Control operator shall contact SCADA Monitoring operators and the pipeline technicians.

d) IF maintenance was performed on the PLC, RTU, antenna, or other parts of the controls or communications systems for an MOV, THEN SCADA Control shall verify with the pipeline technician that the Functional Testing procedure has been performed on the MOV station and all equipment is operational. Refer to **Appendix 7.1, Functional Testing Procedure**.

e) IF maintenance was performed on the HV-8 station, THEN the pipeline technician shall physically verify that the station is mechanically complete, the bypass valves are closed and chain locked in the closed position, the inlet block valve is open and chain locked in the open position, and HV-8 is open and chain locked in the open position.

f) IF maintenance was performed on the HPSD-15 station, THEN the pipeline technician shall physically verify that the valve setting is mechanically complete, the upstream block valve (HV-14) and downstream block valve (HV-16) are chain locked open, and HPSD-15 is in the open position.

g) IF mechanical maintenance was performed on an MOV, THEN the MOV station may be locked out. IF the MOV station is locked out, THEN SCADA Control shall direct the pipeline technician to set up the valve station for normal operations before beginning Normal Startup.

- Unlock and open the SCADAPack PLC/RTU cabinet.
- Using the PLC keypad and the PLC screen (HMI) set AUTO/MANUAL to AUTO.
  Note: The pipeline technician must key in a password before he can switch to the AUTO mode.
- Unlock the LOCAL/REMOTE switch at the MOV and turn it to REMOTE.
- Request that the Kenova SCADA operator stroke the MOV to OPEN.
  Note: The Kenova SCADA operator must key in a password before he can switch to the MANUAL mode and stroke the valve from the SCADA screen.
- Verify that the MOV does open fully.
- Request that the Kenova SCADA operator stroke the MOV to CLOSE.
- Verify that the MOV does close fully.
- Open the manual block valves around the MOV and chain lock them in the open position.
- Request the Kenova SCADA operator to stroke the MOV to OPEN.
- Close the bypass valves and chain lock them in the closed position.
- Close and lock the SCADAPack PLC/RTU cabinet.
- Continue with a normal startup.

h) IF no maintenance was performed on an MOV station, THEN the SCADA Control operator shall restart the pipeline:

- Notify the SCADA Monitoring operators that the pipeline is about to be restarted.
- Set all MOVs to MANUAL on the SCADA Control system.
  Note 1: Putting the SCADA system in the MANUAL mode will prevent the low-low pressure shutdown logic from shutting MOVs during the pressure surges associated with starting up the pipeline.

Note 2: The SCADA Control operator must key in a password to set the Host SCADA and MOV Site to MANUAL.

- Open all MOVs, in sequence to load the pipeline.
- Verify that the SCADA system screen indicates OPEN for each MOV.
- Direct the Maytown plant operator to start the Product Storage and Delivery Pumps (ESE-403, ESE-405) and/or Kenova plant operator to start the Product Pumps (P-9, P-9A), based upon the section of pipeline that was taken out of service.
- Confirm with the Siloam operator that the process and valves are set to receive product. Monitor the pressures and flow in the pipeline along with the SCADA Monitoring operators until the pipeline reaches about 300 psig at Siloam.
- Communicate with pipeline technicians and SCADA Monitoring operators the status of the MOVs (normal/abnormal) along the pipeline.

i) When the pipeline pressure surges have leveled out, switch the MOV/SCADA system control to AUTO.

7.4. SHUTDOWN PROCEDURES (normal operating conditions)

This section describes a planned, orderly shutdown from normal operating conditions that is initiated and carried out by operators. The normal shutdown includes shutting down sections of the pipeline or the whole pipeline.

a) When the pipeline system is ready for shutdown, the SCADA Control operator shall contact the SCADA Monitoring operators and pipeline technicians and/or
   - Direct the Maytown plant operator to stop the Product Storage and Delivery Pumps (ESE-403, ESE-405)
   - Direct the Kenova plant operator to stop the Product Pumps (P-9, P-9A).

b) The SCADA Control operator shall put all pertinent MOVs in MANUAL mode and close all MOVs sequentially from the SCADA Control system. (**Note**: As the pumps are shut off and the MOVs are closed, low pressure may develop in certain areas of the pipeline as liquids settle out. The low-low pressure may cause some MOVs to close automatically. Other MOVs will have to be closed manually from the SCADA.)

c) The SCADA Control operator shall acknowledge all warning and alarm signals generated by the SCADA system.

d) The SCADA Control operator shall verify that each MOV station signals CLOSE on the SCADA screen.

7.5. ABANDONMENT OR DEACTIVATION OF FACILITIES

Each pipeline abandoned in place must be disconnected from all sources and supplies of hazardous liquid, purged of liquid, filled with water or inert material and sealed at the ends.

Permanent records shall be maintained in the files showing the date of abandonment and the media remaining in the pipeline. (See Form 102, Abandonment or Deactivation of Facilities.)

For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under, or through a commercially navigable waterway, the last Operator of that facility must file a report upon abandonment of that facility to the Department of Transportation. See 195.59 for more details about the filing requirements for Abandoned Underwater Facilities.

Deactivated pipelines that have not been fully abandoned will continue to be maintained in accordance to regulatory requirements.

7.6. PREVENTION OF ACCIDENTAL IGNITION

When a hazardous amount of vapor is being vented into open air, each potential source of ignition must be removed from the area and fire extinguishers provided.

a) Smoking is strictly prohibited during this operation.
b) Cutting and welding operations shall be stopped in the area near venting operation.
c) All equipment engines shall be turned off.
d) When the pipeline parallels overhead electric transmission lines or is in the same right-of-way, the blowdown connection shall direct vapor away from the electric conductors.

Cathodic protection rectifiers shall be shut off and/or a metallic bond installed across the section of pipe to be removed before separation is made.

Hazardous gas detection equipment shall be used to assure the absence of a combustible mixture in bell holes prior to performing any cutting or welding operation.

Suitable signs shall be posted to serve as warnings in the areas around structures or areas containing highly volatile liquid facilities where the possible leakage or presence of highly volatile liquid vapors constitutes a hazard of fire or explosion.

7.7. PUBLIC EDUCATION [49 CFR 195.440 & 442]

Company shall establish a continuing educational program to enable the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a hazardous liquid pipeline emergency and report it to the Operator, MarkWest, or the Fire Department, Police Department, or other appropriate public officials. The program must be in English and in other languages commonly understood by a significant number and concentration of non-English speaking population in the area. The Operator shall also maintain records of actual notification made as result of the program.

The Continuing Education Program must include:

a) Communications to the affected public, including printed materials, pipeline markers and public meetings.
b) Provisions to respond to requests for locating and marking pipelines to the persons requesting planned excavation activities.
c) Provisions for temporary marking of buried pipelines with wood lathes and red flagging.
d) Inspection during and after the excavation activities to verify the integrity of the pipeline.

The purpose of the Public Education Program is:

a) To establish and maintain liaison with the Fire Department, Police Department, and other appropriate public officials
b) To acquaint the officials with MarkWest's ability for emergency response
c) To educate the public and excavators how to locate the pipeline right of way (ONE CALL system) and how to identify and respond to potential emergencies.

Refer to the MarkWest Public Awareness Program for the plan elements.

7.8. INTERNAL AUDIT

Once per year and at intervals not to exceed fifteen months, MarkWest shall have an internal audit to assure that this manual is being followed, all records are being properly kept, all reports are being properly made and proper corrective action is being taken where deficiencies are found. (Refer to Form 100, Governmental, Maintenance and Inspection Reporting Schedules and Internal Audit Report, and OM&E Section 8.6, Inspection and Maintenance Checklist.)

7.9. TRAINING [49 CFR 195.403]

A continuing training program shall be established to instruct operating and maintenance personnel to carry out the operating and maintenance, and emergency procedures established under 195.402 that relate to their assignments. Form 117, Training Course Record, shall be completed following each training activity. Training is to be structured as to provide personnel with the following:

a) Familiarity with the operation of main block valves and their location on the pipeline, their function on the system, general procedures used during normal movement of liquids, as well as any emergency procedures.

b) Knowledge of a proper procedure to use to control any accidental release of the liquid and to minimize the potential for fire, explosion, toxicity or environmental damage.

c) Ability to recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions, failures and spills, and to safely take appropriate corrective action.

d) Awareness of the safety precautions to follow when attempting to repair facilities. (The pipeline section under repair shall be isolated and purged of the hazardous liquid before repairs are attempted.)

e) Understanding of the characteristics and hazards of the products being transported.

f) Knowledge of proper fire fighting equipment and the procedures to be used in emergencies.

g) Ability to recognize the hazardous liquids, know their characteristics, and know the possible hazards of vapor generation, of mixtures of vapor with air, the odorless characteristic of vapors, and the safety and environmental effects of water spray on hazardous liquid fires?.

h) Ability to take immediate action if an accidental release of hazardous liquid occurs in order to contain the spill and recover the product.

i) Knowledge, for critical personnel, regarding general corrosion reducing the pipe wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

j) Ability to recognize where unintended movement or abnormal loading of the pipeline by environmental causes, such as an earthquake, landslide, or flood would impair its serviceability.

k) Ability to recognize when any material defect or physical damage might impair the serviceability of the pipeline.

l) Knowledge of any malfunction or operating error that might cause the pressure of the pipeline to rise above 110 percent of its maximum operating pressure, and the characteristics of any leak that constitutes an emergency.

m) Knowledge of any safety-related condition that could lead to an imminent hazard and cause a 20 percent or more reduction in operating pressure or shutdown of operation of the pipeline.

Once per year and at intervals not to exceed fifteen months, MarkWest shall evaluate:

a) The program's effectiveness in achieving its objectives by reviewing personnel performance. Make any appropriate changes to the training program as necessary to ensure its effectiveness.

b) The supervisor's knowledge of the procedures that have been established in the operation and maintenance manual for which he is responsible.

c) To ensure procedure effectiveness, visual observation of personnel performing specific job tasks will be performed. Make any appropriate changes as necessary to the procedures to ensure adequacy.

d) An annual review of the Operations, Maintenance & Emergencies manual is performed with all MarkWest pipeline personnel and pipeline management to ensure procedures are adequate and effective.

7.10. COMMUNICATIONS [49 CFR 195.408]

The communication system used for pipeline operations is hand held, two-way radios and cellular telephones carried by all inspection and maintenance personnel working on the pipeline.

Telephone service provides communication with the Fire Department, Police Department, and other appropriate public officials during emergency conditions. Telephone communication is also received from the public during normal operation of and emergency conditions on the pipeline system.

The SCADA system utilizes satellite communications to monitor critical pressures and flows on the pipeline system. Delta V and Foxboro distributed control systems are used to monitor the pressure and flow from the pumps' discharge.

7.11. SCRAPER AND SPHERE FACILITIES [49 CFR 195.426]

For pipelines having scraper and sphere launching and receiving facilities, operators shall install and observe pressure readings on a pressure gauge, to ensure the pressure has been relieved safely through the relief device before opening the barrel to install or remove scrapers or spheres. On motor operated valves monitored through a SCADA system, the pressure within the scraper and sphere launching and receiving facilities may also be redundantly observed by a SCADA operator.

7.12. PIPE MOVEMENT [49 CFR 195.424]

The Operator, MarkWest, shall not perform work on the pipeline, such as moving of any pipe, until the pressure is reduced to 50 percent or less of the maximum operating pressure.

IF the pipeline contains highly volatile liquids AND the pipeline materials are joined by welding, THEN the pipeline shall not be moved unless:

a) Precautions are taken to protect the public against hazards while moving the pipeline including the use of warnings, and, where necessary, evacuating the area close to the pipeline;
b) It is impractical to drain the pipeline of highly volatile liquids;
c) The pressure in that line section is reduced to the lower of the lowest practical levels that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 psig above the vapor pressure of the commodity or 50 percent or less of the maximum operating pressure.

7.13. OVERPRESSURE PROTECTION [49 CFR 195.428]

a) Relief valves and pressure shutdown devices used as overpressure devices operated by MarkWest shall be inspected and tested twice per calendar year at intervals not to exceed 7-1/2 months. All relief valves are to have tags showing relief valve setting and date set. Any relief valve found leaking shall be overhauled. (Refer to Form 103, Relief Valve Inspection Report.)

b) Stop valves located between relief valves and the pressure to be protected shall be secured in the OPEN position at all times, except when closed during testing or overhaul.

c) Unless a field test to determine relief capacity is shown to be feasible and can be performed at one year intervals, a review of the required capacity of each relief valve must be made annually. The actual relieving capacity shall be such that the pipeline pressure shall not exceed 110 percent of the maximum operating pressure when the pipeline is connected to the pressure source where the maximum operating pressure could be exceeded as a result of a pressure control failure.

d) The pipeline main line valves shall be inspected twice each calendar year, at intervals not to exceed 7-1/2 months. Refer to Form 123, Valve Inspection Report.

e) Inspections and tests shall include each pressure limiting device, relief valve, pressure regulator, or other item of pressure control to determine that it is functioning properly, is in good mechanical condition and is adequate from the standpoint of capacity and reliability.

7.14. BREAKOUT TANK [49 CFR 195.432]

MarkWest does not have breakout tanks on its system.

7.15. SECURITY OF FACILITIES [49 CFR 195.436]

To prevent vandalism and unauthorized entry MarkWest will provide chain link fencing, which will be chained and locked, on all main pipeline valve sites. MarkWest personnel will prohibit unauthorized entry to the property to prevent vandalism of pipeline facilities.

7.16. SMOKING OR OPEN FLAMES [49 CFR 195.438]

MarkWest shall prohibit smoking and open flames where there is a possibility of the leakage of a flammable hazardous liquid or the presence of flammable vapors. Areas where smoking and open flames are prohibited include storage tanks, pumps, valves, leak repairs, barge, truck and railcar loading/unloading facilities, and the like. The work area must be thoroughly inspected for flammable liquids and combustible vapors before use of cutting torches or welding can begin.

NO SMOKING and NO OPEN FLAMES signs shall be posted and located in areas so designated.

7.17. ABNORMAL OPERATION

The following deviations from normal operation where the design limits of the system have been exceeded, shall be recognized as a possible emergency and shall be reason for prompt response, investigation and corrective action being taken:

a) Unintended valve closure or shutdown.
b) Increase or decrease in pressure or flow rate, over/under condition outside of normal operating limits.
c) Loss of communications (MOV, SCADA and telephone).
d) Operation of any safety device.
e) Reported leaks, ruptures or fires
f) Power Outage at a plant site or a MOV site
g) Any other malfunction of a component, deviation from normal operation or personnel error which could cause a hazard to persons or property.

Refer to **Appendix 7.2, Abnormal Operations Conditions (AOC) and Emergency Response Matrix**.

A timely review with operator personnel will be performed in the event of abnormal operations. Form 125, Abnormal Condition Review will be used to document this review.

After restoring the system to normal operations, the pipeline technician shall check at sufficient critical locations on the system to determine if the problem has been corrected and ensure continued integrity and safe operations.

Each MOV station shall undergo maintenance twice-per-year. The station will be checked for condition, operability, lubrication, electrical connections, RTU condition, and calibration of transmitters and proximity switches using Form 123, Valve Inspection Report, and any needed repairs will be made.

Listed on the following page are other possible abnormal situations to enable operators to recognize them and suggested actions to deal with such emergencies.

7.17.1. Floods and Hurricanes

When MarkWest determines that it is probable that a serious flood or hurricane of **Category 3** or greater will strike an area involving the pipeline, the Area Plant Manager or his/her designee will instruct the employees to secure all equipment possible. The Area Plant Manager or his/her designee will determine if evacuation is necessary.

7.17.2. Natural Disasters

Following natural disasters that required shutting down the pipeline, the pipeline technician shall inspect the pipeline and its facilities before the pipeline is returned to service.

7.17.3. Civil Disturbances

a) Notify the Area Plant Manager or his/her designee.
b) IN THE FOLLOWING ORDER, protect personnel, equipment, and property.

7.17.4. Bomb Threats

a) TAKE ALL BOMB THREATS SERIOUSLY.
b) Try and stay calm, do not panic.
c) Signal another employee, who can inform the Area Plant Manager or his/her designee of the call.
d) Attempt to keep the caller talking and obtain the following information:
   - Location of the bomb.
   - Time of detonation.
   - Appearance, size, and kind of bomb.
   - Purpose.
   - Make notes about the caller's voice.
e) Notify the Police and/or Fire Department.
f) Evacuate the area of the bomb threat.

7.18. DAMAGE PREVENTION PROGRAM [49 CFR 195.442]

This section establishes a written program to prevent damage to Company pipelines by excavation activities. For the purpose of this section, "excavation activities" include excavating, blasting, boring, tunneling, backfilling, removing above ground structures by either explosive or mechanical means, and other earth moving operations.

Participation in an "Underground Protection" program (ONE CALL system) provides the Company a means to implement the following requirements of 195.442(b). The program provides the following:

a) Identifying, on a current basis, those persons normally involved in excavation activities in the area.

b) Providing general notification to the public in the vicinity of the pipeline and actual notification of the persons normally engaged in excavation activities in the vicinity of the pipeline as often as needed to make them aware of the following:
   - The program's existence and purpose; and
   - How to learn the location of underground pipelines before excavation activities are begun.
c) A means of receiving and recording notification of planned excavation activities.
d) Actually notifying the persons who give notice of their intent to excavate, the types of temporary markings to be provided, and how to identify the markings.

7.18.1. Response to the Notification of an Excavation Activity

MarkWest's response to the notification of an "excavation activity" shall include the following:

a) Fill in the first section of Form 116, Request to Locate Pipeline or Notification of Planned Excavation Activities, identifying such items as location, date, duration, nature of excavation, and contact information of those originating and responsible for the work.
b) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins. Once the pipeline has been located and marked, the pipeline technician will document the information on the second half of Form 116.
c) Provide inspection of a pipeline that an Operator has reason to believe could be damaged by excavation activities as frequently as necessary during and after the activities to verify the integrity of the pipeline. Document the date and time of the inspections and any observations on the second half of Form 116. In the case of blasting, any inspection must include leakage surveys.

7.18.2. Qualifications of Pipeline Personnel Program

Assisting in planning, locating, and observing pipeline excavations is a covered task requiring a qualified MarkWest operator. Refer to the Manual on Pipeline System Operator Qualification Program for details.

7.18.3. Blasting in Vicinity of Pipeline

a) The Maytown pipeline system traverses active mining areas where blasting is performed. The blasting company shall provide a blasting plan and use seismographs to verify that the Peak Particle Velocity (PPV) is not exceeded.
b) No blasting is allowed within the pipeline right of way. If a case of unauthorized blasting is discovered in the area of the pipeline, leakage surveys are to be performed using gas detection instruments to assure the integrity of the pipeline is intact. MarkWest shall use Form 110, Procedures for Records Review and Field Inspection of Leakage Survey.
c) If blasting is to be performed within 500 feet of the pipeline, a seismic monitoring program shall be instituted by the contractor. A seismic monitoring unit in good working condition shall be utilized to measure the vibration at the pipeline. The Peak Particle Velocity (PPV) shall not exceed two (2) inches per second (IPS) for any blast. MarkWest shall be notified of any PPV reading approaching or exceeding 2 IPS.

SECTION 6 – DESIGN AND CONSTRUCTION

6.1. REQUIREMENTS [49 CFR 195.128 & 130]

New installations shall meet the minimum requirements as specified in the Federal regulations Title 49 CFR Part 195 for the design, fabrication, installation, inspection and testing provisions of liquid pipelines and pipeline facilities.

6.2. RESPONSIBILITY

If a contractor works on the system, it is the responsibility of MarkWest to ensure that the contractor follows the above requirements.

The Area Plant Manager or his/her designee shall be responsible for the design of all facilities.

6.3. MATERIAL SELECTION [49 CFR 195.4, 8, & 100]

Materials used for pipe and pipeline components shall be qualified by Subpart C of 49 CFR 195 and maintain the structural integrity of the pipeline under its maximum operating condition and other environmental conditions to which they will be subjected. Material shall also be chemically compatible with the product with which they come in contact.

6.3.1. Design Temperature [49 CFR 195.102]

a) Material for components of the system shall be chosen for the temperature environment in which the components will be used so that the pipeline will maintain its structural integrity.

b) Components of carbon dioxide pipelines that are subject to low temperatures during the normal operation because of rapid pressure reduction or during the initial fill of the line shall be made of materials that are suitable for those low temperatures.

6.3.2. New Pipe [49 CFR 195.112]

a) The pipe shall be made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.

b) The pipe shall be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe steel and mechanical tests for the pipe to provide pipe suitable for the use intended.

c) Each length of pipeline with an outside diameter of 4 ½ inches or more shall be marked on the pipe or pipe coating with the specifications to which it was made, the specified minimum yield strength or grade, and the pipe size. The marking shall be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed.

6.3.3. Used Pipe [49 CFR 195.114]

Used pipe installed shall meet specifications outlined in OM&E Section 6.3.2(a) and (b). In addition, pipe shall be of known specification and the seam joint factor shall be determined in accordance with 195.106(e). If the specified minimum yield strength or the wall thickness is not known, it is determined in accordance with 195.106(b) or (c) as appropriate. There may not be any of the following:

a) Buckles.

b) Cracks, grooves, gouges, dents or other surface defects that exceed the maximum depth of such a defect permitted by the specification to which the pipe was manufactured.

c) Corroded areas where the remaining wall thickness is less than the minimum thickness required by the tolerances in the specification to which the pipe was manufactured.

NOTE: Pipe that does not meet the requirements of paragraph (c) of this section may be used if the operating pressure is reduced to be commensurate with the remaining wall thickness.

6.3.4. Valves [49 CFR 195.116]

Each valve installed in a pipeline system shall comply with the following:

a) Each valve installed in a pipeline system shall be of a sound engineering design.

b) Materials subject to the internal pressure of the pipeline system, including welded and flanged ends shall be compatible with the pipe or fittings to which the valve is attached.

c) Each part of the valve that will be in contact with the hazardous liquid stream shall be made of materials that are compatible with each hazardous liquid anticipated to flow through the pipeline system.

d) Each valve shall be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in Section 5 of API Standard 6D.

e) Each valve other than a check valve shall be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

f) Each valve shall be marked on the body or the nameplate, with at least the following:

- Manufacturer's name or trademark.
- Class designation or the maximum working pressure to which the valve may be subjected.
- Body material designation (the end connection material, if more than one type is used).
- Nominal valve size.

6.3.5. Fittings [49 CFR 195.118]

a) Butt-welding type fittings shall meet the marking, end preparation, and the bursting strength requirements of ANSI B16.9 or MSS Standard Practice SP-75.

b) There shall not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting.

c) The fitting shall be suitable for the intended service and at least as strong as the pipe and other fittings in the pipeline system to which it is attached.

6.3.6. Provisions for Internal Passage [49 CFR 195.120]

Each component of a main line system, other than manifolds shall have a radius of turn that readily allows the passage of pipeline scrapers, spheres, and internal inspection equipment.

6.3.7. Fabricated Branch Connections [49 CFR 195.122]

Each pipeline system shall be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system.

6.3.8. Closures [49 CFR 195.124]

Each closure to be installed in a pipeline system shall comply with the ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, and shall have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

6.3.9. Flange Connection [49 CFR 195.126]

Each component of a flange connection shall be compatible with each other component and the connection as a unit shall be suitable for the service in which it is to be used.

6.3.10. External Pressure [49 CFR 195.108]

Any external pressure that will be exerted on the pipe shall be provided for in designing a pipeline system.

6.3.11. External Loads [49 CFR 195.110]

a) Anticipated external loads, e.g., earthquakes, vibrations, thermal expansion, and contraction shall be provided for in designing a pipeline system. In providing for expansion and flexibility, Section 419 of ASME/ANSI B31.4 shall be followed.

b) The pipe and other components shall be supported in such a way that the support does not cause excess localized stresses. In designing attachments to pipe, the added stress to the wall of the pipe shall be computed and compensated for.

6.4. CONSTRUCTION REQUIREMENTS

This section covers construction of new, replaced or relocated pipeline systems with steel pipe. Such pipeline systems shall be constructed in accordance with written specifications outlined in this section and Subpart D of 49 CFR 195. A daily progress report shall be maintained on Form 107, Construction Daily Progress Report, and submitted to the Manager of Operations or his/her designee.

6.4.1. Inspection – General [49 CFR 195.204]

Inspection shall be provided to ensure the installation of pipe or pipeline systems in accordance with the requirements of this subpart. No person shall be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected.

6.4.2. Material Inspection [49 CFR 195.206]

No pipe or other component shall be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability.

6.4.3. Welding of Supports and Braces [49 CFR 195.208]

Supports or braces shall not be welded directly to pipe that will be operated at a pressure of more than 100 psig.

6.4.4. Pipeline Location [49 CFR 195.210]

a) Pipeline right-of-way shall be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly.

b) No pipeline shall be located within 50 feet of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches of cover in addition to the procedure outlined under Item 6.4.11, "Cover Over Buried Pipeline".

6.4.5. Bending of Pipe [49 CFR 195.212]

a) Pipe shall not have a wrinkle bend.

b) Each field bend shall comply with the following:

- A field bend shall not impair the serviceability of the pipe.
- Each bend shall have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
- On pipe containing a longitudinal weld, the longitudinal weld shall be as near as practicable to the neutral axis of the bend, unless:
  - The bend is made with an internal bending mandrel.
  - The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

c) Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe shall be nondestructively tested either before or after the bending process.

6.4.6. External Corrosion Protection [49 CFR 195.557]

Each component in the pipeline system shall be provided with protection against external corrosion. For additional procedures refer to OM&E Section 9, "Corrosion Control".

6.4.7. External Coating [49 CFR 195.559]

No pipeline system component shall be buried or submerged unless that component has an external protective coating that:

a) Is designed to mitigate corrosion of the buried or submerged component.

b) Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture.

c) Is sufficiently ductile to resist cracking.

d) Has enough strength to resist damage due to handling and soil stress.

e) Supports any supplemental cathodic protection.

In addition, if an insulating-type coating is used, it shall have low moisture absorption and provide high electrical resistance.

Please refer to **Appendix 9.1** *Pipeline Coating Chart* for approved coatings, applications and restrictions.

6.4.8. Cathodic Protection System [49 CFR 195.563]

a) A cathodic protection system shall be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure shall be developed to determine whether adequate cathodic protection has been achieved.

b) A cathodic protection system shall be installed not later than one year after completing the construction. For additional procedures refer to OM&E Section 9, "Corrosion Control".

6.4.9. Excavation and Trenching (Section 31 of the MarkWest Corporate Safety Manual)

All excavation and trenching operations shall be conducted per Section 31 of the MarkWest "Corporate Safety Manual" as approved by management. Section 31 of the manual outlines procedures to be followed in accordance with regulations established by the Occupational Safety and Health Administration [29 CFR 1926.651-652] and the U.S. Department of Transportation [40 CFR 195.402(c)(14)].

Note: Adequate precautions are to be taken in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

6.4.10. Installation of Pipe in a Ditch [49 CFR 195.246]

All pipe installed in a ditch shall be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe.

6.4.11. Cover Over Buried Pipeline [49 CFR 195.248]

a) All pipe shall be buried so that it is buried below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or sea bottom, as applicable, complies with the following table.

Location	**Cover**	
	Normal (Inches)	Rock (Inches)
Industrial, commercial, and residential areas	36	30
Crossings of inland bodies of water with a width of at least 100 feet from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Deepwater port safety zone	48	24
Other offshore areas under water less than 12 feet deep as measured from the mean low tide	36	18
Any other areas	30	18

Note: Rock excavation is any excavation that requires blasting or removal by equivalent means.

b) Less cover than the minimum required by paragraph (a) of this section shall be used if:

- It is impracticable to comply with the minimum cover requirements.
- Additional protection is provided that is equivalent to the minimum required cover.

6.4.12. Clearance Between Pipe and Underground Structures [49 CFR 195.250]

Any pipe installed underground shall have at least 12 inches of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches but not less than 2 inches. However, where 12 inches of clearance is impracticable, the clearance may be reduced if adequate provisions are made for corrosion control.

6.4.13. Backfilling [49 CFR 195.252]

Backfilling shall be performed in a manner that protects pipe and pipe coating from equipment, and provides firm support for under the pipe.

6.4.14. Above Ground Components [49 CFR 195.254]

a) Any component shall be installed above ground in the following situations, if the other applicable requirements of this part are complied with:

- Overhead crossings of highways, railroads, or a body of water.
- Spans over ditch and gullies.
- Scraper traps or block valves.
- Areas under the direct control of the operator.
- In any area inaccessible to the public.

b) Each component covered by this section shall be protected from the forces exerted by the anticipated loads.

6.4.15. Crossing of Railroads and Highways [49 CFR 195.256]

The pipe at each railroad or highway crossing shall be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads.

6.4.16. Valves: General [49 CFR 195.258]

a) Each valve shall be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.

b) Each submerged valve located offshore or in inland navigable waters shall be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

6.4.17. Valves: Location [49 CFR 195.260]

A valve shall be installed at each of the following locations:

a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

b) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.

c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

e) On each side of a water crossing that is more than 100 feet wide from high water mark to high water mark unless the Secretary finds in a particular case that valves are not justified.

f) On each side of a reservoir holding water for human consumption.

6.5. WELDING

6.5.1. General Requirements [49 CFR 195.214]

a) All welding on hazardous liquid handling facilities shall be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of API 1104 (current edition accepted by DOT). The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

b) Each welding procedure shall be recorded in detail, including the results of the qualifying test. This record shall be retained and followed whenever the procedure is used.

6.5.2. Qualification of Welding Procedures

Each welding procedure shall be qualified under either Section IX of the ASME Boiler and Pressure Vessel Code or Section 5 of API Standard 1104 (current edition accepted by DOT), whichever is appropriate to the welding being performed. Each welding procedure shall be recorded in detail. Each record shall be retained and followed when welding is performed. The qualification test shall be performed by a qualified welder under the supervision of the welding inspector and shall be approved by MarkWest. The quality of the welds used to qualify the procedure shall be determined by destructive testing. Each welding procedure shall be recorded on forms furnished in API Standard Specification 1104. Forms include Standard Welding Procedure Specification and Coupon Test Report used for welder qualification tests.

6.5.3. Qualification of Contract Welders [49 CFR 195.222]

a) Before being allowed to weld on any hazardous liquid facility, contract welders shall be required to successfully pass qualification tests in the applicable O.D. size groups and wall thickness groups as required in API 1104 Section 6 and in the maximum yield of pipe on which they are expected to weld during the contract work.

b) If a contract welder has been previously qualified in the proper size group, wall thickness group, yield of pipe and has welded in such categories on company work with one weld successfully tested during the preceding 6 months, no requalification is necessary; however, each contract welder shall be requalified in each category each calendar year, with a maximum of 12 months between qualifications.

c) In the event a welder cannot pass the test requirements for branch connections, but can successfully pass all of the other requirements set out above, he will be qualified to perform all welding operations except those requiring fillet welds on pressure containing elements.

d) Welder qualification tests shall be recorded on forms furnished in API Standard Specification 1104. See Figure #2, API 1104.

6.5.4. Visual Inspection [49 CFR 195.228]

All welds shall be visually inspected. The preparation of the pipe prior to welding and the actual welding process shall be visually monitored by a qualified welding inspector. The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (ibr, see Sec. 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

6.5.5. Welds: Nondestructive Testing [49 CFR 195.234]

a) Nondestructive testing shall be performed by persons qualified per Section 8 of API Standard 1104 (Inspection & Testing of Production Welds). Testing shall be performed in accordance with procedures as outlined in Section 11 of API Standard 1104 (Procedures for Nondestructive Testing). The acceptability of a weld shall be determined according to Section 9 of API Standard 1104 (Acceptance Standards for Nondestructive Testing).

b) During construction, at least 10 percent of the girth welds made by each welder during each welding day shall be nondestructively tested over the entire circumference of the weld.

c) One hundred percent (100%) of each day's girth welds installed in the following locations shall be nondestructively tested unless impracticable, in which case at least 90 percent shall be tested. Nondestructive testing shall be impracticable for each girth weld not tested:

- At any onshore location where a loss of hazardous liquid could reasonable be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area.
- Within railroad or public road rights-of-way.
- At overhead road crossings and within tunnels.
- Within the limits of any incorporated subdivision of a state government.
- Within populated areas, including, but not limited to, residential subdivision, shopping centers, schools, designated commercial areas, industrial facilities, and places of public assembly.

d) When installing used pipe, 100 percent of the old girth welds shall be nondestructively tested.

e) At pipeline tie-ins, 100 percent of the girth welds shall be nondestructively tested.

f) All welds which are not hydrostatically tested in replacement sections shall be radiographed. The radiographic film of all welds made as part of pressure containing elements shall be properly identified and retained until the system has been successfully tested and/or place in service or, in special cases, may be retained as long as needed. A summary of all welds made as part of pressure containing elements on a project shall be documented and retained for the life of the facility by MarkWest, to be made a part of the permanent records.

6.5.6. Welding Miter Joints [49 CFR 195.216]

A miter joint is not permitted (not including reflections up to 3 degrees that are caused by misalignment).

6.5.7. Welding of Supports and Braces [49 CFR 195.208]

Supports and braces shall not be welded directly to pipe that will be operated at a pressure of more than 100 psig.

6.5.8. Welding: Weather [49 CFR 195.224]

Welding shall be protected from weather conditions that would impair the quality of the completed weld.

6.5.9. Welds: Repair or Removal of Defects [49 CFR 195.230]

a) Each weld that is unacceptable under Section 9 of API Standard 1104 shall be removed or repaired. A weld shall be removed if it has a crack that is more than 8 percent of the weld length.

b) Each weld that is repaired shall have the defect removed down to sound metal and the segment to be repaired shall 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 shall be inspected to ensure its acceptability.

c) Repair of a crack, or of any defect in a previously repaired area, shall be in accordance with the Company's weld repair procedures which conform to API 1104. Repair procedures shall 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.

6.6. HYDROSTATIC TEST REQUIREMENTS [49 CFR 195.300, 302, 304, 306, 308, & 310]

MarkWest shall be responsible for specifying the procedure and test pressure for all new/replaced line pipe in the System. A representative of MarkWest shall be directly responsible for conducting the field tests to the specification and for achieving maximum safety while testing the pipeline.

The test pressure for each pressure test conducted under Subpart E of 49 CFR 195 shall be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during the test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

MarkWest shall use water as the test medium.

Pipe associated with tie-ins shall be pressure tested, either with the section to be tied in or separately.

A record shall be made of each hydrostatic test required and the record retained as long as the facility tested is in use. The following information shall be included on Form 118, Field Pressure & Test Report, and forwarded to the Manager of Operations or his/her designee.

a) The pressure recording charts.

b) Test instrument calibration data.

c) The name of the operator, the name of the person responsible for making the tests and the name of the test company used.

d) The date and time of the test.

e) The minimum test pressure.

f) The test medium.

g) Description of the facility tested and the test apparatus.

h) Explanation of any pressure discontinuities, including test failures that appear on the pressure recording charts.

i) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows elevation and test sites over the entire length of the test section.

j) Temperature of the test medium or pipe during the testing period.

6.7. MAXIMUM OPERATING PRESSURE [49 CFR 195.106 & 406]

a) Except for surge pressures and other variations from normal operations, no operator shall operate the pipeline at a pressure that exceeds any of the following:

- The internal design pressure determined in accordance with 195.106(a).
- The design pressure of any other component of the pipeline.
- Eighty percent of the test pressure for any part of the pipeline which has been hydrostatically tested under Subpart E of 49 CFR 195.
- Eighty percent of the factory test pressure of the prototype test pressure for any individually installed component which is accepted from testing under 195.304.
- For pipelines under 195.302(b)(1) and (b)(2)(I) that have not been pressure tested under Subpart E of Part 195, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

b) The MOP of the Kenova to Siloam line has been established at 1150 psig in accordance with OM&E Section 6.7(a). The line was tested in 2005 to a minimum pressure of 1438 psig at the high point.

- The Maytown Pipeline (Maytown to Ranger) MOP is 2340 psig. The Transandy Pipeline (Ranger to Kenova) MOP is 2820. Both sections of pipelines are protected by two Pressure Safety Valves (PSV) located at the Maytown Facility. Both PSVs are set at 2340 psig.

- Over-pressure protection for the Siloam Pipeline (600# spec) where it ties into the Maytown/Transandy system (1500# spec) is being accomplished by HPSD-15. HPSD-15 is set to close on rising pressure if the Maytown/Transandy Pipeline pressure exceeds 1000 psig. This protection was designed in accordance with 195.104.

c) MarkWest training ensures that operators will prevent the pressure in a pipeline, during surges or other variations of conditions from normal operations, to exceed 110 percent of the operating pressure limit established under this section. MarkWest shall provide adequate controls and protective equipment to control the pressure within this limit.

d) DOT Part 195.2 defines a low stress pipeline to be a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength (SMYS) of the line pipe. Pipelines operated below 20% SMYS will be considered low-stress pipelines.

6.8. CONSTRUCTION RECORDS [49 CFR 195.266]

a) A complete record that shows the following shall be maintained by the Company for the life of the pipeline facility:

- The total number of girth welds and the number of nondestructively tested welds, including the number rejected and the disposition of each rejected weld.
- The size, grade and wall thickness of pipe installed, the amount, location and cover of each size installed.
- The location of each buried utility crossing.
- The location of each overhead crossing.
- The location of each valve.
- The location of each corrosion test station and cathodic protection system used.
- Hydrostatic test records.
- Location of pump station.
- Launcher and receiver facility.
- Safety Devices.
- All road crossings, railroad crossings and river crossings.
- Public Education Program.

6.9. MAPS AND RECORDS [49 CFR 195.404]

a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

- Location and identification of the following pipeline facilities:
  - Breakout tanks (if any).
  - Pump stations.
  - Scraper and sphere facilities.
  - Pipeline valves.
  - Facilities to which Sec. 195.402(c)(9) applies.
  - Rights-of-way.
  - Safety devices to which Sec. 195.428 applies
- All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.
- The maximum operating pressure of each pipeline.
- The diameter, grade, type, and nominal wall thickness of all pipe.

b) Each operator shall maintain for at least 3 years daily operating records that indicate:

- The discharge pressure at each pump station.
- Any emergency or abnormal operation to which the procedures under Sec. 195.402 apply.

c) Each operator shall maintain the following records for the periods specified:

- The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.
- The date, location, and description of each repair made to parts of the pipeline system other than pipe shall be maintained for at least 1 year.
- A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

6.10. INSPECTION / TEST RECORDS

The following records shall be kept of each inspection and each test performed for the time period indicated.

Inspection/Test	Minimum Frequency	Reference
Right-of-Way Surface Conditions	26 times/calendar year	195.402
Navigable Waterways	Once each five (5) years	195.412
Cathodic Protection Underground Facilities	Once (1) per calendar year	195.573
Corrosion of Buried Pipe External/Internal	As exposed or removed	195.569
Main Line Valves Check proper operation.	Twice (2) per calendar year	195.420
Pressure Devices: -Pressure limiting devices -Relief valves -Pressure regulators -Pressure control equipment Check proper operation, capability & reliability.	Once (1) per calendar year OR in case of highly volatile liquids twice (2) per calendar year.	195.428
Cathodic Protection Rectifiers	Six (6) times/calendar year	195.573
Examine Corrosion Monitoring equipment.	Twice (2) per calendar year	195.579
Firefighting Equipment	Monthly	OM&E Section 5.2 195.430
Review with personnel performance in meeting training program objective	Once (1) per calendar year	195.403
Review and/or revise training program	Once (1) per calendar year	195.403

6.11. CPM LEAK DETECTION [49 CFR 195.134 & 444]

This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system shall comply with Section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system.

The following is an excerpt from API 1130 Section 4.2 *Selection Criteria*

The CPM features listed below are not in any particular order nor is there any attempt to weight the importance of each. It must be noted that no one methodology or particular application possesses all of these features and certain features will be more appropriate for specific pipeline systems. A CPM system must have at least one of these features.

The CPM system may:

a. Possess accurate commodity release alarming.
b. Possess high sensitivity to commodity release.
c. Allow for timely detection of commodity release.
d. Require minimal software configuration and tuning.
e. Perform its CPM functions with existing sensors and instruments (or does not have special or additional requirements for instrumentation).
f. Be minimally impacted by communication outages or by data failures.
g. Accommodate complex operating conditions.
h. Be available during transients.
i. Be configurable to complex pipeline networks

j. Perform an imbalance calculation on meters at one instant in time.
k. Possess dynamic alarm thresholds.
l. Possess dynamic liquid pack constant.
m. Accommodate commodity blending.
n. Account for heat transfer.
o. Provide the pipeline system's real-time pressure profile.
p. Accommodate intermittent or permanent slack line conditions (avoiding alarms and not totally disabling all segments of the pipeline during the event).
q. Accommodate all types of liquids.
r. Identify leak location with appropriate mile post locations or nearest station.
s. Have the ability to display pressure history versus time for each line pressure location along a pipeline.
t. Provide for automatic and manual data substitution during periods of data non-availability (eg., communication outage, measurement failure, maintenance, etc.).
u. Provide composite indication of data attributes associated with supporting field inputs and calculated data.
v. Minimize the number of alarms by requiring supporting, and preferably independent, commodity release confirmation.
w. Identify the leak rate.
x. Accommodate commodity measurement and inventory compensation for various correction factors (temperature, pressure, density, meter factor).
y. Provide batch tracking with interface location, be able to compute bulk modulus, and perform inventory compensation.
z. Perform calculations quickly using data immediately as it becomes available.
aa. Validate commodity release alarms using redundant analysis within the same method as well as redundant analysis between methods.
ab. Accommodate pump start-ups/shutdowns, valves opening/closing, and other normal operational functions without generating alarms.
ac. Account for effects of drag reducing additive.
ad. Offer efficient field and Control Center support.
ae. Contain a leak probability analyzer to weigh all of the components of a leak (linepack loss, pressure/flow deviation, meter shortage) to assist a pipeline controller in making a leak declaration.
af. Possess ability to allow alarms to be integrated into the pipeline controller's alarm processing.
ag. Possess audit trails of CPM actions taken by pipeline controllers and allow saving of historical data.
ah. Have the ability to return to normal detectability limits rapidly after data or computer service is restored or after an unscheduled interruption.
ai. Have the ability to provide carious types of warnings and alarms for example warnings or alarms on data failure or unusual operating conditions that indicate the cause is not a commodity release.
aj. Provide an alarm under all operating conditions and will not be disabled or turned off automatically regardless of circumstances.
ak. Have the ability to automatically self test without affecting performance while the test is underway.

6.12. PUMPING EQUIPMENT [49 CFR 195.262]

a) Adequate ventilation shall be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices shall be installed to warn of the presence of hazardous vapors in the pumping station building.

b) The following shall be provided in each pump station:

- Safety devices that prevent over-pressuring if pumping equipment, including the auxiliary pumping equipment within the pumping station.
- A device for the emergency shutdown of each pumping station.
- If power is necessary to actuate the safety devices, an auxiliary power supply.

c) Each safety device shall be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

d) Except for offshore pipelines, pumping equipment shall be installed on property that is under the control of the operator and at least 50 feet from the boundary of the pump station.

e) Adequate fire protection shall be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power shall be provided for those pumps that are separate from the power that operates the station.

SECTION 3 – DEFINITIONS

3.1. DEFINITIONS [49 CFR 195.2]

Abandoned: Permanently removed from service. This applies to pipeline that has been fully purged, isolated from any energy sources such as active lines, and filled with an inert material such as water or nitrogen.

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: An area where the public could be exposed to hazards caused by active corrosion. Boundaries of other "Active Corrosion Zones" will be determined by an Engineering Services Pipeline/Corrosion/Pipeline Safety Engineer. This method will not apply to pipelines under cathodic protection.

Administrator: The Administrator, Research and Special Programs Administration or his or her delegate.

Atmospheric Corrosion: 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: The following 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;

- Faded, peeling, chalking, disbonded paint and/or miscellaneous rust bleed onto a coated steel surface.
- Passive surface oxidation, or surface rust, that does not show signs of corrosion pitting or peeling scale, or pipe damage.

Barrel: A unit of measurement equal to 42 U.S. standard gallons.

Breakout Tank: A tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

Carbon Dioxide: A fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Close Interval Survey: An electrical survey technique used to determine cathodic protection levels or corrosion potential of a metallic structure. This survey is also known as the Over-the-Line Survey technique. This type of survey is performed by taking structure to soil or half cell to half cell (bottle to bottle) readings at short intervals. These intervals can be anywhere from 2.5 feet to 20 feet in length, depending on the need and accessibility. Remote (Side Drain) readings may be included. A Close Interval Survey may be used in conjunction with interrupting all known current sources to determine IR drop.

Component: Any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

Computation Pipeline Monitoring (CPM): A software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline-operating anomaly that may be indicative of a commodity release.

Corrosion: Metal loss on a surface of pipe resulting from oxidation, electrochemical action, bacterial action, abrasion, cavitation, erosion, or other processes.

Corrosive Product: "Corrosive material" as defined by Sec. 173.136 Class 8-Definitions of this chapter.

Counterpoise: A buried cable installed and maintained by the power company connecting a series of electric power line towers used for grounding the towers. The counterpoise may be located under the towers or to the side of the towers.

Deactivated: A pipeline or segment of pipeline that has not been fully abandoned. This can pertain to idle lines not currently in production that have been removed from service temporarily due to maintenance, relocation, and repair. If deactivated, the pipeline or segment of pipeline will continue to be maintained according to all regulatory requirements. This definition also applies to pipeline or segments of pipeline that are labeled as "out of service" or "inactive".

Electrical Survey: A series of closely spaced pipe to soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Exposed Underwater Pipeline: An underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

External Corrosion, Contiguous Pitting: Individual corrosion pits that join together on the pipe surface. Contiguous means that the boundary of adjacent pits overlap or touch to the extent that they cannot be clearly separated as individual pits.

External Corrosion, Erosion: An acceleration of a corrosion process caused by the removal of corrosion products from an external surface due to the abrasive action of suspended particles and/or high velocities and turbulence (e.g., continuous running water).

External Corrosion, General Corrosion: Surface corrosion and/or corrosion pits which are so located that they join together to form contiguous corrosion over an extended area or uniform wall loss/thinning over an extended area.

External Corrosion, Localized Pitting: Individual corrosion pits that do not necessarily join together on the pipe surface to form a contiguous area of corrosion.

Fault Current: A current that flows from power line conductors to ground or to another conductor due to an abnormal connection (including an Arc) between the two. A "Fault Current" flowing to ground (earth) may be called a "Ground Fault Current."

Flammable Product: "Flammable liquid" as defined by Sec. 173.120 Class 3-Definitions of this chapter.

Gathering Line: A pipeline 219.1 mm (8⅝ in) or less nominal outside diameter that transports petroleum from a production facility.

Gulf of Mexico and its inlets: The waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to Navigation: For the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Hazardous Liquid: Petroleum, petroleum products, or anhydrous ammonia.

Highly Volatile Liquid (HVL): A hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8° C (100° F).

In-Plant Piping System: Piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under Sec. 195.406(b).

Interstate Pipeline: A pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

Intrastate Pipeline: A pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.

IR Drop or Voltage Drop Error: The potential error in the "off" pipe to soil potential that is caused by current flow in the soil. Interrupting all known current sources minimizes IR Drop errors.

Jurisdictional Pipeline or Pipeline System: All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

Line Section: A continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

Low-Stress Pipeline: A hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Maximum Allowable Operating Pressure (MAOP): The maximum allowable operating pressure is the maximum pressure at which a line segment is qualified to operate.

Maximum Operating Pressure (MOP): The maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this part.

Nominal Wall Thickness: The wall thickness listed in the pipe specifications.

Offshore: Beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator: A person who owns or operates pipeline facilities.

Outer Continental Shelf: All submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person: Any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Petroleum: Crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Petroleum Product: Flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

Pipe or Line Pipe: A tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.

Pipeline or Pipeline System: All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

Pipeline Environment: The pipeline environment includes soil resistivity (high and low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline Facility: New and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.

Production Facility: Piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where CO2 is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

RSTRENG: A software program developed by the American Gas Association (AGA) to predict the remaining wall strength of corroded pipe.

Rural Area: Outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.

Selective Seam Corrosion (SSC): A form of internal or external corrosion typically associated with the longitudinal weld seam of older electric resistance welding (ERW) or flash-welded pipe. Such corrosion appears as an elongated, narrow, sharp-bottomed groove usually located at the weld centerline parallel to the pipe axis. SSC usually (but not always) occurs along with other forms of corrosion that involve the longitudinal weld seam. Short lengths of SSC can be detrimental to pipeline integrity and should be removed from the pipeline. Neither the ASME/ANSI B31G manual calculation method nor AGA/Battelle RSTRENG computer program should be used to determine the acceptability of SSC.

Specified Minimum Yield Strength (SMYS): The minimum yield strength, expressed in p.s.i. (kPa) gage, prescribed by the specification under which the material is purchased from the manufacturer.

Stress Level: The level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

Supervisory Control and Data Acquisition (SCADA): A monitoring and hardware control tool that is used to enhance the abilities of a pipeline controller to recognize and react to hydraulic anomalies that may be indicative of a pipeline leak or product release. A SCADA system is considered a CPM system.

Surge Pressure: Pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

Toxic Product: "Poisonous material" as defined by Sec. 173.132 Class 6, Division 6.1-Definitions of this chapter.

Unusually Sensitive Area (USA): A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under Sec. 195.6.

3.2. ACRONYMS

AC = Alternating Current

ALPS = Appalachian Liquids Pipeline System

AOC = Abnormal Operating Conditions

CPM = Computation Pipeline Monitoring

DC = Direct Current

EFRD = Emergency Flow Restricting Device

HVL = Highly Volatile Liquid

MMI = Man-Machine Interface

MOP = Maximum Operating Pressure

MOV = Motor Operated Valve

NGL = Natural Gas Liquids

NPMS = National Pipeline Mapping System

PSV = Pressure Safety Valve

RTU = Remote Transmission Unit

SCADA = Supervisory Control and Data Acquisition

USA = Unusually Sensitive Area

SECTION 11 – EMERGENCY CONTACT LISTS

11.1. INTRODUCTION

This list of names and telephone numbers is provided as a comprehensive list of emergency response contacts and is intended to make things a bit easier for anyone caught in a difficult time; a time of an emergency. In a time of emergency a person's emotions may give way to panic, pushing aside their normal wit or logic for handling a given situation. If kept close-at-hand, perhaps this list of people, organizations, and phone numbers can assist you in making things happen as best they will in the event you and your fellow workers are confronted with making emergency response decisions.

These emergency response contacts include names and phone numbers for obtaining help and information for everything from getting an injured person to the hospital to gasoline spill removal assistance to contacting help for an all-out fire/explosion emergency with fatalities and multiple injuries.

Each type of an emergency (serious injury, fire, large natural gasoline spill, natural disaster, crime, etc.) may require contacting only a certain few of the names provided by this list. In the case of government emergency response agencies their responsibilities often overlap and they can or will call other agencies once notified, thereby, possibly reducing the number of calls to be made by MarkWest personnel.

If you are the first to detect or respond to an emergency, contact your supervisor, as quickly as possible, for assistance with the emergency at hand and for providing help in making contacts with the proper emergency response agencies. Everyone that must be contacted in an emergency should be contacted; however, no more persons or groups than necessary should be involved.

If you find that any of the names or telephone numbers are incorrect, have changed, or that more names and numbers should be added please contact Jamie Adams, Keith Hayes, or Wes Carter.

Distribution of Copies:

Keith Hayes
Wes Carter
Jeff Stark
Rick Bryant
Carl Hunt
George Robinett
Jamie Adams
Siloam Plant
Kenova Plant
Maytown Plant
Boldman Plant

11.2. TABLE OF CONTENTS

PLANTS:

PIPELINES:

11.2.1. SILOAM PLANT

Medical Emergency Response:

Ambulance:	Life Ambulance, Portsmouth, Ohio	740-354-5433
	Portsmouth Ambulance	740-353-7553
Emergency Medical Service:		
	Our Lady of Bellefonte Hospital Outreach Center	606-932-3150
	South Shore, Kentucky	606-932-3159
Hospitals:	Southern Ohio Medical Center	740-354-5000
	Portsmouth, Ohio	740-356-5000
	Our Lady of Bellefonte Hospital	606-833-3333
	Bellefonte, Kentucky	
	University Hospital (Burn Center)	513-584-1000
	Cincinnati, Ohio	
	Shriner's Hospital	513-872-6000
	Cincinnati, Ohio	

Emergency Response Personnel:

Bob Waddell	Operations Manager	(Cell) (740) 464-0285 (Work) 606-932-3111 ext. 228 (Home) 740-259-2646 (Pager) 606-924-4717
Bob Craft	Compliance Technician	(Cell) (606) 923-8423 (Work) 606-932-3111 ext.225 (Home) 606-473-5096
Ron Smith	Area Plant Manager	(Cell) (740) 464-0284 (Work) 606-932-3111 ext. 223 (Home) 740-820-8793 (Pager) 606-932-7563

Fire Departments: **Emergency-911**

South Shore Volunteer Fire Department 606-932-3222
Portsmouth City Fire Department 740-353-2111
[NOTE: Local Fire Departments can be reached by the Greenup County Disaster Emergency Services (DES) Coordinator @ 606-473-5644 or 606-473-9833.]
Greenup County 911 Dispatcher 606-836-8189

Police & Sheriff's Departments: **Emergency-911**

Greenup County Sheriff's Department 606-473-9833
Police (South Shore, KY) 606-932-3311

11.2.2. KENOVA PLANT

SCADA Control:			(Main) 304-453-1793 (Cell) 606-831-0843 (Toll Free) 877-675-9378

Medical Emergency Response:

Ambulance:	Lifeline Medical Transport Huntington, WV		304-523-4525
	Portsmouth Ambulance Service South Point, OH		740-894-7612
Emergency Medical Service:	Tri State Medical Center Kenova, WV		304-453-6300
Hospitals:	Cabell Huntington Hospital		304-526-2000
		1340 Hal Greer Boulevard	
		Emergency/ Trauma	304-526-2200
	St. Mary's Hospital		304-526-1000
		2900 First Avenue	
		Emergency/ Trauma	304-526-1111

Emergency Response Personnel:

Keith Anderson	Senior Plant Technician	(Cell) 304-831-9159 (Work) 304-453-1793 (Home) 304-453-5404 (Pager) 304-526-6846
Ron Smith	Area Plant Manager	(Cell) 740 464-0284 (Work) 606-932-3111 ext. 225 (Home) 740-820-8793 (Pager) 606-932-7563
Bob Craft	Compliance Technician	(Cell) (606) 923-8423 (Work) 606-932-3111 ext.225 (Home) 606-473-5096

Fire Departments:	**Emergency-911**
Huntington Fire Department	304-526-8444
South Point Fire Department	800-282-7777
Chesapeake Fire Department	740-867-5988
Locally	Dial 911

Police & Sheriff's Departments:	**Emergency-911**
Wayne County Sheriff's Department (Dispatcher)	304-272-6378
State Patrol, Wayne, WV	304-272-5131

FIRE-AMBULANCE-SHERIFF	800-642-3582

11.2.3. MAYTOWN PLANT

Medical Emergency Response:

Ambulance:	Trans Star		
	Prestonsburg, KY		606-886-6664
	Martin, KY		606-285-9313
	Respond Ambulance Service		
	Prestonsburg, KY		606-874-8000
Hospitals:	Highlands Regional Medical Center		
	5000 Kewy Hwy. 321		606-886-8511
	Prestonsburg, KY	Toll Free From Pikeville	606-437-6921
	Our Lady of the Way Hospital		
	Martin, KY		606-285-5181

Emergency Response Personnel:

Keith Hayes	Area Plant Manager	(Work) 606-478-4991 (Home) 606-285-3247 (Cell) 606-226-3656
Bolten Martin	Senior Plant Technician	(Work) 606-478-4991 (Home) 606-358-4457 (Cell) 606-424-7829
Jim Bailey (Equitable)	Plant Manager	(Work) 606-285-3949 (Home) 606-285-9923 (Cell) 606-424-4731
Jamie Adams	Compliance Technician	(Work) 304-453-1793 x3218 (Home) 606-547-0096 (Cell) 304-634-5584

Fire Departments:	**Emergency-911**
Maytown Fire Department	606-285-9698
Martin Fire Department	606-285-3162
Garrett Fire Department	606-358-3473

Police & Sheriff's Departments:	**Emergency-911**
Floyd County Sheriff's Department	606-886-6171
State Police, Pikeville KY	606-433-7711

11.2.4. BOLDMAN PLANT

Medical Emergency Response:

Ambulance:	Respond Ambulance Service Allen, KY	606-874-8000
	DHP Ambulance Pikeville, KY	606-432-0151
Hospitals:	Pikeville Methodist Hospital Pikeville, KY	606-437-3500
	McDowell Appalachian Regional Hospital McDowell, KY	606-377-3400
	Highland Regional Medical Center Prestonsburg, KY Pikeville, KY	 606-886-8511 606-437-6921

Emergency Response Personnel:

Keith Hayes	Area Plant Manager	(Work) 606-478-4991 (Home) 606-285-3247 (Cell) 606-226-3656
Bolten Martin	Plant Technician	(Work) 606-478-4991 (Home) 606-358-4457 (Cell) 606-424-7829
Jamie Adams	Compliance Technician	(Work) 304-453-1793 x3218 (Home) 606-547-0096 (Cell) 304-634-5584

Fire Departments:	**Emergency-911**
Hurricane Creek Fire Department	606-478-2222
Coal Run Fire Department	606-432-5801
Tolers Creek Vol. Fire Department	606-478-4444
Betsy Layne Fire Department	606-478-4445
Pikeville Fire Department	606-433-9777

Police & Sheriff's Departments:	**Emergency-911**
Floyd County Sheriff's Department	606-886-6171
State Police, Pikeville KY	606-433-7711
Pike County Sheriff's Department	606-432-6260

11.2.5. SILOAM PIPELINE (Kenova to Siloam)

Medical Emergency Response:

Ambulance:	Eastern Greenup and Boyd Counties	606-836-7888
	Eastern Greenup County	606-836-9111
	Boyd County	606-325-9702
	If out of the "932" phone exchange and still in "606" area code	Dial 911
Hospitals:	Southern Ohio Medical, Portsmouth, OH	740-354-5000
	Our Lady of Bellefonte, Bellefonte, KY	606-833-3333
	Cabell Huntington, Huntington, WV	304-526-2200
	St. Mary's, Huntington, WV	304-526-1000

Emergency Response Personnel:

Wes Carter	Pipeline Manager	(Cell) (606) 923-2692 (Work) 304-453-1793 ext. 3207 (Home) 606-932-3220 (Pager) 606-924-4801
Jeff Stark	Pipeline Technician	(Work) 304-453-1793 x206 (Home) 606-286-5071 (Cell) 606-831-0948 (Pager) 304-540-1152
Rick Bryant	Pipeline Technician	(Work) 304-453-1793 x209 (Home) 606-928-9872 (Cell) 606-831-1088 (Pager) 606-924-8060
Carl Hunt	Pipeline Technician	(Work) 304-453-1793 x204 (Home) 606-326-0333 (Cell) 606-831-3111 (Pager) 304-526-7651
George Robinette	Pipeline Technician	(Work) 604-453-1793 (Cell) 606-831-2247 (Home) 304-648-5532 (Pager) 606-327-2943
Keith Hayes	Area Plant Manager	(Work) 606-478-4992 (Home) 606-285-3247 (Pager) 606-924-8043
Jamie Adams	Compliance Technician	(Work) 304-453-1793 x3218 (Home) 606-547-0096 (Cell) 304-634-5584

Fire Departments:	**Emergency-911**
Ashland City Fire Department	606-329-2191
Load Volunteer Fire Department	606-928-6421
Lloyd Volunteer Fire Department	606-473-5511
Greenup City Fire Department	606-836-8189
Russell City Fire Department	606-329-9911
Cannonsburg Volunteer Fire Department	606-329-0800
Catlettsburg City Fire Department	606-739-5126

Police & Sheriff's Department:	**Emergency-911**
South Shore Police	606-932-3311
Catlettsburg Police	606-739-5126
Sheriff - Greenup County	606-473-9833
Sheriff - Boyd County	911 locally
Other Departments	911 locally

Local police and sheriff departments can be reached by the County Disaster Emergency Services (DES) Coordinator:

Greenup County	606-473-5644 or 606-473-9833
Boyd County	606-329-9639 (911 Dispatcher)

11.2.6. TRANSANDY PIPELINE (Ranger to Kenova)

Medical Emergency Response:

Ambulance:	Wayne County	304-272-5101 800-642-3582 304-523-4525
	Lincoln County	304-824-7871
	Mingo County	304-235-3567 304-393-4060
Hospitals:	Cabell Huntington, Huntington, WV	304-526-2200
	St. Mary's, Huntington, WV	304-526-1000
	Appalachian Regional, S. Williamson, WV	606-237-1700
	Three Rivers, Louisa, KY	606-638-1222

Pipeline Emergency Response Personnel:

Wes Carter	Pipeline Manager	(Cell) (606) 923-2692 (Work) 304-453-1793 ext. 3207 (Home) 606-932-3220 (Pager) 606-924-4801
Jeff Stark	Pipeline Technician	(Work) 304-453-1793 x206 (Home) 606-286-5071 (Cell) 606-831-0948 (Pager) 304-540-1152
Rick Bryant	Pipeline Technician	(Work) 304-453-1793 x209 (Home) 606-928-9872 (Cell) 606-831-1088 (Pager) 606-924-8060
Carl Hunt	Pipeline Technician	(Work) 304-453-1793 x204 (Home) 606-326-0333 (Cell) 606-831-3111 (Pager) 304-526-7651
George Robinette	Pipeline Technician	(Work) 604-453-1793 (Cell) 606-831-2247 (Home) 304-648-5532 (Pager) 606-327-2943
Keith Hayes	Area Plant Manager	(Work) 606-478-4992 (Home) 606-285-3247 (Pager) 606-924-8043
Jamie Adams	Compliance Technician	(Work) 304-453-1793 x3218 (Home) 606-547-0096 (Cell) 304-634-5584

Fire Departments:		**Emergency-911**
Wayne County	Locally 911 or	304-272-6333
Lincoln County	Locally 911 or	304-824-3343
Mingo County		304-235-0566
Police & Sheriff's Departments:		**Emergency-911**
Wayne County		304-272-5131 304-272-5101 800-642-3582 304-272-6378
Lincoln County		304-824-7990 304-824-3101
Mingo County		304-235-0300

11.2.7. KENTUCKY HYDROCARBON PIPELINE (Maytown to Ranger)

Medical Emergency Response:

Ambulance:	Floyd County, KY	606-886-6664 606-874-8000
Martin County, KY		606-298-7077 606-298-3501
Wayne County, WV		304-272-5101 800-642-3582 304-523-4525
Mingo County, WV		304-235-3567 304-393-4060
Lincoln County, WV		304-824-7871
Hospitals:	Highlands Regional, Prestonsburg, KY	606-437-6921 606-886-8511
Paul B. Hall Regional, Paintsville, KY		606-789-3511
Three Rivers, Louisa, KY		606-638-1222 606-638-9451
Appalachian Regional, S. Williamson, WV		606-237-1700

Pipeline Emergency Response Personnel:

Wes Carter	Pipeline Manager	(Cell) (606) 923-2692 (Work) 304-453-1793 ext. 3207 (Home) 606-932-3220 (Pager) 606-924-4801
Jeff Stark	Pipeline Technician	(Work) 304-453-1793 x206 (Home) 606-286-5071 (Cell) 606-831-0948 (Pager) 304-540-1152
Rick Bryant	Pipeline Technician	(Work) 304-453-1793 x209 (Home) 606-928-9872 (Cell) 606-831-1088 (Pager) 606-924-8060
Carl Hunt	Pipeline Technician	(Work) 304-453-1793 x204 (Home) 606-326-0333 (Cell) 606-831-3111 (Pager) 304-526-7651
George Robinette	Pipeline Technician	(Work) 604-453-1793 (Cell) 606-831-2247 (Home) 304-648-5532 (Pager) 606-327-2943
Keith Hayes	Area Plant Manager	(Work) 606-478-4992 (Home) 606-285-3247 (Pager) 606-924-8043

Jamie Adams	Compliance Technician	(Work) 304-453-1793 x3218 (Home) 606-547-0096 (Cell) 304-634-5584	
Fire Departments:			**Emergency-911**
Floyd County, KY			606-886-1010 606-886-6711 606-285-3162
Martin County, KY			606-298-3211 606-395-5157
Wayne County, WV		Locally 911 or	304-272-6333
Mingo County, WV			304-235-0566
Lincoln County, WV		Locally 911 or	304-824-3343
Police & Sheriff's Departments:			**Emergency-911**
Floyd County, KY			606-886-6171 606-886-6711
Martin County, KY			606-298-2828
Wayne County, WV			304-272-5131 304-272-5101 800-642-3582 304-272-6378
Mingo County, WV			304-235-0300
Lincoln County, WV			304-824-7990 304-824-3101

11.2.8. EMERGENCY RESPONSE AGENCIES

KENTUCKY:

Kentucky DES Coordinator	606-886-9157 606-886-9302
US Coast Guard Group Ohio Valley Louisville, KY	800-253-7465
EPA - Rick Seelhurst	606-920-2067 Home: 606-932-4280
LEPC Local 24 hour warning	606-473-9833
Kentucky Regional Poison Control	800-722-5725

WEST VIRGINIA:

US Coast Guard, Huntington, WV	Day: 304-528-5524 Night: 304-528-3380
Cabell-Wayne Local Emergency Planning	304-526-9800

FEDERAL/OTHER:

National Response Center (Oil Spills)	800-424-8802
Chemtrec	800-424-9300
Association of American Railroads Ken Holgard, Louisville, KY Washington, DC	800-826-4662 202-639-2222 Fax: 202-639-2930
Environmental Protection Agency (EPA)	404-347-4062

11.2.9. FATALITIES OR MULTIPLE INJURIES

Fatalities or Multiple (five or more) Injuries

Federal OSHA, Regional Administrator Atlanta, GA	404-347-3573
Federal Department of Transportation Office of Pipeline Safety	800-424-8802
US Coast Guard Huntington, WV	304-529-5524 or 304-528-3380
Louisville, KY	800-253-7465
St. Louis, MO	800-325-7376

11.2.10. FIRE, EXPLOSIONS, OR TOXIC CHEMICALS & OIL SPILLS OR RELEASES

Kentucky:

Kentucky Disaster Emergency Services	
Frankfort, KY	606-886-9157
Prestonsburg, KY	606-886-9302
Kentucky Fire Marshall	502-564-3626
Natural Resource & Environmental Protection Cabinet Frankfort, KY	502-564-2380
Kentucky EPA - Air Quality, Frankfort, KY	502-564-2150
Kentucky EPA - Water Quality, Frankfort, KY	502-564-3410
Kentucky EPA - Waste Management, Frankfort, KY	502-564-6716
US Coast Guard, Louisville, KY	800-253-7465
EPA Region IV - Atlanta, Georgia	404-224-1996

West Virginia:

US Coast Guard, Huntington, WV	304-528-3380
EPA Region III - Philadelphia, PA	215-597-9880

Federal/Other:

National Response Center, Washington, DC	800-424-8802
Federal EPA - Air Quality Region IV, Atlanta, GA	404-347-5250
Federal Department of Transportation Office of Pipeline Safety	800-424-8802

11.2.11. QUALIFIED CONTRACTORS

C.J. Hughes Construction Huntington, West Virginia	Day:	800-882-3165
	Day:	304-522-3868
	Night:	740-533-0609
	Mobile:	304-544-1668
	Pager:	304-526-3481
	Night:	740-894-5903
Western Construction	Office:	606-874-1660
Eastern Pipeline Company	Office:	606-874-9254

11.2.12. EMERGENCY RESPONSE CONTRACTORS

Contract Fire Fighters

Boots & Coots Fire Fighters	
Houston, TX	713-621-7911
Red Adair Fire Fighters	
Houston, TX	713-462-6479

Hazardous Material Response Contractors

L&L Transportation	
Waterloo, IN	219-837-7826
Propane Transport (PTI)	
Milford, OH	513-575-2500

Oil Spill Response and Clean-up Contractors

ChemServ	
Cincinnati, OH	800-860-7378
Bell Par Waste Management	
Cincinnati, OH	513-353-4500
West Virginia	304-776-5972
Spade Corporation	
Kentucky	502-863-2121
Safety Supplies, Inc.	
Huntington, WV	800-523-4428
Orr Safety Equipment Company, Inc.	
Cincinnati, OH	800-722-5059
*Weavertown Environmental Group	
Office (24 hours)	740-865-2511
Emergency Response	412-746-4850
*Ferguson-Harbour	
Johnson City, TN	800-235-1344
Office (24 hours)	423-822-3295

*NOTE: IF NEITHER OF THE ABOVE CONTRACTORS ARE AVAILABLE (UNABLE TO CONTACT) THEN CONTACT THE FOLLOWING CONTRACTOR:

Inland Rivers Environmental	
Office (24 hours)	800-595-5332

Please note that MarkWest Hydrocarbon does not have a current contact with Inland Water Response Network (IWRN). Should it become necessary to utilize their services a contact would have to be agreed upon.

11.2.13. DENVER AND OTHER EMERGENCY CONTACT PERSONNEL

Denver Office	303-290-8700 800-467-3468 Fax: 303-290-8769
Steve Dickerson, Sr. Vice President NEBU	(Office) 713-965-0208 (Cell) 281-630-2804
Bruce Gillick, EH&S Manager	(Office) 303-290-8700 x128 (Cell) 720-308-7667
Christy Trontell, Environmental Coordinator	(Office) 303-925-9209 (Cell) 303-588-0281

MARKWEST ENERGY PARTNERS, L.P.

OPERATOR QUALIFICATION PROGRAM

DOT 49 CFR Part 195 (Liquid)

Effective Date: April 2001

Revision Date: June 2007

Author: B. Gillick

SCOPE

The Operator Qualification Plan encompasses MarkWest personnel and Contractors who perform Covered Tasks as identified by the Department of Transportation 49 CFR Part 195, Subpart G (Liquid). This will ensure that all personnel described herein are Qualified in accordance with the Operator Qualification Rule, and that adequate records to document these qualifications are maintained.

DEFINITIONS

The following definitions apply for the purposes of this program.

A. Abnormal Operating Condition – A condition identified by the Pipeline Operator that may indicate a malfunction of a component or deviation from normal operations indicative of a condition exceeding design limits or one that might otherwise result in a hazard to persons, property or the environment.

B. Accident (liquid lines) – As defined in 195.50

- (a) Explosion or fire not intentionally set by the operator.
- (b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:
  - (1) Not otherwise reportable under this section;
  - (2) Not one described in 195.52(a) (4);
  - (3) Confirmed to company property or pipeline right-of-way; and
  - (4) Cleaned up promptly;
- (c) Death of any person;
- (d) Personal injury necessitating hospitalization;
- (e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

C. Construction – An activity that occurs to pipeline facilities on new and/or replacement components not physically connected to existing pipeline facilities. Tasks that involve construction prior to actual tie-in are not Coverer Tasks.

D. Contractor – Any employer, or their sub-contractor, who performs Covered Tasks as identified under the definition of covered tasks and who is not an operator.

E. Pipeline Operator – Refers to the pipeline operator employing the Company.

F. Evaluation – The process used to evaluate an individual's ability to perform a Covered Task as provided herein.

G. Evaluator – Person who is authorized to assess and document the qualification of an individual and thereby determine if the individual is Qualified to perform a Covered Task.

H. Incident – (gas lines) – As defined in 49 CFR 191.3
An event that involves the unintentional release of gas and (at least one of the following):

- Death or personal injury requiring hospitalization.

- Estimated property damage (including gas loss) of at least $50,000.
- An event that results in the emergency shutdown of an LNG facility; or
- An event that the operator feels is significant enough to warrant telephonic reporting.

G. Integrity – The pipeline's ability to operate safely and to withstand the stresses imposed during operation.

H. Normal Operating Conditions - Conditions where the system as a whole and all of its components function in their designed manner and capacity

I. Operator Qualification Program Manager – Individual responsible for program implementation and maintenance.

J. Pipeline – All parts of those physical facilities through which NGL moves in transportation, including pipe, valves and other appurtenances attached to pipe; pumps; meter stations; regulator stations; delivery stations; and holders and fabricated assemblies.

K. Pipeline Facility – New and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of liquid hydrocarbons or in the treatment of NGL during the course of transportation.

L. Performed on a Pipeline Facility – An activity performed by an individual, which directly impacts a pipeline facility. This does not include pipe and appurtenances that have been removed from the pipeline for work elsewhere.

M. Qualified – An individual is "Qualified" in a Covered Task who has been evaluated and found capable of performing the task and of recognizing and reacting properly to reasonably anticipated abnormal operating conditions associated with that task.

COVERED TASK(S)

A Covered Task is a task that meets all four of the following requirements:

1. Is performed on a pipeline facility,
2. Is an operations or maintenance task,
3. Is performed as a requirement of this part [49 CFR Part 195]
4. Affects the operation or integrity of the pipeline.

EVALUATION

The evaluation of individual qualifications is an objective, consistent process that documents the ability to perform the Covered Task. This includes the Individual's ability to recognize and react to Abnormal Operating Conditions (AOC's) the Operator reasonably anticipates a Qualified Individual may encounter while performing the Covered Task.

Individuals will be evaluated by one or more of the following methods for transitional, initial and subsequent qualification.

- Written Exam
- Oral Exam
- Observation during:
  1. Performance on the job
  2. On the job training
  3. Simulations
- Computer based evaluations or simulations

- Vendor or Industry validations or certificates

Other evaluation methods must be approved by the Operator Qualification Performance Manager.

MarkWest will ensure through evaluation that individuals performing covered tasks are qualified. Individuals will be qualified through classroom and on-the-job training. On-going evaluation will be documented by written exam results, oral exams and job observations. **After December 16, 2004 observation of on-the-job performance may not be used as the sole method of evaluation. MarkWest does not use work performance history reviews as an evaluation method.**

EVALUATION PROCESS

MarkWest will provide training, as appropriate, to ensure that individuals, including contract personnel, performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities. Documentation of all evaluation/training activities will be maintained for each employee. MarkWest will assure that training is provided, as appropriate, under the following circumstances:

1. Initial assignment of duties.
2. Near miss (created as a direct result of operator error).
3. Observation of employee's action dictates need for additional training.
4. Whenever procedures (either regulatory or standard operating procedures) associated with the task change.
5. Three-Year Re-Evaluation
6. Disqualification
7. Employees who do not perform Covered Task duties for a period of six months will be re-qualified.

IDENTIFICATION OF COVERED TASKS

The determination of a covered task will be accomplished by use of the four-part test to include any activity identified by the operator that:

- Is performed on a pipeline facility,
- Is an operations or maintenance task,
- Is performed as a requirement of this part,
- Affects the operation or integrity of the pipeline.

Covered tasks are identified by reviewing **normal** and **abnormal** operating conditions (AOC's).

MAINTENANCE VERSES CONSTRUCTION

Maintenance includes those tasks required on a day-to-day basis to maintain the pipeline in its operational status. Operators of each pipeline system determine which tasks are to be included in their "Covered Task" list.

Typically, Operator Qualification does not apply to new construction until/unless the new construction includes any portion of a regulated system that is "in-operation". All aspects of the Operator Qualification program apply in those situations.

EVALUATOR QUALIFICATIONS

Persons conducting the evaluation process for MarkWest employees and sub-contractors (if applicable) will possess the skills and knowledge for the task being evaluated. In some circumstances, MarkWest may elect to contract with outside sources in order to accomplish these goals.

Some of the backgrounds that may qualify a person to be an evaluator include, but are not limited to, the following:

1. Extended education (college degree, trade school, etc.)
2. Skilled trade
3. Certification programs
4. Direct authorization from MARKWEST of a qualified person to teach
5. On-the-job experience

SUBSEQUENT QUALIFICATION INTERVALS

The subsequent qualification interval for any Covered Task shall not exceed 3 years.

PERFORMANCE BY NON-QUALIFIED INDIVIDUALS

Special circumstances may require non-qualified employees to perform covered-tasks for MarkWest. MarkWest will allow employees that have not been qualified to perform covered tasks provided they work under the direct supervision of a Qualified individual. The protocol for working in this manner is as follows:

1. The Qualified Person assumes responsibility for the proper performance of the task.
2. The Qualified Person must direct and observe the non-qualified person(s) and the covered-task being performed in order to take corrective action if necessary.
3. The Qualified Person can direct and observe up to seven (7) non-qualified persons at one time.

Non-Qualified persons cannot be directed or observed performing the following tasks. These tasks must be performed by a qualified person:

- Welding activities
- Hot Taps
- Field repair of pipeline by grinding or using full encirclement sleeve

VERIFICATION OF CONTINUED INTERVALS

1. If there is reason to believe that an individual's performance of a covered task contributed to an accident, the individual's qualification on that specific covered task will be suspended. The suspension will continue until that individual has either been re-qualified, or the subsequent investigation determines that the individual's performance did not contribute to the accident. In the interim, the individual may, at MarkWest's discretion, continue to perform other covered tasks that he or she is qualified to perform.

2. An Individual's qualification for a Covered Task(s) will be suspended for reasons including, but not limited to, unsatisfactory performance of a Covered Task or if the Operator or Contractor believes the Individual can no longer satisfactorily perform the Covered Task. The suspension will continue until that Individual is exonerated by the MarkWest. MarkWest will reserve the right to determine the method of re-qualification.

This Individual may continue to perform other Covered Tasks for which they are Qualified.

3. MarkWest will re-qualify Operators every 3 years.

MANAGEMENT OF CHANGE

This Program recognizes that substantive changes may occur which could affect the performance of covered tasks. Such changes must be evaluated and communicated to the personnel qualified to perform those tasks. The following describe changes that may require communication to individuals performing covered tasks.

1) Modifications to MarkWest Policies or Procedures. Any entity responsible for modifications that might potentially affect the performance of tasks must notify MARKWEST management.

2) Changes in State or Federal Regulations. MarkWest shall evaluate such changes for potential impact and, if necessary, make appropriate amendments to this program.

3) New Equipment and/or Technology. The responsible MarkWest manager shall notify the management personnel responsible for this program of any such changes that would affect the performance of a covered task. MarkWest will assure qualification, if required, is conducted on all personnel affected.

4) New Information from Equipment or Product Manufacturers. Any person becoming aware of such information shall notify MarkWest management responsible for compliance with this program.

5) Updated Task List. MarkWest will assure that compliance with the covered task list is maintained at all times. Changes, which affect personnel, will be documented.

If MarkWest management determines that these or any other changes would materially affect the performance of a task, it will oversee the modification of the qualification procedures for the affected task.

The Operator Qualification Manager will advise all affected qualified personnel of the task change. MarkWest's qualified examiner will ensure that previously qualified employees are qualified to incorporate the changes into their performance of the task. This will be documented in the documentation system.

MarkWest will update the appendices whenever a new covered task is identified. A copy of the updates appendices shall be submitted to the Pipeline Operator for review and approval.

CONTRACTOR QUALIFICATION

MarkWest will, from time-to-time, use contractors for various covered tasks. It is our policy to review both the qualifications of contractors and their qualification program, if applicable, and compare them to the covered tasks they will be assigned to complete. Contractors will be informed if their qualification program meets with the requirements established MarkWest by and regulatory agencies. MarkWest

Before contractors perform work for they will be required to participate in a pre-work safety orientation to review safety requirements for job tasks. MarkWest pipeline technicians will supervise contractors and are authorized to stop unsafe work practices immediately.

MarkWest may use contractors that are not qualified provided they are under the direct supervision of a qualified employee. The Qualified Person must remain in constant observance of the non-qualified person(S) and the covered-task being performed in order to take corrective action if necessary.

RECORDS

1) All recorded results predating the initiation of this program which have a bearing on qualification shall be maintained in their normal locations and retained for 5-years beyond the last date an individual is employed in a capacity that requires performance of the subject task.

2) All recorded results of qualification shall be maintained and retained for 5-years beyond the last date and individual is employed in a capacity that requires performance of the subject task.

3) All recorded results of qualifications to perform covered tasks shall include designation of each task as covered and the identity of the individuals qualified to perform them, the qualification date, and the evaluation method.

OPERATOR QUALIFICATION PROGRAM REVIEW

The MarkWest written Operator Qualification Written Program will be reviewed annually or when major changes are implemented, not to exceed 15 months.

SIGNIFICANT CHANGES TO THE OPERATOR QUALIFICATION PROGRAM

MarkWest will notify the Administrator or a state agency participating under 49 U.S.C Chapter 601 if the program is significantly modified after the Administrator or state agency has verified that it complies with this section.

MARKWEST OPERATOR QUALIFICATION EVALUATION

Employee Name: ______________________________

Job Title: ______________________________

Date of Hire: _____/_____/_____ **Years at this Job Title:** __________

Today's Date: _____/_____/_____ **Time:** __________ AM PM

Task Description: ______________________________

____

Name of Evaluator: ______________________________

Reason for Evaluation:
[ ] Initial Assignment of Duties
[ ] Three Year Re-Evaluation
[ ] Regulatory Change
[ ] Post Accident
[ ] Near-Miss
[ ] MARKWEST Standard Operating Procedure (SOP) Change
[ ] Results of Direct Observation Warrant Re-Evaluation

Evaluation Method: *(Check all that apply)*
[ ] Written Procedure [ ] Classroom/Training Study
[ ] Visual Observation

Evaluation Criteria: *(Check all that apply)*
[ ] Normal Operating Procedures [ ] Abnormal Operating Procedures
[ ] Manufactures Guidelines [ ] Other: __________

Attach the "Covered Tasks" list that this employee is "Qualified" to Perform to this sheet.

Based on the results of the Operator Qualification procedure the employee listed above is <u>"Qualified"</u> for performing the "Covered Task(s)" identified.

Qualifier Signature: ____________________ ____________________
Print Name ***Sign Name***

Qualified Employee Signature:

____________________ ____________________
Print Name ***Sign Name***

Refer to "Training" section for frequency of training and what warrants re-training.

Sheet___ ***of*** ___

EVALUATOR QUALIFICATION SUMMARY

Evaluator Name: ______________________________

Job Title: ______________________________

Qualification Summary: *(Check all that apply)*

[ ] I am familiar and knowledgeable of MarkWest's Standard Operating Procedures.
[ ] I am familiar and knowledgeable with normal operating conditions experienced with identified "covered tasks" that apply to MARKWEST operations.
[ ] I am familiar and knowledgeable with abnormal conditions that may arise from daily operations of the MARKWEST system.
[ ] I am familiar with the regulatory requirements of 49 CFR Part 195, specific to my operation and the "covered tasks" identified.
[ ] I am able to explain to the employee the reasons and justifications of the Qualifying process.
[ ] I have training and experience commensurate with the specific covered tasks from on-the job training provided by my employer.
[ ] I have training and experience commensurate with the specific covered tasks from extended educational training.
[ ] I have training and experience commensurate with the specific covered tasks from skilled trade programs.
[ ] I have training and experience commensurate with the specific covered tasks from certification programs.
[ ] I have training and experience commensurate with the specific covered tasks from task specific training programs.

Statement of Qualification:

The person listed above has been deemed qualified to function as an Evaluator for MARKWEST required under 49 CFR Part 195.

Re-Qualification will be required a minimum of once every three (3) years.

Authorized By MARKWEST:

Name: ______________________________
Print Name

____
Signature

Date of Authorization: ______/______/______

SCOPE	The Department of Transportation (49 CFR Part 192 and 195) requires pipeline operators to examine the exposed portion of buried pipelines to determine the coating condition and keep records of conditions found. If pipe under the coating is exposed, the pipe's external condition must be determined and records of the examination retained. MarkWest documents pipe condition on the Buried Pipeline Inspection Report Form 124. This procedure establishes a standardized method for examining and documenting the condition of an underground pipeline or related facility when exposed for any reason on Form 124.
OPERATOR QUALIFICATION	Operator Qualified field personnel performing work tasks or any other work tasks where the pipeline is excavated must complete Form 124. If there is an anomaly present, Operator Qualified field personnel (such as a Corrosion Technician or similarly trained individual) would be required to inspect the anomaly, measure it, and perform remaining strength calculations if applicable.
GENERAL INFORMATION-FORM 124	The data fields at the top of the form are for general information such as the line number, pipeline name, who inspected the pipe, etc. All fields must be completed. **Line Number/Name** – This is the company assigned line number/name. Example: **XYZ Line Station 1 to Station 2** **Inspected By** - Person or persons who examined the pipeline and completed the form. Example: **Name 1/Name 2** **Company** - MarkWest subsidiary to which that the pipeline segment is assigned. Example: MarkWest Energy Appalachia, L.LC **Region** - Field Operating Region in which the pipeline is located. Regions include **XYZ**. Example: TBD **Reporting Location** - This field would be the designated reporting location where a copy of the report would be retained for regulatory audits. Example: TBD **Date** - The calendar day and year the excavation and inspection took place. Example: 7/8/04

GENERAL INFORMATION-FORM 124 CONTINUED	**Legal Description** **Section/Block** - In states partitioned in section, township and range, the information is located on the inventory or alignment sheets. In states such as Texas, the data would be a survey and abstract number along the coastal region but section, township and range for West Texas. Example: Section/Block: 10 Township/Survey: 32N Range: 95W Example: Township/Survey: HT & B RR A-37 **County/Parish** - In all states except Louisiana, the named county where the pipeline segment is located. This information is also available on the alignment or inventory drawings for the pipeline. If the pipe segment is located in Louisiana, the county is a Parish. Example: County/Parish: Jefferson **State** - The state where the pipeline segment is located. Information available on the alignment or inventory drawings. The state can be spelled out or abbreviated. Example: WY **Reason for Inspection** **Encroachment/One Call** - If this data field is marked and there is no active pipeline corrosion, the form must be completed to and including the data box labeled Pipe – Inside Surface. The remaining data boxes labeled Cathodic Protection would be marked N/A. If active corrosion is present on any portion of the pipeline, Operator Qualified field personnel must complete the remainder of the form. **Construction** - Mark this box if the pipeline was exposed as part of a company construction project. **Leak** - Mark this box if the pipeline was exposed as part of a leak investigation. **Other** - Mark this box if the pipeline was exposed in conjunction with other work activities such as prove-up excavations as part of a smart tool survey. Example: Prove-up 2005 GE-PII Metal Loss Survey **Other Reports Completed** - Various other reports could be completed with the excavation. Identify those reports in this data field if applicable.
PIPELINE INFORMATION-FORM 124	The pipeline-specific data box contains detailed information on the exact location of the excavation, various operating conditions at the location and specific pipe details.

PIPELINE INFORMATION-FORM 124 CONTINUED	**HCA** – Check the box if the inspection area is within a High Consequence Area. If this is an excavation/repair that meets the criteria for an immediate or schedule repair (see IM-009 Pipe Repairs), check the appropriate box for the corresponding time. **Mile Post No.** – Pipeline mile where the excavation was performed. This is determined using the alignment or inventory drawings to confirm the excavation location. The mile location should be rounded to the nearest hundredth of a mile. On some pipeline systems, the pipeline mile post does not correspond to the inventory or alignment sheets. In such cases of discrepancy, a detailed description of excavation/repair location should be developed using known reference locations and measured distance so that it can be determined at a later date where the activity was performed. Example: Mile 24.01 **Rechain Sta.** - The exact survey rechain number, to the nearest foot, where the center of the excavation took place. Determine using the alignment or inventory drawings to identify the exact excavation location. Example: 8+29 **GPS Coordinates** – Global Positioning System (GPS) Coordinates include the latitude and longitude for an exact point on the face of the earth. Field personnel use a wide variety of manufacturers' hand-held equipment to gather GPS coordinates. The traditional method of labeling a coordinate is in degrees, minutes and seconds (39° 47' 23"). There are 60 seconds in a minute, 60 minutes in a degree. Most hand-held GPS units provide the degree and round the seconds into a decimal point (hundredth) as part of the minutes (39° 47.38') that is the preferred format for the form. Leave blank spaces for the degrees, minutes and seconds symbols. Latitude – The angular distance north of the earth's equator measured through 90 degrees. Example: N39 47.38 (for degrees included as part of the minutes format) Example: N39 47 23 (for notation of degrees, minutes and seconds format) Longitude – The arc or portion of the earth's equator intersected between the meridian of a given place and the prime meridian (as from Greenwich, England) and expressed in either degrees or time. Example: W93 39.44 (for degrees included as part of the minutes format) Example: W93 39 26 (for notation of degrees, minutes and seconds format) **Length of Line Uncovered** – Number of feet of pipeline actually exposed as measured at the excavation limits. Example: 80 feet

PIPELINE INFORMATION-FORM 124 CONTINUED	**Depth of Cover** – Depth in feet, to the nearest tenth of a foot, of overburden soil on top of the pipeline as measured at the excavation. Example: 3.0 feet **Year Line Installed** – The calendar year the pipeline segment was installed. This information is available in company records or on the alignment or inventory sheets. Example: 1947 **Pipe Size OD** – The pipe outside diameter in inches. For pipelines 16" and above, it will be a whole number. For pipelines 12" and smaller, it should be listed in inches and decimals. Examples include 4.5" for 4" nominal pipe, 12.75" for 12" nominal pipe, 8.625" for 8" nominal pipe. These sizes are published on the alignment or inventory drawings. Example: 8.265/ 24 **Pipe Grade (SMYS)** – The pipe grade and pipe specifications or actual pipe yield strength if known. As an example, API 5L X52, API 5L X60 and API 5L X42 are examples of pipe specified as API 5L pipe with varying grades, i.e. X52, X60 and X42. This information is available in company records and on the alignment or inventory drawings for the pipeline segment. If records are not available on the pipe grade or specification, write "unknown" in the data field. Example: API 5L X52 or ASTM A106 X42 Example: Unknown grade and specification **Operating Temperature** – The operating temperature is specific to where the pipeline segment is located, such as downstream of a processing plant, compressor station or other input point with higher than normal operating temperatures. The maximum temperature a pipeline should be exposed to is 135° F. Generally, gas flowing in the pipeline and not exposed to a heat source will be between 50 and 60° F. Measurement personnel in the Region can provide this information and company records will also have a mean average temperature listed for a pipeline segment. Example: 60 (shown in ° F) **MOP/MAOP Pressure** – The maximum allowable operating pressure at which a pipeline or segment of a pipeline may be operated under DOT Part 192 (MAOP-gas) and 195 (MOP-liquids) regulations. This information is available in the O&M Procedures Manual for all pipeline segments. For liquid pipelines, MOP will vary with distance due to elevation profile (static head). Contact engineering to determine MOP at a given location on a liquid pipeline. Example: 696 psi

GEOGRAPHIC INFORMATION-FORM 124	This data box contains information relative to the type of land use where the pipeline segment is located. This information could change due to urban sprawl or farming operations. The information is needed for performing risk assessment and for determining possible corrosion conditions to the pipeline or soil stresses that could be present on the pipeline coating. **Soil:** These boxes going from left to right indicate the most prominent soil types. Select only one and the most prominent. Clay - Soil that is plastic or gummy when wet Loam - Loose, well-aerated soil composed of clay, sand and organic matter Rock - Mineral matter in masses of stony materials Sand - Debris of rocks consisting of small, loose grains Silt - Very fine sand or loose material often deposited as sediment by moving water such as a river Other - Could include examples such as: Muck - highly organic, moist soil mainly composed of manure or decaying vegetable matter; Cinders - coarse residue of combustion, such as ashes, clinker-like lava or slag from refining metals; Caliche - a flake-like soft limestone that forms in arid regions. **Land Use:** Mark one box going from left to right that indicates the corresponding land use surrounding the pipeline segment. Cultivated - Land used agriculturally for raising crops Pasture - Grassland used for grazing animals Wooded – Tree-covered lands Urban - Land used mainly for homes, business firms, streets and related to typical city environments Other - Land used for any other purpose, such as: Industrial - land used for manufacturing such as refineries, chemical plants, power plants, etc.

GEOGRAPHIC INFORMATION-FORM 124 CONTINUED	**Topography:** Mark one box going from left to right that indicates the nearest matching description of the surface environment around the pipeline. Level - Flat plains area Rolling - Region of gentle slopes Rough - Uneven or rocky terrain with rugged hills or breaks in the surface features River Bottom - Located in the flood plane of a river or stream Swampy – Wet, spongy land saturated and sometimes partially or intermittently covered with water Other - Any description that describes the land topography not listed above **Drainage:** Mark one box from left to right for the quality of water drainage in the vicinity of the pipeline. Good - Typically no standing water; groundwater table below pipeline depth Fair - Typically no standing water, high groundwater table Poor - Typically standing water and/or groundwater table near the surface **Backfill:** Mark the box from left to right that corresponds to the condition of the soil covering the pipeline. Loose - Unpacked cover that is easily displaced Settling - Cover that has sunk below the surrounding surface Compact - Well-packed surface with firm and stable appearance

EXTERNAL COATING-FORM 124	This data box must be completed for all exposed pipe. Much of the coating information is on alignment or inventory drawings and is located in company records. Perform an inspection of the pipe coating, if coated, and note the type of coating. Most of the general coating information can be found on alignment sheets. **Year Coated** - This calendar year could correspond to the year the pipeline was constructed or it could be related to the year that the pipeline was re-coated or rehabilitated. Example: 1967 **Manufacturer** - The company that manufactured the pipeline coating. Coating Pipelines and the information is generally available in company records or on some alignment or inventory drawings. Example: Koppers **Generic Type** - Generic types include Coal Tar Enamel, Fusion Bonded Epoxy (FBE), Asphalt, Tape, etc. Example: Coal Tar Enamel **Coal Tar, Asphalt Enamel, Tape Product Condition** - Check one or more of the boxes from left to right that apply. Most coal tar enamels and asphalt enamels have an outer wrap of felt that could contain asbestos. If records indicate that the coating had felt, mark the Yes box. If records indicate that the outer wrap contains asbestos, mark the box Yes. If it is unknown whether the felt contains asbestos or whether the coating had a felt outer layer, mark the box Unknown. These records are available at the reporting locations, regional offices, on the inventory or alignment sheets or in company records. Good Condition - The coal tar enamel, asphalt enamel or tape product coating is bonded to the pipeline and intact. Disbonded - The coal tar enamel, asphalt enamel or tape product is not bonded to the pipeline and may hang in loose pieces from the pipeline. The coating might be surrounding the pipeline but separated by a layer or membrane of water between the coating and pipeline. Soil Penetration - Surrounding soil has penetrated the coal tar enamel, asphalt enamel or tape product and is possibly making contact with the pipe surface. Caliche soils or rock/gravel soils have the characteristic of penetrating the pipeline coating. Wrinkled - The coal tar enamel, asphalt enamel or tape product is distorted into wrinkles rather than having a smooth surface. These coatings typically are "soil stressed" in heavy clay soils or loam soils subjected to drying and wetting conditions including extreme temperature variations from season to season.

EXTERNAL COATING-FORM 124 CONTINUED	Cracked - Damaged due to brittleness that leaves the surface appearance as broken similar to fractured glass. The coating is broken apart into segments that may still be bonded to the pipeline. **Thin Film Epoxy (FBE) Product Condition** - This data field list two boxes to describe thin film epoxy (also known as fusion bonded epoxy) coated pipelines condition, either Good or Poor. Good - Mark the box if the coating surface is intact and bonded to the pipeline. The surface could contain blisters that do not penetrate to the pipe surface. Poor - Mark the box if the coating is damaged and any amount of the pipe surface is exposed. The damaged coating could be from high heat, blisters, over voltage from cathodic protection causing coating to be disbanded near a small holiday, flaking or no coating adhesion due to poor application practices at the coating mill.
PIPE-OUTSIDE SURFACE-FORM 124	If the pipeline coating was intact and no pipeline steel was exposed due to damaged pipeline coating, document in the "Description of Activity/Repair" section. If the pipeline steel is exposed due to damaged coating, complete this data box. If active corrosion is observed, call a corrosion technician or similarly trained and Operator Qualified person to complete the remainder of the form. See the "Corrosion Assessment" and "Corrosion Pit Interaction Rules" sections of this procedure for evaluation requirements. **Corrosion Condition** - Mark the box from left to right that best describes the type of corrosion found on the pipeline steel. No Corrosion - Mark this box if the pipeline steel is exposed but there is no corrosion. If no active corrosion is present, no other data in this data box needs to be completed. General (Sheet) Corrosion - A thin layer of shallow rust on the pipe surface distributed more or less uniformly over a given area. Pitting - An isolated individual metal loss indention (pit) penetrating the pipe surface typically deeper than 10% of the pipe body wall. Corrosion is confined to a point or small region and is in the form of pits. **Clock position in direction of flow** - The circumferential location of the corrosion as related to the clock position. Looking in the direction of gas flow, the 12 o'clock position is top dead center (top) of the pipeline, 3 o'clock is clockwise to the right, 6 o'clock is exactly on the bottom and opposite of the top of the pipeline (12 o'clock) and 9 o'clock is on the left side opposite of 3 o'clock.

PIPE-OUTSIDE SURFACE-FORM 124 CONTINUED	<u>**Corrosion Dimensions**</u> This information, along with the specific pipe information completed in the pipe characteristics box above is required to complete remaining strength calculations. **Longitudinal Length of Corrosion** - Determine the longest length of the corrosion in accordance with the "Corrosion Pit Interaction Rules" section of this procedure. Complete the blank using whole inches and decimals to one thousandth. Examples include 3.5" or 0.365" if less than one inch long. Example: 0.250 inches Example: 6.34 inches **Corrosion Depth** - Deepest penetration into the pipe body wall in decimals to the thousandth. Example: 0.070 inches **% Depth** - Percent depth penetration into the pipe body wall. The depth of deepest corrosion is divided by the nominal wall thickness data located in the Pipeline Information section of the form times 100. Example: Wall thickness: 0.344" Depth of deepest corrosion: 0.250" - 0.250/0.344 x 100 = 72.6 or rounded to 73%. Round to the nearest whole number. Example: 73% **Stress Corrosion Cracking (SCC) Inspection Performed -** Mark the box Yes or No if an SCC inspection was performed using non-destructive testing techniques. If the test was performed, mark the box Yes or No to indicate whether stress corrosion cracking was found using the testing technique. **SCC Testing Performed** - Identify by marking the non-destructive method used to determine whether stress corrosion cracking was found on the pipe surface. Black/White Contrast - Mark the box if the black on white contrast magnetic particle inspection procedure was used to develop the stress corrosion cracks. Magnetic Particle - Mark the box if the dry powder magnetic particle inspection procedure was used to develop the stress corrosion cracks. Wet Fluorescence - Mark the box if the wet fluorescence magnetic particle inspection procedure was used to develop the stress corrosion cracks. **SRB Check** - Indicate by marking the box Yes or No whether a field or laboratory test was performed to detect Sulfate Reducing Bacteria. Provide the results in colonies per milliliter. Example: 10,000

PIPE-OUTSIDE SURFACE-FORM 124 CONTINUED	**APB Check** - Indicate by marking box Yes or No whether a field or laboratory test was performed to detect acid producing bacteria. Provide the results in colonies per milliliter. Example: 100,000 A procedure for bacteria testing is provided in the "Bacteria Testing" section of this procedure.
PIPE-INSIDE SURFACE-FORM 124	This data box is only applicable when the pipeline segment has been removed and the inside of the pipe can be visually inspected. It also applies if a hot tap coupon has been removed from the pipeline for inspection. If the pipe inside surface is not exposed during the excavation, mark the box N/A. If active corrosion is present, a corrosion technician or similarly trained / qualified personnel must complete the remainder of the form. **Corrosion Condition** - Same descriptions as in the PIPE - OUTSIDE SURFACE data box above. **Corrosion Dimensions** - Same descriptions as in the PIPE - OUTSIDE SURFACE data box above. **Field Test Performed** - If fluids were collected from inside the pipeline, mark the appropriate boxes relative to tests performed and the results. **Fluid pH** - The pH determined from field testing or laboratory testing fluids removed from the inside of the pipeline. A pH of 7 is neutral and low numbers indicate acid conditions while high numbers indicate alkaline conditions. Provide the number in decimal format with one-tenth accuracy. Example: 7.6 SRB Check - Indicate by marking the box Yes or No whether a field or laboratory test was performed on fluids removed from the pipeline to detect Sulfate Reducing Bacteria. Provide the results in colonies per milliliter. Example: 10,000 APB Check - Indicate by marking box Yes or No whether a field or laboratory test was performed on fluids removed from the pipeline to detect acid producing bacteria. Provide the results in colonies per milliliter. Example: 100,000 A procedure for bacteria testing is provided in the "Bacteria Testing" section of this procedure.

Comment [MAC1]: Need to be added to form 124 (APB/SRB)

CATHODIC PROTECTION-FORM 124	This data box does not have to be completed if there is no active corrosion or evidence of stress corrosion cracking on the pipeline. An Operator Qualified person would be required to complete this data box if there was active corrosion or evidence of stress corrosion cracking on any portion of the exposed pipeline. **CP System On or Off** - Mark this box if the cathodic protection system impacting the pipeline segment excavated is on and in service or mark the No box if the cathodic protection rectifiers were shut off during the excavation. **Distance from nearest rectifier** - Determine the rechain number for the nearest rectifier unit and provide the distance from the excavation to the rectifier either in feet or miles. If provided in feet, format to the nearest whole number. If provided in miles, format to the nearest tenth of a mile. Example: 867 Feet Example: 1.3 Miles **Rectifier Number/Name** - Many company rectifiers have numbers assigned to them. Others are listed by their name related to location. Example: R-5362 Example: Road Crossing 238 **Pipe/CUSO4 Potentials** - Provide pipe to soil survey potentials in millivolts (four whole numbers) relative to a copper-copper sulfate electrode. Ground Level - The pipe to soil potential taken at the surface directly over the pipeline in undisturbed soil. Example: -1533 mV Over Pipe - The pipe to soil potential taken as close as possible in soil directly on top of the pipe in the excavated ditch. Example: -1505 mV Under Pipe - The pipe to soil potential taken as close as possible in soil directly underneath the pipe in the excavated ditch. Example: -1510 mV **Soil Resistivity at Pipe Depth** - The soil resistivity in ohm-cm taken at pipeline depth using an instrument such as the M. C. Miller Soil Resistivity Meter or from a soil sample collected and preserved from pipeline depth and tested for resistivity using a soil box. See the "Soil Resistivity Testing" section of this document for a procedure. Example: 35,000 Ohm/cm **Soil Moisture Content** - Mark the box that best indicates the water content in the soil at the time of the excavation. Wet - Mark this box if the soil is saturated with water and water drips from the sample if held in your hand.

CATHODIC PROTECTION-FORM 124 CONTINUED	Dry - Mark this box if the soil is dry with no water present. No water drips from the soil if the soil sample is held in your closed fist. Moist - Mark this box if water is present but not saturated. Water drips from the soil sample if you close your fist containing the soil and press water from the soil. **Soil pH** - The soil pH determined from field testing. A testing procedure is provided in the "pH Testing" section of this procedure. A pH of **7** is neutral and low numbers indicate acid conditions while high numbers indicate alkaline conditions. Provide the number in decimal format with one-tenth accuracy. Example: 7.6
OTHER-FORM 124	Use the Description and Notes sections to provide inspection details not requested in the form data boxes. Information to provide includes how much pipe was cut and replaced, from rechain to rechain, type of pipe used for replacement, type of coating used to make repairs, from what rechain number to where; whether the coating sample was sent to a lab for determining asbestos content; whether this pipeline location had been excavated before and why; more detail as to the pipeline coating condition; more detail on types of corrosion or mechanical defects found, NDE results, repair method used etc. Digital photo documentation of the exposed pipeline should be taken before, during and after the inspection/repair. The pictures should be in focus and be high resolution. Pictures of anomalies should be attached to Form 124 and specifically include pictures of located anomalies and associated details (where applicable) required from this procedure. Attach pictures, results and schematics as necessary to fully document the activity and associated results.
EXCAVATION OF PRESSURIZED LINES	Only qualified personnel can oversee and perform one-call notifications, line locating, marking, trenching, and backfilling operations. Company personnel and contractors must be Operator Qualified in accordance with the Company OQ Plan in order to perform excavation related work. A qualified individual is one who has been evaluated and can perform assigned covered tasks and can recognize and react appropriately to abnormal conditions. Before excavation, the line must be located with a water probe, probe rod, vacuum truck or exposed by hand. If a probe rod must be used, inspecting the coating in the excavated area is required and any damaged areas must be repaired before backfilling. DO NOT locate pressurized lines using power equipment.

EXCAVATION OF PRESSURIZED LINES CONTINUED	Power equipment excavation should be done parallel to the pipeline unless right-of-way congestion prevents adequately positioning excavating equipment. Digging across the line with power equipment should be avoided wherever possible. Do not operate power equipment closer than 12-inches to the line. Remove material less than 12-inches from the pipeline by hand or by crumbling the material into the ditch by hand so power equipment can remove it. A spotter will work with the equipment operator to ensure the pipeline or coating is not damaged. Report any damage to the pipeline to the Company's supervisor immediately.
PIPE DEFECTS, DAMAGE OR CORROSION	Refer to IM-009 Pipe Repairs for the appropriate repair and mitigation procedures for a specific anomaly type. In certain circumstances, a pressure reduction may be required if it is determined that an unsafe condition exists. The Pipeline Integrity Engineer should be contacted immediately upon identification of any anomaly associated with the pipe including: corrosion, dent, mill defect, leak, etc.

CORROSION ASSESSMENT

The assessment of corrosion pitting for fitness for service involves documentation of the maximum depth and longitudinal length of interacting areas of wall loss, often using a pre-determined grid (e.g. 1" axial x 6t, where t is wall thickness). The cumulative length of interacting areas in the grid and the maximum depth of wall loss are measured and used to determine a cross sectional area of wall loss which is then used to evaluate a safe operating pressure.

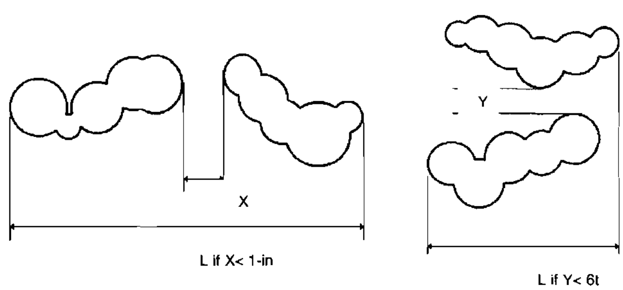
Remaining strength (safe and burst pressure) is calculated in accordance with IM-009 Pipe Repairs.

Corrosion Evaluation

a. Identify all corrosion with a depth greater than 10% of nominal wall thickness.
b. Measure and record wall thickness around the corroded area(s), compare with nominal wall thickness and use for burst pressure (safe operating pressure) calculations if the measured wall thickness is different than the nominal wall thickness.
c. Sequentially number each area from left to right and top to bottom.
d. Measure and record the length of each area.
e. Determine if interaction occurs, and define the total area that needs to be measured.
f. Map the selected corroded areas using a grid (see guidelines for grid size below)
g. Record a maximum pit depth or the minimum remaining wall thickness in each square of the grid.

Longitudinal Length of Corrosion Area	Size of Grid
< 2-in	0.2-in
≥2-in	0.5-in

CORROSION PIT INTERACTION RULES	Often corroded areas may be closely spaced. Depending on the proximity to each other, these areas may act individually or they may interact to form a larger corrosion area that behaves as a single, more severe defect. The Company currently has adopted a 1-in axial x 6t circumferential (t= wall thickness) interaction rule criteria. Corrosion located within these distances is considered to interact and should be considered to be a single anomaly. To calculate burst or safe operating pressure with B31G, Modified B31G or RSTRENG, the length and depth of the associated area is required. A profile or river bottom path of the corrosion must be recorded. Measurement will consist of axial increments along the axial extent of the corrosion starting from the furthest up stream position of corrosion. The profile of the corrosion area is made by plotting points to create a 'river bottom path' on the contour map. Each increment (column) is then inspected ultrasonically or via pit gauge in order to identify the maximum metal loss and is recorded. At a minimum, the length and maximum depth of corrosion (including considerations for interaction) are required to perform a remaining strength calculation (safe operating and burst pressure).



	When the interaction between corrosion areas is difficult to determine or questionable, corrosion assessment should assume interaction to ensure a conservative methodology. If the internal portion of the pipe is exposed from being cut, coupon extracted, or other reasons, include the internal surface in the corrosion examination. For pipe cutouts, examine and note the internal condition of the adjacent pipe ends and document on Form 124.

BACTERIA TESTING **(SERIAL DILUTION METHOD)** **CONTINUED**	This procedure outlines the proper sequence of steps to correctly culture/test for the presence of various strains of corrosion causing bacteria. Bacteria testing will be performed on buried pipelines anytime external or internal corrosion is identified. In addition, bacteria testing will be performed to determine internal corrosion risk as deemed necessary by the Area Manager. To minimize changes, the sample should be analyzed without delay, preferably on site. If a delay of more than one hour is unavoidable, a glass container should be used; however it should be noted that errors in bacterial population estimates still could result. Samples to be held more than four hours should be refrigerated (4° C or 39.2° F). Samples held for longer than 48 hours, even under refrigeration, are of dubious value. ***Solid Samples (e.g. nodules, corrosion product, soil, etc.)*** Wear sterile surgical Gloves at all times during the following procedure. Remove approximately ½ teaspoon of material to be tested using a sterile tongue depressor or an alcohol – sterilized knife/tool. Add the previously removed materials to a sterile/new collection vessel made of glass, polyethylene or polypropylene which contains enough anaerobic diluting solution (ADS) to dilute the solids sample yielding enough liquid to extract enough 1.0 ml samples to inoculate the various types of test medium being utilized. Replace an uncontaminated cap on the collection vessel and shake vigorously to homogenize the sample. Proceed to Inoculation of Media ***Samples of Surface Scale or Biofilm*** Dip a sterile cotton swab into anaerobic diluting solution (ADS) and swab an area of approximately one square inch of test specimen. Place swab into collection vessel containing anaerobic diluting solution (ADS) and break off excess. Replace an uncontaminated cap on the collection vessel and shake vigorously to homogenize the sample. Proceed to Inoculation of Media

BACTERIA TESTING (SERIAL DILUTION METHOD) CONTINUED

Liquid Samples

Collect enough water from the system being tested to be able to extract enough 1.0 ml samples to inoculate the various types of test medium utilized.

Proceed to Inoculation of Media

Inoculation of Media

Label media vials 1, 2, 3, 4, 5, etc. in each string of media before sampling. Be sure to record the test date, time and location of the sample for future reference. Additional sample information such as temperature and pH are also desirable. The inoculation media and incubation temperature should be within ±5°C (±9°F) of the recorded temperature of the water when sampled.

Remove the metal center tabs from the top of the media vials without removing the metal seals. Sterilize the rubber septum with an alcohol swab.

Using a 3.0-ml plastic syringe with 24-mm (1.0-inch) 22-gauge needle attached, remove 1.0-ml sample to be inoculated. Insure that all air is removed by inverting the syringe, evacuating excessive sample liquid and tapping the side of the syringe, if necessary.

Insert the syringe through the rubber septum and inject the 1.0-ml sample into vial # 1.

Without removing the needle from the vial, withdraw 1 to 2 ml of the medium/sample and inject it back into the vial. Repeat this several times. This procedure rinses the syringe of the remaining sample and simultaneously mixes the contents of the vial.

With a new sterile syringe, remove 1.0 ml of mixture from vial # 1 and inject the sample into vial # 2. Repeat step 5.

Continue this procedure for each of the remaining vials in the string using the same syringe used for vial # 2.

Inoculate all other growth media strings utilizing the same procedure described above. Remember to use a fresh syringe when inoculating a different growth media string.

Discard syringes and needles.

BACTERIA TESTING (SERIAL DILUTION METHOD) CONTINUED

Incubate all vials of media at system temperature and out of direct sunlight. Check the vials as follows:

- Aerobic and Anaerobic Acid Producing media – after a minimum of five days or a maximum of 14 days
- Sulfate Reducing and General Anaerobic media – after a minimum of 21 days

Interpretation of Results

Positive results are as follows:

Media	Positive
Aerobic Acid Producers	Media Turns Yellow
Anaerobic Acid Producers	Media Turns Yellow
General Anaerobic Bacteria	Media Turns Turbid
Sulfate Reducing Bacteria	Black Material Forms

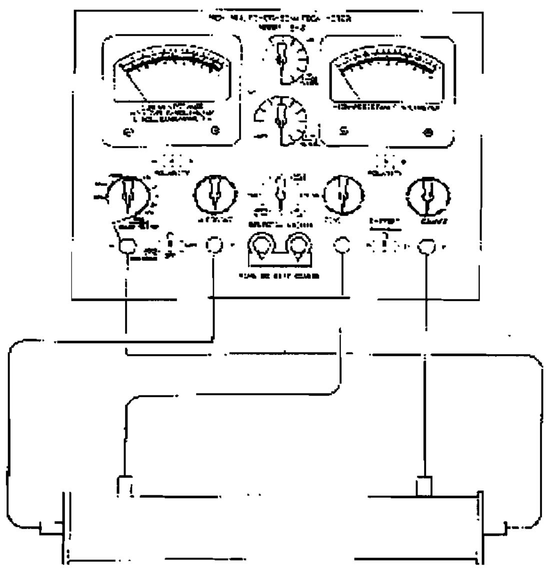
The number of vials that show positive results in the allotted time period can be used to calculate/quantify the bacteria level in the original sample by means of the following table:

Number of Positive Vials	Bacteria, Colonies/ml
1	1 – 10
2	10 – 100
3	100 – 1,000
4	1,000 – 10,000
5	> 10,000 – 100,000

When sampling a system with H_2S present, sulfate reducer nutrient vial No. 1 will often turn positive (black) within 15 to 60 seconds of inoculation. This occurrence should be considered "no growth" if only this vial is turned after 21 days. If vial No. 2 turns black immediately, a new sample of water should be obtained and purged with nitrogen to remove the H_2S.

BACTERIA TESTING (SERIAL DILUTION METHOD) **CONTINUED**	**Definitions** Acid Producing Bacteria (APB) – Any organism that metabolically produces weak acid concentrations; includes a variety of microorganisms Anaerobic Diluting Solution (ADS) – A solution used to dilute solids samples to enable it to be inoculated as a liquid for the serial dilution technique. Aerobe – An organism that requires oxygen to live. Anaerobe – An organism that lives without oxygen. Biofilm – A thin film/layer attached to the metal substrate and usually comprised of various strains of microorganisms. Colony – A visible growth of microorganisms on or in a medium. Culture Medium – Any nutrient system for the artificial cultivation of bacteria or other microorganisms, usually a mixture of organic and inorganic materials. Inoculation – The act or process of the introduction of a bacteria sample into a medium to stimulate growth. Microorganism – Any organism of microscopic size that requires a microscope to be seen. Nodule – A small mass/swelling of rounded or irregular shape containing bacteria; normally includes a variety of microorganisms. Replacement-In-Kind – A replacement that equals or exceeds the original design, operating and/or technical specifications and requirements. Sterile – Free of any living organisms.
SOIL RESISTIVITY TESTING	This procedure outlines the proper sequence of steps needed to conduct soil resistivity testing for the use in site selection and design of cathodic protection facilities and electrical grounding cells.

SOIL RESISTIVITY TESTING CONTINUED	**<u>Determining the Need for Soil Resistivity Testing</u>** Determine on an as-needed basis the applicability and benefit of resistivity testing on soils located on or in the vicinity of any Company pipeline facility. The need for soil resistivity testing shall be based on, but not limited to, the following: No history or knowledge of soil resistivity in an area No history or knowledge of the CP system complete circuit resistance for an area Limited or questionable CP current spread over pipeline systems in an area History of lightning damage in an area Electrical grounding requirements in an area **<u>Selecting Test Locations</u>** Obtain maps, alignment sheets, drawings, etc., of the area in question. Select possible test sites from the map data. Conduct field/location/site survey. **<u>Conducting Soil Resistivity Test Using a Soil Box and a M.C. Miller B-3 Meter</u>** Obtain a one-gallon sample of the soil to be tested (enough soil to fill the soil box at least three times, in the event that the test must be repeated.) Place/store/transport the soil sample in a clean plastic or glass container, sealed to retain the original soil moisture. Prepare the soil box and soil sample for the test. Make sure the soil box is clean and free of all foreign matter, including hydrocarbons and fluids. If the soil box is equipped with insertion potential pins (probes) in lieu of side contact points, remove the pins before loading the box.

SOIL RESISTIVITY TESTING CONTINUED	Overfill soil box and press (compact) soil with lid (or straight edge if box is not equipped with a lid). If the soil sample is very loose, it may need to be compacted several times before running the test. If the soil sample is dry, add distilled water to assist in compacting the soil into the soil box. Insert potential pins (probes), if required by box type, into the soil box. Connect the M.C. Miller Model B-3 meter to the soil box, as shown:  **FIGURE 1** Soil Box with M.C. Miller B-3

SOIL RESISTIVITY TESTING CONTINUED	Check the Miller B-3 to ensure proper working condition. Set the switches in the shorted (normal) position and the polarity switches in positive mode. Connect a test lead from the negative LR (Low Resistance) terminal to one end (current) terminal on the soil box. Connect a test lead from the positive LR terminal to the other end (current) terminal on the soil box Connect a test lead from the negative HR (High Resistance) terminal to the inside pin (potential) terminal on the soil box closest to the end where the positive LR connection was made. Connect a test lead from the positive HR terminal to the other inside (potential) terminal on the soil box. Conduct the test by taking voltage and amperage readings. ♦ Set selector switch to the HR with Bias position. ♦ Slowly turn the HR meter range switch counterclockwise to the lowest range without throwing the HR meter needle off scale. ♦ To balance the HR voltmeter with the bias knobs (located at bottom center of B-3 panel): i. Turn the DC Bias-Fine control knob clockwise to the "On" position. ii. Turn the DC Bias-Coarse control knob until the HR meter needle is on 0 (zero). iii. Fine tune the HR meter by turning the Fine control knob until the HR meter needle is exactly on 0 (zero). ♦ Turn the LR meter range switch to the Amps position. ♦ Set the current toggle switch (located at bottom left of panel) to the Amps with Controls position. ♦ Ensure that the Rheostat control knob (located under the LR meter) is turned to a fully clockwise position, and that the Fine and Coarse HR control knobs (located under the HR meter) are turned to a fully counter-clockwise position.

SOIL RESISTIVITY TESTING CONTINUED	♦ Set the ampere range switch (located at the lower left of the panel) to the 1A position. ♦ Set the Battery Toggle switch (located at the bottom right of the panel) to the 3 V position. ♦ Slowly turn the Fine and Coarse control switches clockwise to increase the current output, measured on the Milliamp meter (LR meter) to a fixed output of less than 1 amp, while at the same time observing the HR meter to assure that the meter needle does not go off scale. When the HR meter needle nears the scale limit, switch the HR range to the next higher scale. When the current output becomes less than 0.2 Amps, set the ampere range switch on the lowest applicable scale. ♦ Read and record the fixed current output reading indicated on the milliamp meter and the voltage reading indicated on the HR meter. Make certain the current has not drifted from the fixed value. If necessary, readjust the current with the fine and coarse control switches. After adjustments, read and record the amperage and voltage again. ♦ Check the DC Bias control by interrupting the current. Turn the Battery toggle switch from 3 V to Off and observe if the meter needle on the HR meter returns to O. If it does not return to O, adjust the meter needle to O with the DC Bias control knobs. ♦ Turn the Battery toggle switch back to 3 V and repeat the previous three and two steps until the HR meter returns to 0 when the current is interrupted. ♦ Record the final current (I) and voltage (E) readings in a field note book. After completing the test, turn the Battery toggle switch Off. Set all the B-3 switches to the Off or S positions and all other controls at their original positions. Empty and clean the soil box, and store in a dry plastic bag or container. Calculate the soil resisitivity by using the formula: SR (Soil Resistivity) (ohm/cm3) = E (Millivolts) / I (Milliamperes)

SOIL RESISTIVITY TESTING CONTINUED

<u>Conducting Soil Resistivity Test using the Wenner 4-Pin Method and a Nilsson Model 400 Resistance Meter</u>

Install the four resistivity ground pins (probes) at test site.

Pin spacing should directly correlate to the depth of the test. For example, to test the soil at a ten-foot depth requires the pins to be spaced at 10' intervals.

Lay out pin spacing, in a straight line and at equal distance apart based on the soil depth being tested, as shown in Figure 2.

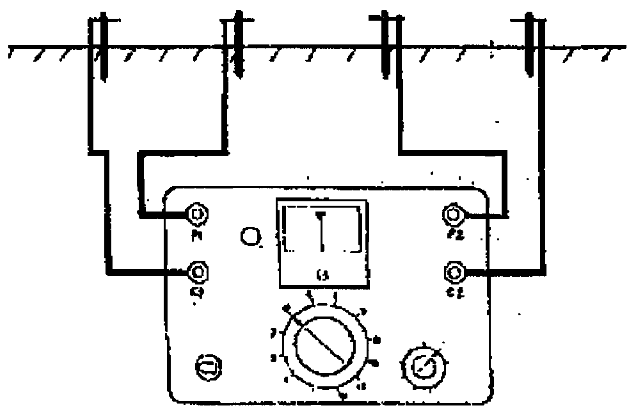


FIGURE 2
Wenner 4 Pin with Nilsson M-400

Inspect the pins to ensure the test pins are bright/shiny to eliminate contact resistance.

Drive the pins into the ground to a depth of approximately 6". If the 6" depth can not be obtained with all 4 pins, install all pins at the same depth.

Connect the Nilsson Model 400 Soil Resistance meter, as shown in Figure 2.

Check the Nilsson M-400 to assure proper working condition.

Set the meter in the middle of the pin line.

SOIL RESISTIVITY TESTING CONTINUED	Connect a test lead from the C-1 meter terminal (left side of the meter) to the first (outside) ground pin (left side of the lay out). Connect a test lead from the P-1 meter terminal (left-top side of the meter) to the second (inside) ground pin (left side of the lay out). Connect a test lead from the P-2 meter terminal (right-top side of the meter) to the third (inside) ground pin (right side of the lay out). Connect a test lead from the C-2 meter terminal (right side of the meter) to the last (outside) ground pin (right side of the lay out). Conduct the soil resistivity test. ♦ Set the Range Selector switch to the highest position. ♦ Turn the Potentiometer knob as far clockwise as possible. ♦ Press the Null Sensitivity button and observe the meter needle swing (direction should be to the right). This process will help protect the meter from under sensitive over swing damage. ♦ While pressing the Null button, slowly turn the range selector downward to lower ranges, observing the meter needle swing at each setting. ♦ When the meter needle moves to the left side of the center of the dial, back up one range setting. ♦ While toggling the null button off and on, slowly turn the potentiometer knob counter-clockwise until the meter needle is centered in the dial. ♦ If the potentiometer knob is close to zero (almost fully counter-clockwise), back up one range setting and repeat step 3 of this procedure. This will result in a more accurate reading. ♦ Some meters are equipped with a Low/High sensitivity toggle switch. With these meters, first conduct the test in the Low sensitivity mode. Then use the High sensitivity mode to refine the reading. This will result in a more accurate reading. ♦ When the meter needle is centered (balanced), record the potentiometer dial reading and the range switch setting in a field note book. Also record the pin spacing.

SOIL RESISTIVITY TESTING CONTINUED	After completion of the test, turn the Potentiometer knob to the maximum clockwise position and set the Range Selector switch to the highest position. After recording the pin spacing, remove the pins. Clean the pins and store them in a clean plastic or wood container. Calculate the Soil Resistivity: Resistance (R) = 8.7 X .1 = .87 ohms Example: POTENTIOMETER dial = 8.7 & Range setting = .1 Calculate the soil (ground) resistance (R) by multiplying the potentiometer dial reading by the range switch setting. Determine the pin spacing multiplier (PF) (pin factor, spacing factor or distance factor) based on 1' = 191.5 Example: 10' pin spacing has a multiplier of PF = 10 X 191.5 = 1915 Calculate the soil resistivity by using the formula: SR (Soil Resistivity) (ohm-cm) = PF X R or SR = 191.5 X D (Dist. between pins in ft) X R Example: For a pin spacing of 10 ', potentiometer dial reading of 8.7, Range setting of .1 : SR = 1915 X 0.87 = 1666.050 or 1666 ohms-cm or SR = 191.5 X 10 X 0.87 = 1666 ohms-cm

SOIL RESISTIVITY TESTING CONTINUED

Conducting soil resistivity test using a soil box and a Nilsson M-400 meter

Obtaining the soil sample, preparing the soil box and loading the soil sample should follow steps 1 through 6 of the :Soil Box and M.C. Miller B-3 Meter procedure.

Connect the Nilsson Model 400 Soil Resistance meter, as shown in Figure 3.

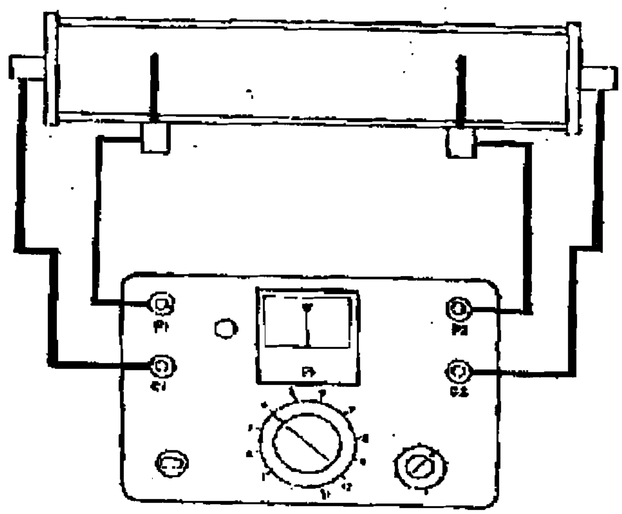


FIGURE 3
Soil Box with Nilsson M-400

Check the Nilsson M-400 to assure proper working condition.

Set the meter in front of the soil box.

Connect a test lead from the C-1 meter terminal (left side of the meter) to the left end (current) terminal on the soil box.

Connect a test lead from the C-2 meter terminal (right side of the meter) to the right end (current) terminal on the soil box.

Connect a test lead from the P-1 meter terminal (left-top side of the meter) to the left inside (potential) terminal on the soil box.

SOIL RESISTIVITY TESTING CONTINUED	Connect a test lead from the P-2 meter terminal (right-top side of the meter) to the right inside (potential) terminal on the soil box. Conduct the soil resistivity test. Follow step 13 of the "Wenner 4-Pin Method and a Nilsson Model 400 Resistance Meter" portion of the procedure. Empty and clean the soil box, and store it in a dry plastic bag or container. After recording the pin spacing, remove the pins. Clean the pins and store them in a clean plastic or wood container. Calculate the soil resistivity. To determine the soil (ground) resistance (R), multiply the potentiometer dial reading by the range switch setting. Example: potentiometer dial = 8.7 & range setting = .1 Resistance (R) = 8.7 x .1 = 0.87 ohms Determine the soil box pin multiplier (PF) (pin factor or distance factor) by either: The PF stamped on or assigned for the soil box or, The distance (tenths of feet) between the inside (potential) terminals on the box and using 0.1 ' = 19.15. Example: 0.5' pin spacing has a multiplier of: PF = 0.5 X 191.5 = 95.75 Calculate the soil resistivity by using the formula: SR (Soil Resistivity) (ohm-cm) = PF X R Example: Pin spacing of 0.5', Potentiometer dial reading of 8.7 Range setting of .1 : SR = 95.75 X 0.87 = 83.30 or 83 ohm/cm3 Record soil resistivity test results on the field notes and/or any specific form requiring this information.

PH TESTING	The purpose of this procedure is to establish a standardized method for determining pH (Acidity or Alkalinity). Testing should be performed at pipe depth anytime the pipeline is exposed. **<u>Determining the pH of Soils And Fluids Using Litmus Paper</u>** Obtain approximately one tablespoon of soil from a site as close as possible to the pipe or structure being tested. Place the soil sample in a clean glass container. Mix the soil thoroughly with an equal quantity of distilled water and allow the mixture to settle for approximately three minutes (or until the water has cleared). Dip a strip of wide range (1-14 pH) litmus paper into the water or fluid according to litmus paper manufacturer's instructions. Compare the color on the test portion of the litmus paper to the color chart on the litmus paper dispenser. Identify the corresponding pH value of the color chart that most closely matches the litmus paper color. If a matching color on the chart cannot be clearly identified, test the sample using litmus paper with a more narrow range Rinse the sample container with distilled water if it is to be used for an additional test. **<u>Determining the pH of Soils Using an Antimony Reference Electrode</u>** Use a voltmeter, a properly maintained Cu/CuSo4 reference electrode and an antimony reference electrode. Connect the Cu/CuSo4 reference electrode to the positive terminal and the antimony cell to the negative terminal of the voltmeter. Buff the antimony cell end that is to be placed in the ground with fine emery cloth. Place the Cu/CuSo4 reference electrode and the antimony cell very close together (within one inch) in the soil to be tested. Select the proper voltage range by switching between the voltage ranges and read the stabilized voltage, usually millivolts, within 30 seconds (highly acidic soil will require more time to stabilize).

PH TESTING CONTINUED	Exchange position of the two cells and repeat steps 2, 3 and 4 of this procedure. Record the average of the two voltage readings, if they differ. Compare the millivolt reading from the voltmeter to the engraved scale on the antimony reference electrode to obtain the pH value **Definitions** Antimony Reference Electrode - An accessory that can measure the pH (acidity) of soil or water Litmus Paper - Is the oldest and most-used indicator of whether a substance is an acid or a base. It turns red or pink in acid solutions and blue or purple-blue in alkaline solutions. pH – Measure of acidity and alkalinity of a solution that is a number on a scale on which a value of 7 represents neutrality and lower numbers indicate increasing acidity and higher numbers increasing alkalinity and on which each unit of change represents a tenfold change in acidity or alkalinity and that is the negative logarithm of the effective hydrogen-ion concentration or hydrogen-ion activity in gram equivalents per liter of the solution.
STRESS CORROSION CRACKING	If the location is within 20 miles (downstream) of a compressor or pump station (currently or previously operating facility) and the section was buried and the coating has been judged to be in either fair or poor condition, then the pipe shall be examined for Stress Corrosion Cracking using Magnetic Particle Inspection, per IM-008 Stress Corrosion Cracking Susceptibility. The presence of SCC should also be investigated in pipeline segments that previously have not been determined to not be susceptible to the SCC threat. All SCC inspections should be documented on Form 124.
RECORDS	The following record must be kept on file for the life of facility for this procedure: ◆ Completed Form 124
REVISION CONTROL	See table below

DATE	DESCRIPTION OF CHANGES
6-5-07	Draft issued for comment