Panhandle Energy

Panhandle Eastern Pipe Line
Trunkline Gas
Trunkline LNG
Sea Robin Pipeline
Florida Gas Transmission

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P.O. Box 4967
Houston, TX 77210-4967
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January 21, 2011

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David Barrett
Director, Central Region
Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
901 Locust Street, Suite 462
Kansas City, Missouri 64106-2641

Certified Mail – Return Receipt Requested
RE: CPF 3-2010-1006M (December 21, 2010 PHMSA Letter)
Response to Notice of Amendment

Dear Mr. Barrett:

In correspondence dated December 21, 2010 and received in our office on December 28, 2010 PHMSA alleges that Panhandle Energy ("PE") had deficiencies in certain procedures that comprise its Standard Operating Procedures ("SOP") in the form of a Notice of Amendment ("NOA"). As noted by PHMSA, these allegations stem from an inspection of PE's Procedures for operations and maintenance activities in our Houston, TX office on the dates of May 17-21, 2010.

PE contests the alleged deficiencies defined for Item #12, Item #15, Item #19 and Item #20, requests that PHMSA reconsider after review of the additional information as detailed herein and requests PHMSA to rescind these allegations and terminate this proceeding relative to those items. PE has initiated enhancements to resolve Item #1 through #11, Item # 13, Item # 14, Item 16, Item # 17 and Item #18 in the NOA. PE is providing a preliminary response to several of the items at this time, but plans to provide a complete response, including the amended procedures, within 45 days of PE's receipt of the NOA (February 11, 2011). Amended procedures not acceptable to PHMSA as submitted constitute items that should be added to the Agenda of the requested hearing.

Accordingly, PE requests an in-person hearing on these issues and the proposed amendments. PE reserves its right to be represented by counsel at a hearing and would plan to have a court reporter record the proceedings. Additional details follow.

Item 1 (§192.13 (c) & §192.503 (a) (1) & (2))

PE's procedures were inadequate because they did not define how much new pipe may be installed during a maintenance project before a pre-test is no longer sufficient and a post-construction hydrostatic test becomes necessary.

PE Response to Item #1

PE Procedure I.02 *Replacement of Pipe Section* has been revised to limit pretested subsections to no more than 7 joints of pipe, including fittings. Step 2 of Section 7.1 "Preparation for Replacement" addresses this limitation. Fabricated assemblies, such as meter assemblies, including pipe, fittings, and valves that have been pressure tested off-site are excluded from this limitation.

Item 2 (§192.225 (b))

PE's procedures were inadequate because they did not require that the welding process qualification test records be retained.

PE Response to Item #2

PE is currently in the process of converting several SOP's into Engineering Standards (ES). PE has initiated the change to include the retention of procedure qualification records in Section 4.2 of the fast tracked draft of ES 7.0004 *Qualification of Welding Procedures*. See the attached proposed modification of ES 7.0004.

Item 3 (§192.231)

PE's procedures were inadequate because they did not define what constitutes adverse weather conditions that would require protection to ensure the quality of the welding was not impaired.

PE Response to Item #3

PE is currently in the process of converting several SOP's into ES's. PE has initiated the change to ES 7.0005 *Production Welding Requirements* in order to require that welding operations be protected from adverse weather conditions in Section 4.2 and to define what is considered to be an adverse weather condition in Section 1.0. See the attached proposed modification of ES 7.0005.

Item 4 (§192.241(a) (1) & (2))

PE's procedures were inadequate because they did not require welding inspectors to be qualified to conduct visual inspections.

PE Response to Item #4

PE is currently in the process of converting several SOP's into ES's. PE has initiated the change in Section 4.14 to ES 7.0005 *Production Welding Requirements* to include the qualification requirements for welding inspectors. See the attached proposed modification of ES 7.0005.

Item 5 (§192.241(b) (2))

PE's procedures were inadequate because they did not define what constitutes "limited in number" such that non-destructive testing becomes impractical.

PE Response to Item #5

PE is currently in the process of converting several SOP's into ES's. PE's ES 7.0005 *Production Welding Requirements* requires that all production welds are to be visually inspected by the designated welding inspector and welder. In addition PE requires that all production welds **2"** and larger in diameter be 100% nondestructively tested by means of radiographic inspection. Nondestructive testing of welds may only be waived after consulting with the Houston Technical Staff provided that the weld is smaller than 6 inches in diameter; the weld has been visually inspected by a qualified inspector, and has met the inspection criteria of API 1104. See the attached proposed modification of ES 7.0005

Item 6: (§192.245 (a))

PE's procedures are inadequate because they reference the wrong sections of API 1104 for repairing or removing weld defects.

PE Response to Item #6

The latest drafts of the Welding ES's (*Volume 7*) are being revised so that section titles are referenced rather than section numbers for both API 1104 and ASME Section IX. Annual reviews of the engineering standards will be implemented so that code editions and references are up to date.

Item 7: (§192.605(b) (1) & §192.612 (b))

PE's procedures for assessing the risk of these pipelines were inadequate because they did not contain sufficient criteria and/or weighting guidance to ensure consistent application.

PE Response to Item #7

PE Procedure O.02 *Submerged Pipe Inspection and Survey* will provide guidance in Steps 3 & 4 and the NOTE between step 3 & 4 of Section 7.1 "Inspection Plan". See the attached proposed modification of O.02.

Item #8: (§192.605(b) (1) & §192.612 (c) (2))

PE's procedures were inadequate because they did not delineate the extent of marking required when the operator discovers a pipeline is exposed on the seabed or constitutes a hazard to navigation.

PE Response to Item #8

PE Procedure O.02 *Submerged Pipe Inspection and Survey* will provide guidance in Step 3 of Section 7.5 "Response to Discovery of Shallow Pipe". See the attached proposed modification of O.02.

Item #9 (§192.605(b) (1) & §192.612 (c) (3))
PE's procedures were inadequate because they did not require PE to provide the necessary cover over the pipeline when it discovers that a pipeline is exposed on the seabed or constitutes a hazard to navigation.

PE Response to Item #9

PE Procedure O.02 *Submerged Pipe Inspection and Survey* will provide guidance in Step 5 of Section 7.5 "Response to Discovery of Shallow Pipe". See the attached proposed modification of O.02.

Item #10 (§192.605(b) (1) & §192.625 (b) (1-4))
PE's procedures were inadequate because they did not include provisions for determining which segments of its transmission pipelines and laterals that is partially located in Class 3 and 4 locations must be odorized in accordance with paragraph (a).

PE Response to Item #10

PE Procedure B.12 *Evaluating Class Location Changes* does in fact contain a provision for determining when odorization is required for laterals and pipelines in Step 3 of Section 7.3 "Determine Subsequent Actions".

In order to provide further clarification, PE has initiated a MOC request to add Appendix D to SOP B.12 with the guidance provided from **§192.625 (b).** See the attached proposed modification of B.12.

Item #11 (§192.605(b) (1) & §192.707 (d) (2))
PE's procedures were inadequate because they still allowed marker signs to be labeled with a telephone number for the public to call collect, even though that option is no longer available through the phone service.

PE Response to Item #11

PE has removed the statement regarding Calling Collect from Section 7.1 of SOP I.12 *Pipeline Facilities Identification*. PE has changed Step 4 in Section 7.1 of SOP I.12 to exclusively reference that the appropriate 24 hour toll free number is to be used on pipeline markers. See the attached proposed modification of I.12.

Item #12 (§192.605(b) (1) & §192.727 (d) (1-3))
PE's procedures were inadequate because they did not include a requirement to utilize one of the three acceptable methods to ensure that gas flow will be prevented whenever service to a customer is discontinued.

PE Response to Item #12

PE challenges the allegation that its procedures are inadequate. From 192.727, the three acceptable methods to ensure that gas flow are:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

PE's current SOP G.19 *Measuring Station Operation* addresses station deactivation in Sections 7.2 "Station Deactivation" and 7.2.1 "Eliminating DOT Inspection Requirements/MMS Terminated Meter". Section 7.2, Step 2 requires the closure and locking/sealing of the inlet and outlet valves of the station. This corresponds with §192.727 (d) (1), which is one of the three acceptable methods to prevent gas flow. Section 7.1.1, Step 1 requires blind flanging of the meter. This corresponds with §192.727 (d) (2), which is another of the three acceptable methods to prevent gas flow.
See the attached proposed modification of G.19.

Item #13 (§192.605(b) (1) & §192.727 (g))
PE's procedures were inadequate because they did not require reports to be filed when an underwater pipeline facility crossing a navigable waterway is abandoned.

PE Response to Item #13

PE Procedure I.07 *Abandonment/Deactivation of Pipeline Facilities* addresses the reporting requirements in Step 12 & the accompanying Note of Section 7.4 "Abandoning Pipelines" and Section 7.6 "PHMSA required Reporting to the National Pipeline Mapping System (NPMS)" required for abandoned laterals and pipelines that cross navigable waterways. See the attached modification of I.07.

Item #14 (§192.605(b) (1) & §192.735 (a))
PE's procedures were inadequate because they did not define what constitutes a combustible material or what quantities are considered necessary for everyday use.

PE Response to Item #14

PE has added a definition of Combustibles in Section 6 and provided guidance regarding every day usage in the Note in Section 7.2.3 of SOP K.10 *Hazardous Materials*. See the attached proposed modification of K.10.

Item #15 (§192.605(b) (1) & §192.739 (a))
PE's procedures were inadequate because they did not include fuel gas regulators as subject to the annual inspection and testing requirements.

PE Response to Item #15

PE challenges the allegation that its procedures are inadequate. PE does in fact require annual inspection and testing of fuel gas regulators. In Section 6, "Terms and Definitions" of SOP M.06 *Regulators - Test, Inspection and Maintenance*. Category 1 regulators are defined as all regulators providing pressure reduction at points of delivery, which would include first cut fuel regulators and Category 2 regulators include fuel regulators downstream of the first cut. In Section 4, "Frequency" of SOP M.06 *Regulators - Test, Inspection and Maintenance*, both

Category 1 and Category 2 regulators are to be annually tested, inspected and maintained annually, at intervals not exceeding 15 months, but at least once each calendar year. See attached pages 1 and 2 of SOP M.06 *Regulators - Test, Inspection and Maintenance*.

Item #16 (§192.605(b) (1) & §192.739 (a) (4))

PE's procedures (G.25, M.06, and M.02) were inadequate because they did not include provisions for inspecting the applicable pressure control devices to ensure they are properly protected from dirt, liquids, and other conditions that may prevent proper operation.

PE Response to Item #16

PE has updated Section 7.2 of SOP G.25 *Farm Tap Settings Inspection and Testing* to include the requirement to inspect equipment for leakage, proper installation, good mechanical condition and protection from dirt, liquid, and physical damage. See attached page 3 from SOP G.25.

PE has initiated a MOC request for Section 7.3 of SOP M.06 *Regulators - Test, Inspection and Maintenance* which includes a requirement to inspect equipment for leakage, proper installation, good mechanical condition and protection from dirt, liquid, and physical damage. See attached page 4 from SOP M.06.

PE has initiated a MOC request for Section 7.1 of SOP M.02 *Automatic Control Valves* which includes a requirement to inspect equipment for leakage, proper installation, good mechanical condition and protection from dirt, liquid, and physical damage. See attached page 4 from SOP M.02.

Item #17 (§192.605(b) (1) & §192.751 (a))

PE's procedures were inadequate because they did not clearly require the removal of potential ignition sources, such as cell phones, in areas where a hazardous amount of gas was being vented into open air.

PE Response to Item #17

PE requires Work Permits for all activities where a hazardous amount of gas may be vented into open air, unless the person performing the activity is equipped with a natural gas monitor. PE initiated a change to the Work Permit noting that cell phones and other electronic devices are not allowed in such areas. Attached is a copy of the revised Work Permit.

Item #18 (§192.605(b) (2) & §192.453)

PE's procedures were inadequate because they did not contain provisions that require the corrosion control program to be carried out by or under the direction of a qualified individual.

PE Response to Item #18

The Volume Owner of Volume D (Corrosion) of the PE Standard Operating Procedures (SOP's) shall be the company corrosion engineer. The volume owner is responsible for guiding the development and updating of all corrosion control procedures. New PE Procedure D.01 will detail the qualifications of this individual.

Item #19 (§192.605(b) (2) & §192.463 (a))

PE's procedures are inadequate because they do not properly consider voltage drops other than those across the structure-electrolyte boundary as required when interpreting the criteria contained in Appendix D. When PE obtains readings that demonstrate inadequate cathodic protection when such voltage drops are eliminated (i.e. instant-off cathodic protection data), PE's procedures do not require PE to verify a different criterion has been met or to remediate the deficiency in its program for controlling corrosion.

PE Response to Item #19

PE believes that their procedures are sufficient for the following reasons.

1. PE SOP D.03, *Structure to Electrolyte Potential Measurement*, requires consideration of voltage drops other than those across the structure-electrolyte boundary for valid interpretation of all readings required by §192.465 (a) in accordance with Appendix D, Part I of §192 and SOP D.20, *Annual Corrosion Control Surveys*.
2. PE SOP D.22, *Application of Cathodic Protection Criteria*, requires consideration of the significance of IR drops other than those across the structure-to-electrolyte boundary and adjustment of structure-to-electrolyte potentials to account for significant voltage drops (other than voltage drops across the structure-to-electrolyte boundary).
3. SOP D.22 requires the adjustment of structure-to-electrolyte potentials where significant voltage drops (other than voltage drops across the structure-to-electrolyte boundary) before determining whether CP is achieved using the 850 mV criterion and remedial action if acceptable levels of cathodic protection cannot be demonstrated.
4. PE's procedures for consideration of voltage drops in SOP D.22 are nearly identical to the guidance provided by NACE International TM0497, *Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems*, for the negative 850 mV current applied criterion for cathodic protection.
5. PE believes that the guidance provided by NACE International and incorporated into SOP D.22 far exceeds PHMSA's interpretation of the regulatory requirements of Appendix D, Part II of §192 provided by the Associate Administrator for Pipeline Safety, George W. Tenley, Jr., in 1991.

> *OPS has been following an enforcement policy developed in the mid 1980's under which, when an operator claims he has accounted for the IR drop, OPS will accept that claim. If, however, the operator had a leak due to corrosion, OPS may ask the operator to demonstrate the adequacy of corrosion protection and hoe (sic) the operator considered the IR drop in determining the adequacy of the corrosion protection. If this was done improperly, the operator could be subject to enforcement action. It has never been OPS's position that the occurrence of a corrosion leak is sufficient evidence of a violation and the operator is to be cited."*

6. The Associate Administrator's interpretation of Appendix D, Part II of §192 has not been revoked by a subsequent interpretation or modification to §192. As such, PE believes that our procedures are adequate and that no changes are required to meet both the letter and intent of §192.605(b) (2) and §192.463.

Item #20 (§192.605(b) (8))

PE's procedures were inadequate because they did not contain detailed provisions for periodically reviewing the work done by employees to determine the effectiveness and adequacy of its procedures.

PE Response to Item #20

PE does not challenge the need for a procedure, but does challenge the need for detailed procedures in its SOP's. PE has an internal process for evaluating the effectiveness of employees and procedures, which is conducted under the direction of and at the request of counsel for PE. This process is not an operations and maintenance function. PE feels that this process not in the Operations and Maintenance organizational structure gives a more unbiased evaluation of procedures. PE has initiated a change to SOP A.03 *Management of Change* to show that changes identified in this process initiates a Procedure change via the MOC process. PE feels that this methodology exceeds the Regulatory burden of **§192.605(b) (8).**

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

PE Request for Hearing

As noted above, solely with regard to NOA Item #12, Item #15, Item #19, and Item #20 PE contests allegations of deficiency and accordingly requests a Hearing as stipulated in 49 C.F.R §190.211 addressing all matters presented in the PHMSA December 21, 2010 letter referenced above. In addition, Amended procedures not acceptable to PHMSA as submitted, constitute items that should be added to the Agenda of the requested hearing. PE feels that existing procedures are adequate regarding Item #12 and Item #15 and requests clarification as to why PHMSA feels that they are inadequate. PE additionally requests an opportunity to provide clarification as to the specific areas of concern regarding Items #19, and Item #20. The principal issues to be raised at hearing are discussed above. PE reserves the right to be represented by counsel during the hearing and plans to have a court reporter present to document the proceedings.

Sincerely,

Eric Amundsen
Vice President and Chief Asset Integrity Officer

Attachment:
August 21, 2010 PHMSA Letter (CPF 3-2010-1006M)
Revised Procedures

Item 1

Code Reference :		Procedure No.: L.02
49 CFR 192.150, 192.485, 192.483, 192.605, 192.703, 192.709, 192.711, 192.713, 192.715, 192.717	Effective Date: *January 7, 2011*	Page 2 of 13

Terms	Definitions
Non-injurious damage condition	A condition that does not impair the safety and serviceability of a pipeline and therefore is not required to be repaired. Any action taken to minimize the effects of the condition or to prevent it from becoming injurious is considered preventive maintenance.
Pressurized repair	A repair that is carried out while the pressure in the pipeline is higher than the atmospheric pressure.
Dutchman	A thin ring cut from a pipeline, usually 2 to 3 inches long, that is taken out to make the removal of a larger piece of pipe easier. (Otherwise, a larger piece of pipe can become cocked and get stuck in place, making it difficult to remove.)

7.0 Replacement of Pipe Section

This section describes the following procedures:

- Preparation for Replacement
- Records

7.1 Preparation for Replacement

A member of the Asset Management Team or Work Crew follows this procedure, with the consultation of the Division Pipeline Specialist, before a section of pipe is replaced.

NOTE: Refer to *SOP L.01 Pipeline Shutdown and Startup* in conjunction with this SOP for development of a shutdown plan and other shutdown actions.

Step	Activity
1	**VERIFY** the class location, Maximum Allowable Operating Pressure (MAOP), and design criteria of the replacement pipe meet or exceed the design. Also, replacement pipe **MUST** be coated and cathodically protected.
2	**VERIFY** that pretested subsections do not exceed 7 joints of pipe in length, including fittings. Fabricated assemblies consisting of pipe, fittings, and valves that have been pressure tested off-site are excluded.
3	**VERIFY** that the welders are qualified in accordance with the company *Welding Manual* and Operator Qualification requirements.
4	**VERIFY** that qualified welding procedures are available on site.
5	**CONDUCT** a pre-job safety meeting to discuss the sequence of events for the work.
6	**SHUT OFF** the electrical power to nearby cathodic protection units for extended pipeline shutdowns.
7	**SHUT DOWN** pipeline per *SOP L.01*.
8	**VERIFY** that the correct pipeline is blown down before performing any work. **REFER** to alignment sheets, maps, or drawings.
9	**TEST** the work area to verify it is free of flammable vapors before the pipeline is cut to make the repair.

Item 2

NOA Item #2

4.1 Codes and Standards

The following requirements apply to the codes and standards used to qualify welding procedures:

1. All welding procedures used for structural steels must be in accordance with *AWS D1.1, Structural Welding Code—Steel.* These procedures may be pre-qualified procedures; if they are, they must be designated as such.
2. All other welding procedures must be in accordance with *API 1104, Welding of Pipelines and Related Facilities*, unless the welding situation dictates the use of the section of the *ASME Boiler and Pressure Vessel Code (BPVC)* on *Welding and Brazing Qualifications*. *API 1104* is the default code for welding procedure specifications; if Houston QA/QC determines that the *ASME BPVC* section on *Welding and Brazing Qualifications* is applicable, Houston Technical Services must give approval prior to procedure qualification.
3. This ES does not, in any instance, reduce the requirements of *API 1104*.

4.2 General Requirements

The following general requirements apply to the qualification of welding procedures:

1. A Welding Procedure Specification (WPS) must be qualified by destructive testing, and the company representative/welding inspector administering the test must record the results in a Procedure Qualification Record (PQR).
2. The company representative must submit all completed WPSs and PQRs to Houston QA/QC.
3. All welding procedures must be approved by Houston QA/QC prior to distribution and use.
4. All WPSs, WPS revisions, and corresponding PQRs must be retained for the life of the facility by Houston QA/QC.

> NOTE: A selection of previously qualified and approved WPSs is provided in *ES 7.0011 Welding Procedure Specifications*. For specialized welding procedures or outside company procedures that are not included in *ES 7.0011*, please contact Houston QA/QC.

5. Each procedure must specify each essential, supplementary essential, and, when required, nonessential variable. Refer to *Section 4.3 Essential and Nonessential Variables* of this ES for an explanation of variables.
6. A WPS may be supported by one or more PQRs.

4.3 Essential and Nonessential Variables

Essential variables can be found in the section of *API 1104* on *Qualification of Welding Procedures for Welds Containing Filler-metal Additives*. These lists and tables must be consulted when writing, auditing, or changing a WPS. Understanding these variables is crucial to verifying that a procedure is written correctly within the confines of the code. Changing an essential variable requires a requalification of the WPS.

There are nonessential variables that must be specified and included in each WPS, but

<u>Item 3</u>

NOA Item #3

Panhandle Energy

Engineering Standards
Volume 7 - WELDING

Production Welding Requirements

Code Reference:	Document No.: 7.0005	
	Effective Date: *Draft 2*	Page 1 of 22

1.0 Standard Description

The Production Welding Requirements Engineering Standard (ES) establishes the specific company requirements for production welding utilizing qualified Welding Procedure Specifications (WPS) and qualified welders.

2.0 Scope

This ES covers the requirements for welding on company pipelines and associated components.

3.0 Terms and Definitions

Terms and definitions associated with this ES follow in the table below.

Terms	Definitions
Adverse Weather Conditions	Weather conditions that could negatively impact the integrity of a weld (e.g., severe wind, precipitation, or very low temperatures).
API 1104	American Petroleum Institute Standard 1104, Twentieth Edition, 2007/2008 Errata/Addendum, *Welding of Pipelines and Related Facilities*
Arc Length	The distance between the tip of the welding electrode and the adjacent surface of the weld pool. Long arc lengths can result in weld spatter or porosity in the weld. Short arc lengths can result in tall, narrow beads.
ASME Section IX	ASME Section IX—*Welding and Brazing*, 2010
Backhand	When the welding torch or gun is directed opposite the direction of welding.
Backweld	A weld installed on the inside surface of a pipe joint (generally a butt weld configuration) at any time after the first stringer bead has been installed from the outside of the pipe.
Backing Weld	A weld installed on the inside surface of a pipe joint (generally a butt weld configuration) as the first stringer bead, before any weld is made from the outside of the pipe.
Carbon Equivalent	A quantitative measure of the weldability of a metal, based on hardenability, determined by the metal's chemical composition according to the following: CE_{IIW} = %C + %Mn/6 + %(Cr+Mo+V)/5 + %(Cu+Ni)/15
Contract Welder	A welder employed by a third party that has been retained by the company to weld on pipelines and related facilities.

- Welding Inspectors
- Nondestructive Testing
- Waiver of Nondestructive Testing
- Arc Burns
- Cracks
- Repair of Production Welds
- Repair of Welds in Existing Pipelines
- Nondestructive Testing of Repair Welds
- Pipe Repairs
- Weld Identification

4.1 General Requirements

Production welding must be:

1. Conducted in accordance with *API 1104*.
2. Conducted with an approved WPS.
3. Performed by a qualified welder.
4. Protected from adverse weather conditions that would impair the required quality of the completed weld.

4.2 Alignment and Fit-up

The following requirements apply to alignment and fit-up of production welds:

1. The WPS must designate whether the line-up clamp is to be internal or external, or if no clamp is required. If a clamp is required, the minimum percentage of root bead welding that must be completed before the clamp is released must be specified.
2. All practical alignment and fit-up efforts must be made to produce welds that are free of external stresses. If a weld must be completed in a high stress state, approval must be obtained from the QAQC in Houston.
3. For line pipe welding, line-up clamps must be used to prevent root bead cracking and provide proper alignment of the materials for welding of the root bead.

4.2.1 Offset and Spacing

The following requirements apply to offset and spacing of production welds:

1. Any offset between joints must be evenly distributed around the joint.
2. A Deerman style lineup clamp may be used in a situation where misalignment is an issue. This style of external lineup clamp may help to distribute misalignment

Item 4

NOA Item #4

Code Reference :	Document No.: 7.0005	
	Effective Date: Draft 2	Page 15 of 22

4.12 Cleaning Between Weld Passes

The following requirements apply to cleaning between weld passes:

1. Cleaning must be conducted in accordance with the WPS.
2. Cleaning must be conducted so that the joint bevel and the weld faces are shiny metallic, and free of slag and other foreign material.
3. Cleaning between the root bead and the hot pass must make the transition between the joint bevels and the weld face smooth, and no deep recesses may exist.
4. At a minimum the weld must be wire brushed between all weld passes.

4.13 Visual Inspection of the Weld

The following requirements apply to visual inspection of the weld:

1. The welder and designated welding inspector must perform a visual inspection of each production weld to confirm that it is in compliance with the welding procedure being used.
2. The production weld must meet the requirements for visual inspection according to *API 1104*. The weld must
   a. Be free from:
      i. Cracks.
      ii. Inadequate penetration.
      iii. Burnthrough.
      iv. Other defects.
   b. Exhibit a neat, workmanlike appearance.
3. Visual inspection must be completed prior to nondestructive testing.

4.14 Welding Inspectors

Personnel who perform visual inspections and recordings of welding and fabrication activities must be approved by the Senior Welding Inspector or Chief Inspector prior to surveillance of welding-related activities. These personnel must meet the following requirements:

1. They must hold one or more of the following certifications:
   a. Current or previous AWS senior certified welding inspector
   b. Current or previous AWS certified welding inspector
   c. Current or previous AWS certified associate welding inspector
   d. Welding inspector certified by the contractor's documented training program (as accepted by Florida Gas Transmission [FGT])
2. They must posses the following measuring devices and instruments to perform welding inspections:

a. An amperage meter (analog or digital)

b. A voltmeter

c. A 6-inch dial or digital caliper

d. A pit measurement gauge

e. A tempil-stiks or non-contact infrared thermometer

f. A measuring tape

g. A 6-inch scale in 64th and 32nd

h. A diameter tape or pi tape

i. A calculator

3. They must have a copy of all company welding ESs and the NDE manual with them at all times.

4. They must verify, daily, that their measuring devices and instruments are properly functional.

5. They must be familiar with all applicable codes.

4.15 Nondestructive Testing

Except as noted in section *4.16 Waiver of Nondestructive Testing* of this ES, all production welds 2 inches and larger must be 100 percent nondestructively tested in accordance with *ES 7.0014 Radiography* and must meet the standards for nondestructive testing according to *API 1104*.

The Division Technical Staff must approve contractors who perform radiographic inspection.

4.16 Waiver of Nondestructive Testing

After consulting the Houston Technical Staff, the Division Technical Operations Superintendent may waive the nondestructive testing of welds if:

1. The welds are smaller than 6 inches.

2. A qualified inspector, as designated by the Senior Welding Inspector or Chief Inspector:

   a. Visually inspects the welding.

   b. Watches for proper grinding and cleaning between passes.

   c. Inspects the completed welds.

3. The inspector has sufficient training and experience to confirm that the weld meets the visual inspection criteria of *API 1104*.

4. The weld meets the inspection criteria of API 1104 and has been found acceptable.

Item 5

4.12 Cleaning Between Weld Passes

The following requirements apply to cleaning between weld passes:

1. Cleaning must be conducted in accordance with the WPS.
2. Cleaning must be conducted so that the joint bevel and the weld faces are shiny metallic, and free of slag and other foreign material.
3. Cleaning between the root bead and the hot pass must make the transition between the joint bevels and the weld face smooth, and no deep recesses may exist.
4. At a minimum the weld must be wire brushed between all weld passes.

4.13 Visual Inspection of the Weld

The following requirements apply to visual inspection of the weld:

1. The welder and designated welding inspector must perform a visual inspection of each production weld to confirm that it is in compliance with the welding procedure being used.
2. The production weld must meet the requirements for visual inspection according to *API 1104*. The weld must
   a. Be free from:
      i. Cracks.
      ii. Inadequate penetration.
      iii. Burnthrough.
      iv. Other defects.
   b. Exhibit a neat, workmanlike appearance.
3. Visual inspection must be completed prior to nondestructive testing.

4.14 Welding Inspectors

Personnel who perform visual inspections and recordings of welding and fabrication activities must be approved by the Senior Welding Inspector or Chief Inspector prior to surveillance of welding-related activities. These personnel must meet the following requirements:

1. They must hold one or more of the following certifications:
   a. Current or previous AWS senior certified welding inspector
   b. Current or previous AWS certified welding inspector
   c. Current or previous AWS certified associate welding inspector
   d. Welding inspector certified by the contractor's documented training program (as accepted by Florida Gas Transmission [FGT])
2. They must posses the following measuring devices and instruments to perform welding inspections:

a. An amperage meter (analog or digital)

b. A voltmeter

c. A 6-inch dial or digital caliper

d. A pit measurement gauge

e. A tempil-stiks or non-contact infrared thermometer

f. A measuring tape

g. A 6-inch scale in 64th and 32nd

h. A diameter tape or pi tape

i. A calculator

3. They must have a copy of all company welding ESs and the NDE manual with them at all times.

4. They must verify, daily, that their measuring devices and instruments are properly functional.

5. They must be familiar with all applicable codes.

4.15 Nondestructive Testing

Except as noted in section *4.16 Waiver of Nondestructive Testing* of this ES, all production welds 2 inches and larger must be 100 percent nondestructively tested in accordance with *ES 7.0014 Radiography* and must meet the standards for nondestructive testing according to *API 1104*.

The Division Technical Staff must approve contractors who perform radiographic inspection.

4.16 Waiver of Nondestructive Testing

After consulting the Houston Technical Staff, the Division Technical Operations Superintendent may waive the nondestructive testing of welds if:

1. The welds are smaller than 6 inches.
2. A qualified inspector, as designated by the Senior Welding Inspector or Chief Inspector:
   a. Visually inspects the welding.
   b. Watches for proper grinding and cleaning between passes.
   c. Inspects the completed welds.
3. The inspector has sufficient training and experience to confirm that the weld meets the visual inspection criteria of *API 1104*.
4. The weld meets the inspection criteria of API 1104 and has been found acceptable

Item 7

7.1 Inspection Plan

The process below describes how to develop the inspection plan for submerged pipe.

Step	Task	Done By
1	Identifies and inspects each company pipeline segment in the Gulf of Mexico and its inlets that are in water less than 15 feet deep, as measured from mean low water, **AND AT RISK OF BEING AN EXPOSED UNDERWATER PIPELINE OR A HAZARD TO NAVIGATION.**	Division Pipeline Specialist

Comment [c1]: BOLD & Capitalized to bring attention. Critical statement for future planning.

NOTE: Affected underwater pipeline segments and inspection schedules can be found in EAM.

Step	Task	Done By
2	Develops and maintains an inspection plan that is prioritized by the calculated risk for each underwater pipe segment based on specific identified threats for each individual pipeline segment.	Division Pipeline Specialist
3	Calculates the risk from a value assigned to specific threats listed below: • Year of Installation • Last known depth of cover • Proximity to marked channels, fairways or anchorage areas • Level of commercial fishing activity • Level of construction, drilling or production activity • Number of appurtenances such as: future side taps, subsea tie-ins, inline valves, etc. • Concrete coating (Yes/No) • Soil condition (Stable/Unstable) • Scour potential • Hurricane or Tropical Storm History in the vicinity, since the last Inspection	Division Pipeline Specialist

Continued on next page

Code Reference:		Procedure No.: O.02
49 CFR 192.612 & 33 CFR part 64	Effective Date: *January 14, 2008*	Page 4 of 9

NOTE:

1. ~~The 1992 Terrebonne, Vermilion and Sea Robin System Depth of Cover Surveys and the 1999 Galveston Bay Depth of Cover Survey will be used as baseline data.~~
2. Various types of data, including but not limited to, GIS data, historical data, data documented from previous projects, local knowledge, will be used to determine risk associated with the various pipeline segments.
3. All soils along the offshore pipelines systems are known to be stable BASED ON NOAA SURVEY DOCUMENTATION.
4. The Risk Calculation Spreadsheet will reside attached to the PM Job in EAM.
5. ~~The initial inspection plan will be based on a three year program (2006-2008). This accelerated schedule will be used to verify baseline data and allow the establishment of more realistic inspection frequencies for each line segment, based on calculated risk. After each segment is inspected, the data will be analyzed and the inspection frequency re-established and entered into the EAM System.~~

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Comment [c4]: DELETE

Step	Task	Done By
4	Conducts the initial inspections, within the three-year program deadline. ACCORDING SUBMERGED PIPELINE INSPECTION PLAN.	Asset Management Team is responsible for budgeting, bidding, and scheduling.
5	Enters the completion date in EAM	Asset Management Team
6	Forwards data to the Division Pipeline Specialist for analysis.	Asset Management Team
7	Provides the scope of work.	Division Pipeline Specialist
8	Analyzes the inspection data.	Division Pipeline Specialist
9	Establishes new inspection frequency.	Division Pipeline Specialist

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Comment [c6]: DELETE

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7.2 Reporting Requirements for Inspection Plans

The process below describes reporting requirements for inspection plans.

Step	Task	Done By
1	Documents the analysis and decision process.	Division Pipeline Specialist
2	Submits an Offshore Condition Report to the Department of Transportation (PHMSA) within 60 days of completion of all of the underwater pipelines included in the inspection plan.	Division Pipeline Specialist

Continued on next page

Item 8

Step	Task	Done By
3	Based on the scope of work, performs the recommended depth of cover inspection of underwater pipelines and facilities. Forwards data to the Division Pipeline Specialist for analysis.	Area Management/Asset Management Team
4	Conducts subsequent inspections based upon the new inspection frequency. Enters the completion date in EAM and forwards data to the Division ~~Technical Staff~~ Pipeline Specialist for analysis.	Area Management/Asset Management Team is responsible for budgeting, bidding, and scheduling.
5	Documents the analysis and the decision process.	Division Pipeline Specialist

7.4 Typical Storm Evaluation Criteria

The Division Pipeline Specialist uses these criteria for post storm inspections as measured from the path of the storm.

Criteria	Inspection
20-30 miles	Inspect subsea tie-ins, future taps, line crossings, and locations known to have greater than 12 inches but less than 36 inches of cover.
10-19 miles	Inspect all items in the 20-30 mile inspection and include beach approaches to a point one mile out or to waters less than 15 feet deep, as measured from the low mean water.
< 10 miles	Perform a depth of cover inspection on all underwater pipelines and facilities to a point out three miles or to waters less than 15 feet deep, as measured from mean low water.

NOTE: The Division Pipeline Specialist may perform the inspection whether or not any offshore regulatory agency issues additional specific inspection requirements. The DPS may perform the inspection in conjunction with those additional inspection requirements.

7.5 Response to Discovery of Shallow Pipe

The Asset Management Team or work crew follows the steps below in response to the discovery of exposed pipe or pipe determined to Hazard to Navigation in the Gulf of Mexico and its inlets in waters less than 15 feet deep.

Step	Task	Done By
1	Immediately upon report of discovery **CONTACT** the Division Pipeline Specialist and supply the following information: 6. Company line number and BOEMRE Pipeline Segment Number. 7. BOEMRE or State assigned Area and Block Number. 8. Latitude and longitude of the beginning and end of exposed pipeline facility or area of less than 12 in. of cover. 9. Approximate footage of pipe exposed or with less than 12 in. cover. 10. Water depth.	Asset Management Team or work crew
2	Promptly, but not later than 24 hours after discovery **CONTACT** the National Response Center at **800.424.8802.**	Division Pipeline Specialist
3	Promptly, but not less than 7 days after discovery, **MARK** the location of the pipeline with a lighted buoy, with alternating orange and white stripes (per 33 CFR 64), at the ends of the pipeline segment and at intervals not over 500 yards long, except that a pipeline segment less than 200 yards long need only be marked in the center. **CONSULT** Division Pipeline Specialist to determine proper marking requirements.	Asset Management Team or work crew
4	**INFORM the** Division Integrity Engineer of the available information concerning the discovery of exposed submerged pipe or a potential Hazard to Navigation.	Division Pipeline Specialist
5	Within 6 months after discovery, or not later than November 1st of the following year if the 6 month period later the November 1st of the year of discovery, **BURY** the pipeline so that the top of the pipe is 36 inches below the underwater natural bottom for normal excavation or 18 inches for rock excavation. Engineered alternatives, such as, articulating mats, may be used so long as they meet or exceed the level of protection provided by burial. **CONSULT** Division Pipeline Specialist to determine proper engineered alternative to be used.	Asset Management Team or work crew
6	**SUBMIT** permit applications to the proper state	Division Pipeline Specialist

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Step	Task	Done By
1	Immediately upon report of discovery **CONTACT** the Division Pipeline Specialist and supply the following information: 6. Company line number and BOEMRE Pipeline Segment Number. 7. BOEMRE or State assigned Area and Block Number. 8. Latitude and longitude of the beginning and end of exposed pipeline facility or area of less than 12 in. of cover. 9. Approximate footage of pipe exposed or with less than 12 in. cover. 10. Water depth.	Asset Management Team or work crew
2	Promptly, but not later than 24 hours after discovery **CONTACT** the National Response Center at **800.424.8802.**	Division Pipeline Specialist
3	Promptly, but not less than 7 days after discovery, **MARK** the location of the pipeline with a lighted buoy, with alternating orange and white stripes (per 33 CFR 64), at the ends of the pipeline segment and at intervals not over 500 yards long, except that a pipeline segment less than 200 yards long need only be marked in the center. **CONSULT** Division Pipeline Specialist to determine proper marking requirements.	Asset Management Team or work crew
4	**INFORM the** Division Integrity Engineer of the available information concerning the discovery of exposed submerged pipe or a potential Hazard to Navigation.	Division Pipeline Specialist
5	Within 6 months after discovery, or not later than November 1st of the following year if the 6 month period later the November 1st of the year of discovery, **BURY** the pipeline so that the top of the pipe is 36 inches below the underwater natural bottom for normal excavation or 18 inches for rock excavation. Engineered alternatives, such as, articulating mats, may be used so long as they meet or exceed the level of protection provided by burial. **CONSULT** Division Pipeline Specialist to determine proper engineered alternative to be used.	Asset Management Team or work crew
6	**SUBMIT** permit applications to the proper state	Division Pipeline Specialist

	and Federal agencies. **CONSULT** Division Environmental Specialist regarding required permit requirements.	
7	If the required state or Federal permits cannot be obtained in time to comply with this Step #4; **NOTIFY** the DOT Office of Pipeline Safety; specify whether the permit is state or Federal; and justify the delay.	Division Pipeline Specialist and Codes
8	**PROVIDE** a minimum of three copies of the pipeline cover repair as built drawings. **FORWARD** copies to: 1. Area Compliance File 2. Division Pipeline Specialist 3. Division Integrity Engineer	Asset Management Team or work crew

8.0 Documentation Requirements

Offshore Condition Report

Activity	TGC & SR
Acknowledge the requirements as outlined in the SOP have been completed. Record exemptions, if any, in the comments section.	EAM
Initial Inspection Date	EAM
Next Scheduled Inspection Date	EAM
Completion Date	EAM

9.0 References

There are no references in this SOP.

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NOTE: Subsequent actions include requesting additional information or field verification of data used in class location boundary determination, assessment of need for additional valves, determination of requirements for odorization, and confirmation or revision of MAOP.

Step	Task	Done By
2	**USE** 192.179 and industry and PHMSA guidance to assess need for additional valves, 192.625 to determine whether additional odorization is required, and *SOP B.10 Determination of MAOP* to evaluate any impact on MAOP. Appendix D provides odorization guidance.	Codes Engineer

NOTE: Such options generally include reduction of MAOP, hydrostatic testing or replacing pipe to maintain MAOP, applying for a waiver to maintain MAOP, or purchasing one or more structures to eliminate the class location change.

3	**COMMUNICATE** any such impacts as appropriate to Engineering and Construction and Operations, with an explanation of the requirements and the options available to them.	Codes Engineer
4	**PERFORM** an O&M review of the proposed class change locations. **CHANGE** schedule of O&M required tasks based upon the new Class Location.	Asset Management Team or Work Crew
5	**ADVISE** operating personnel of affected segments with changes in class location, or class location boundaries where no facility changes are required.	Asset Management Team or Work Crew

7.4 Apply Class Location Logic

The GIS Analyst executes the ClassWorks program.

Step	Activity
1	**EXECUTE** the ClassWorks program.
2	**VERIFY** that the table has been properly populated.
3	**NOTIFY** process owners that ClassWorks has been run and the results are ready for their review and subsequent action.

Appendix D: Class Location required Odorization requirements

The requirements regarding odorization installation for laterals and pipelines with Class 3 or 4 piping.

A combustible gas in a transmission line in a Class 3 or Class 4 location must be odorized unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

Item 11

- Painted Fence Posts
- Facility Signs
- Maintenance

7.1 Placement of Pipeline Markers

The Asset Management Team or Work Crew member follows the steps below for the placement of pipeline markers at the following locations:

- Stream crossings
- Both sides of public road crossings
- Other utility's ROW
- Both sides of railroad crossings
- Aboveground pipelines in areas accessible to the public
- Any other location where it is necessary to identify the pipeline location

Step	Activity
1	**PROVIDE** pipeline identification and warning information on casing vents or pipeline markers.
2	**PLACE** markers at line-of-sight intervals where practical and in all Class 3 areas.
3	**REFER** to the appropriate company standard drawings for installation details.
4	**VERIFY** that all pipeline identification markers have the appropriate, 24-hour, toll-free, emergency phone number.
5	**PLACE** a marker decal with the correct phone number on any signs not bearing the correct number.

NOTE: Do not place markers for offshore buried lines or crossings of other large bodies of water, except at the water's edge.

7.2 Aerial Markers

The Asset Management Team or Work Crew member follows the steps below for installing aerial markers.

NOTE: Aerial markers include mileposts, valve numbers, and other pipeline information visible by aerial patrol.

Step	Activity
1	**INSTALL** aerial patrol markers at frequent intervals and at all industrial sites only where necessary to assist the aerial patrol pilot in identifying locations along the pipeline ROW.
2	**VERIFY** that aerial patrol markers are maintained in good condition and are clearly visible from the air.

Continued on next page

Item 12

Regulators—Test, Inspection, and Maintenance

Code Reference:	Procedure No.: M.06	
49 CFR: 192.739	Effective Date: *January 1, 2007*	Page 1 of 8

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes the requirements for the test, inspection, maintenance and overhaul of category 1, 2, and 3 regulators.

2.0 Scope

This SOP covers requirements for inspection, testing, and overhaul of category 1, 2, and 3 regulators and contributes to compliance with federal regulations.

3.0 Applicability

This SOP provides compliance with federal and company standards.

4.0 Frequency

<u>Category 1 and 2 regulators</u>

Annually: test, inspection and maintenance at intervals not exceeding fifteen (15) months, but at least once per calendar year

<u>Category 1 regulators only</u>

Every five years, not to exceed the fifth calendar year: Perform five-year overhaul

<u>Category 3 regulators</u>

Throughout the year without a specified test and inspection (T&I) timeframe: Observe for proper operation, but repair or replace as needed. No PM job associated or records are maintained.

NOTE:
1. For farm tap setting regulator and relief valve inspection and testing frequency, refer to current PEPL/TGC/SR procedure regarding farm taps.
2. If equipment or physical conditions change between scheduled inspections and tests, perform the appropriate activities required by this procedure as needed to assure continued compliance. Document unplanned work orders in EAM.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Operations	Asset Management Team or Work Crew	Operations Manager	Asset Management Team or Work Crew

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6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *A.01 Glossary and Acronyms*.

Terms	Definitions
Category 1	All Regulators providing pressure reduction at points of deliveries and receipts of the transmission system (PM Job 7T0104 – DOT OQ)
Category 2	Fuel Gas Regulators downstream of the first cut: individual engine fuel, starting gas, emergency fuel, etc. (PM Job 7T0223-SOP)
Category 3	Regulators on catalytic and in-line heaters, instrument gas, and other small regulators
Regulator	A pressure-reducing device that is used to verify that the downstream pressure is maintained with varying inlet pressures and flow rates. Regulators may be spring loaded (self operated), pilot operated, or controller operated
Standby Regulator	A pressure-reducing device installed in parallel with the primary regulator and is set to operate at a set point lower than the primary regulator. The “standby” regulator activates when the primary regulator fails to operate properly or does not have enough capacity. When installed in parallel with a downstream flow control valve(s), the standby device is referred to as a pressure under-ride and maintains a minimum pressure downstream
Transmission System	All deliveries and receipts, including the first cut regulator and relief valves at compressor stations
Worker/Monitor Regulation	Arrangements where two pressure reducing devices are installed in series to accomplish both primary and secondary pressure protection. Set point guidelines for worker/monitor regulation are found in *M.04 Pressure Protection and Relief Valve Capacity Verification*. Monitor regulators are installed either upstream or downstream of worker regulators and activate at a pressure slightly higher than the primary and standby regulators to provide backup pressure control if the worker regulator fails to operate properly

7.0 Regulators – Test, Inspection, and Maintenance

The following procedures are described in this section:

- Prior to Test and Inspection
- Temporary Operations of Standby and Monitor Equipment
- Annual Test, Inspection, and Maintenance
- Five-year Overhaul

Item 13

Step	Activity
12	**COMPLETE** the *Form 7T-71* once the pipeline has been idled, noting that the pipeline is being decommissioned. For abandoned offshore lines and onshore lines that pass over, under or through a commercially navigable waterway **SUBMIT** Special Reporting information with the *Form 7T-71*.

NOTE: For abandoned Offshore Lines and onshore lines that pass over, under or through a commercially navigable waterway a statement that details the following needs to accompany the Retirement Completion Report:

- Line Identification
- Date of Abandonment
- Diameter
- Method of Abandonment
- Statement that Abandonment was completed in accordance with applicable laws to the best of the Company's knowledge

Step	Activity
13	**COMPLETE** the *Form C-757 Work Order* to remove the abandoned pipeline from the Gas Plant accounting classification.
14	**DISCONTINUE** right-of-way maintenance, cathodic protections, patrolling, and other forms of maintenance.

7.5 Permanent Removal of Pipelines

Upon receiving written authorization from Vice President of Technical Services, a member of the Asset Management Team or Work Crew performs the following steps to permanently remove a pipeline.

Step	Activity
1	**CLEAN** and **SHUTDOWN** the pipeline section in accordance with *SOP I.01.*
2	**DISCONNECT** and **ISOLATE** the pipeline by physically separating it from all sources and supplies of gas, such as pipelines, crossover piping, branch connections, or measuring stations.
3	**SEAL** any taps, branch connections, or other sources leading to the isolated facility with a plug, cap, blind, or a permanent type closure or fitting.
4	**REMOVE** the pipeline in accordance with the removal plan.
5	**REMOVE** all aboveground signs and markers.
6	**COMPLETE** the *Form 7T-71* once the pipeline has been idled, noting that the pipeline is being decommissioned.

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Step	Activity
7	**COMPLETE** the *Form C-757* to remove the abandoned pipeline from the Gas Plant accounting classification. **INCLUDE** the following information: • Reason for abandonment or removal • Pipe description: diameter, wall thickness, and grade • Pipe length • Location • Dates • Purging method and media • Methods of isolating gas sources • Inhibitor, if used • Line pressure at completion

NOTE: This work order is the final documentation for an abandonment or permanent removal.

8	**DISCONTINUE** maintenance associated with the right-of-way.

7.6 PHMSA required Reporting to the National Pipeline Mapping System (NPMS)

GIS Management submits NPMS required attributes and information from the Special Reporting to the NPMS for abandoned offshore pipelines and onshore pipelines that cross over, under and through commercially navigable waterways.

GIS Management obtains the required information from the *Form 7T-71* and Special Reporting detailed in this SOP. This Special Report is submitted annually to the NPMS in addition to other required supporting information.

Item 14

Hazardous Materials

Code Reference :	Procedure No.: K.10	
29 CFR 1910.120; 29 CFR 1910.1200; 49 CFR Part 192.735 (a) and (b)	Effective Date: *July 1, 2007*	Page 1 of 11

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes the requirements for the safe handling and storage of hazardous materials.

2.0 Scope

This SOP is used when handling or storing compressed gas cylinders, solvents, paints, and flammables. This procedure also provides guidance to the Hazardous Communication Program and the process for approval of chemicals.

3.0 Applicability

This SOP applies when employees handle or store chemicals.

4.0 Frequency

As required: When working with hazardous materials.
Every 60 months: Document hazardous material training.
Every 60 months: Compressed Gas Cylinders.
Initial Training: Flammable and Combustible Materials.
Every 60 months: Flammable and Combustible Materials.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in Section 7.0 of this SOP.

Function	Responsibility	Accountability	Authority
All Operations	Asset Management Team or Work Crew	Asset Management Team or Work Crew	Operations Manager

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *A.01 Glossary and Acronyms.*

Terms	Definitions
Clean-up Operation	An operation where hazardous substances are removed, contained, incinerated, neutralized, stabilized, cleared-up, or in any other manner processed or handled with the ultimate goal of making the site safer for people or the environment.
Combustible Materials	Combustible materials are those capable of igniting and burning (any substance with a flashpoint of above 100° F for OSHA or 140° F for DOT).

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Deleted: Any liquid having a flashpoint at or above 100 deg. F (37.8 deg. C), but below 200 deg. F (93.3 deg. C).

Deleted: Combustible Solid

Deleted: Materials capable of igniting and burning like wood or paper.

Code Reference :		**Procedure No.: K.10**
29 CFR 1910.120; 29 CFR 1910.1200; 49 CFR Part 192.735 (a) and (b)	**Effective Date:** ***July 1, 2007***	**Page 6 of 11**

7.2.3 Flammable Liquids and Combustible Materials

Flammable liquids include volatile materials such as gasoline, alcohol, turpentine, paint thinner, paints and lacquers, cleaning solutions, and many petroleum products. Particular care must be exercised in handling these materials. Combustible materials are those capable of igniting and burning (any substance with a flashpoint of above 100° F for OSHA or 140° F for DOT).

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Follow these steps when handling flammable liquids.

Step	Activity
1	When transferring flammable liquids from one container to another, **MAINTAIN** a metallic bond or contact between the containers. Immediately **CLEAN UP** any flammable liquid that is spilled.
2	**STORE** flammable liquids in approved, properly labeled containers. **HANDLE** and **DISPENSE** only in appropriate, properly labeled, red safety cans.

NOTE: Refer to CFR 49 Part 192.735 (a) and (b) below:

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building. Everyday use is defined as what is necessary to protect equipment or parts, and allow for safe movement of equipment during maintenance activities (i.e., cardboard under removed engine parts to protect from damage; pallets for forklift usage, etc.). Amounts greater than these should be properly stored.

(b) Above ground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

Storage of flammable and combustible materials shall be orderly. Storage shall be separated from heating devices and sources by distance or shielding so that ignition cannot occur.

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7.2.4 Gasoline Handling and Use

Follow these steps when handling and using gasoline.

Step	Activity
1	**NEVER USE** gasoline for cleaning purposes.
2	**DO NOT TRANSPORT** gasoline in other than approved, safety containers, and **DO NOT HAUL** these containers inside of cars or truck cabs.
3	**DO NOT POUR** or **HANDLE** gasoline around open or unprotected flames, electrical equipment, areas where sparks or static electricity may be present, or in non-ventilated places.
4	**DO NOT STORE** gasoline in open, plastic, or glass containers; in non-ventilated places; near sources of fire; near electrical equipment, or near combustible materials, such as textiles, cardboard boxes, paper, etc.
5	**DO NOT SIPHONE** gasoline by mouth suction from tanks or containers.

Item 15

Regulators—Test, Inspection, and Maintenance

Code Reference:	**Procedure No.: M.06**	
49 CFR: 192.739	**Effective Date:** *January 1, 2007*	**Page 1 of 8**

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes the requirements for the test, inspection, maintenance and overhaul of category 1, 2, and 3 regulators.

2.0 Scope

This SOP covers requirements for inspection, testing, and overhaul of category 1, 2, and 3 regulators and contributes to compliance with federal regulations.

3.0 Applicability

This SOP provides compliance with federal and company standards.

4.0 Frequency

Category 1 and 2 regulators

Annually: test, inspection and maintenance at intervals not exceeding fifteen (15) months, but at least once per calendar year

Category 1 regulators only

Every five years, not to exceed the fifth calendar year: Perform five-year overhaul

Category 3 regulators

Throughout the year without a specified test and inspection (T&I) timeframe: Observe for proper operation, but repair or replace as needed. No PM job associated or records are maintained.

NOTE:

1. For farm tap setting regulator and relief valve inspection and testing frequency, refer to current PEPL/TGC/SR procedure regarding farm taps.
2. If equipment or physical conditions change between scheduled inspections and tests, perform the appropriate activities required by this procedure as needed to assure continued compliance. Document unplanned work orders in EAM.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Operations	Asset Management Team or Work Crew	Operations Manager	Asset Management Team or Work Crew

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6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *A.01 Glossary and Acronyms*.

Terms	Definitions
Category 1	All Regulators providing pressure reduction at points of deliveries and receipts of the transmission system (PM Job 7T0104 – DOT OQ)
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Category 3	Regulators on catalytic and in-line heaters, instrument gas, and other small regulators
Regulator	A pressure-reducing device that is used to verify that the downstream pressure is maintained with varying inlet pressures and flow rates. Regulators may be spring loaded (self operated), pilot operated, or controller operated
Standby Regulator	A pressure-reducing device installed in parallel with the primary regulator and is set to operate at a set point lower than the primary regulator. The "standby" regulator activates when the primary regulator fails to operate properly or does not have enough capacity. When installed in parallel with a downstream flow control valve(s), the standby device is referred to as a pressure under-ride and maintains a minimum pressure downstream
Transmission System	All deliveries and receipts, including the first cut regulator and relief valves at compressor stations
Worker/Monitor Regulation	Arrangements where two pressure reducing devices are installed in series to accomplish both primary and secondary pressure protection. Set point guidelines for worker/monitor regulation are found in *M.04 Pressure Protection and Relief Valve Capacity Verification*. Monitor regulators are installed either upstream or downstream of worker regulators and activate at a pressure slightly higher than the primary and standby regulators to provide backup pressure control if the worker regulator fails to operate properly

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7.0 Regulators – Test, Inspection, and Maintenance

The following procedures are described in this section:

- Prior to Test and Inspection
- Temporary Operations of Standby and Monitor Equipment
- Annual Test, Inspection, and Maintenance
- Five-year Overhaul

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Step	Activity
1	**INSPECT** equipment for leakage, proper installation, good mechanical condition, and protection from dirt, liquid, and physical damage.
2	**OBSERVE** for proper operation. **REFER** to manufacturer's literature for proper maintenance and checks. **REPAIR** or **REPLACE** as needed.
3	**COMPLETE** *Form 7-426 Small Regulator and Relief Valve Inspection* and **ATTACH** it to *EAM 7TG.25*.

7.3 MAOP/OPP Data Verification

The Asset Management Team or Work Crew performs the steps below to verify MAOP/OPP data.

Step	Activity
1	**RETRIEVE** the MAOP(s) for all pipelines and facilities from the most current data in the *GIS Database*.
2	**VERIFY** the data on the *EAM Work Order 7T-0107* is current.
3	From *EAM Work Order 7T-0107*, **RECORD** the following information for each similarly designed farm tap setting: • Overpressure Protection Pressure (OPP) • Overpressure Protection Setpoint (OPS)

7.4 Relief Valve Capacity Adequacy Verification

The Asset Management Team or Work Crew performs the following steps to verify relief valve capacity/adequacy data.

Step	Activity
1	**VERIFY** the tap information is correct and listed within the correct *EAM Work Order 7T-0106*. **REFER** to the corresponding *EAM Wrok Order 7T-0107* and manufacturer's literature for data verification.
2	**CONFIRM** the relief valve flow capacity is greater than or equal to the source flow capacity.
3	If the relief valve flow capacity is not equal to or greater than the source flow capacity, **INSTALL** additional relief valve(s) or **REPLACE** the inadequate relief valve with one that has adequate capacity. Another remedy for inadequate relief capacity is the installation of monitor regulators.
4	**COMPLETE** *EAM Work Order 7T-0106* for each similarly designed farm tap setting.

Code Reference:	**Procedure No.: M.06**	
49 CFR: 192.739	**Effective Date:** ***January 1, 2007***	**Page 4 of 11**

7.3 Annual Test, Inspection, and Maintenance

The Asset Management Team or Work Crew follows the steps and procedures below to verify a complete annual test, inspection, and maintenance of regulators.

CAUTION:
1. Take care to avoid spilling pipeline liquids on meter station floors or other surfaces.
2. Handle and dispose of pipeline liquids in accordance with the Environmental Procedures Manual.

Continued on next page

Step	Activity
~~1~~	~~**DOCUMENT** "as-found" set-point pressure.~~
~~2~~1	~~**CHECK** all system components for leaks to atmosphere.~~ **INSPECT** equipment for leakage, proper installation, good mechanical condition, and protection from dirt, liquid, and physical damage.
~~3~~2	**INSPECT** control, sensing, and supply lines for conditions that could cause improper operation.
~~4~~3	**INSPECT** vents for any blockage where vented to outside of building, where applicable.
~~5~~4	**VERIFY** proper lock up~~, per manufacturer's instructions~~.
~~6~~5	If lock-up cannot be obtained, **REPAIR** or **REPLACE** worn or damaged parts per manufacturer's instructions.

CAUTION: Remove regulator from service following ~~current~~ company *SOP K.36 Hazardous Energy Control (Lockout/Tagout)*. ~~PEPL/TGC/SR or CCE procedure regarding hazardous energy control (lockout/tagout).~~

Step	Activity
~~7~~6	**CHECK** instrument supply, gas systems, filters, and supply lines.
~~8~~7	**REPLACE** filter elements.
~~9~~8	**CLEAN** or **REPLACE** control components if applicable.
~~10~~9	**RETURN** regulator to service.
~~11~~10	**TEST** for proper operation at regulator set point(s). ~~**DOCUMENT** "as left" set-point pressure.~~
~~12~~11	**NOTIFY** Gas Control and other appropriate parties that activities are complete.
12	• For Category 1 Regulators: **RECORD** in *EAM 7T0104* the "As Found" and "As Left" set point pressures. • For Category 2 Regulators: **RECORD** in *EAM 7T0223* the "As Found" and "As Left" set point pressures. • For both Category 1 and Category 2 Regulators: **RECORD** maintenance and/or repair beyond set point adjustments in the applicable EAM Work Order Description Section.

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Code Reference :	**Procedure No.: M.02**	
49 CFR: 192.195, 192.199, 192.201, 192.605, 192.739	**Effective Date:** ***December 1, 2009***	**Page 4 of 13**

Step	Activity
2	**ADVISE** Gas Control and other appropriate parties before actuating automatic control valves. **MAKE** notification 24 hours in advance, if possible.
3	**VERIFY** that automatic control valve(s) are disarmed before testing the controls by **SWITCHING** the electronic control function to manual maintenance mode where applicable.
4	**VERIFY** the automatic control valve(s) will not accidentally open or close by **BLOCKING** the control signal to the valve actuator or manually **LOCKING** the valve in position, if required. **UTILIZE** bypass or standby control valves where available to maintain current control parameters.

NOTE: This need not be done if the automatic control valve(s) can be actuated fully without disruption of service.

CAUTION: Verify all valves are locked out and tagged out as specified in the company *SOP B.06 Hazardous Energy Control (Lockout/Tagout)*.

Step	Activity
5	**TEST** and **INSPECT** automatic control valves according to manufacturer's instructions in conjunction with remaining steps ~~5-11~~ 6-16.
6	**INSPECT** equipment for leakage, proper installation, good mechanical condition, and protection from dirt, liquid, and physical damage.
~~6~~7	**INSPECT** and **CLEAN** all system components~~, and CHECK for leaks~~.
~~7~~8	**REPAIR** or **REPLACE** worn or damaged parts per manufacturer's instructions.
~~8~~9	**CHECK** instrument supply gas system, filters, and the supply lines. **REPLACE** filter elements, and **CLEAN** or **REPLACE** control components, if applicable.
~~9~~10	**TEST** and **CALIBRATE** all pneumatic and electronic OPP controllers and operators for proper operation at set point(s) for all functions of the automatic control valve, locally and/or remotely, via gas control. **TEST** all other non-DOT control valves (i.e., meter run switching, zero flow AIV's, etc) controller outputs and operators for all functions of the automatic control valve. **TEST** and **CALIBRATE** line break controllers and operators for proper operation at set point for all functions of the automatic control valve. **TUNE** PID controller for proper operation, if applicable.
~~10~~11	**TEST** and **CALIBRATE** transducers/transmitters as applicable.
~~11~~12	For DOT Control Valves, **RECORD** in *EAM 7T0098* "As Found" and "As Left" set point pressures for all pneumatic and electronic OPP controllers.
~~12~~13	For Non-DOT Control Valves (i.e., meter run switching, line break, zero flow AIV's, etc.), documentation of set points is not required.

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Item 17

AVAILABLE ELECTRONICALLY
Panhandle Energy

WORK PERMIT: General Work ☐ Hot Work ☐

Location / Equipment Description: ____________________ **Issued To:** ____________________

Date Issued: Time Issued: ____ ☐ am ☐ pm Permit Expires: ____ ☐ am ☐ pm Date: ____

Work Description

☐ Remove or Replace ☐ Excavate ☐ Blinds ☐ Electrical Disconnect ☐ Operate PneumaticTools ☐ Heavy Equipment (ROW) ☐ Install/Remove ☐ Break Concrete ☐ Chipping Gun
☐ Hot Tap ☐ Sand Blast ☐ Temporary Lights ☐ Open Live Electric ☐ Burn ☐ Weld ☐ Grind ☐ Vehicle Entry ☐ Open Flame ☐ Other (Describe): ____________________

NOTE: ALL ATMOSPHERIC TESTING EQUIPMENT MUST BE CALIBRATED PER MANUFACTURING RECOMMENDATION AND CHECKED (BUMPED TESTED) BEFORE USE

Oxygen Test __________% By Volume
Instrument Number: __________
Time: ____ ☐ am ☐ pm

Flammable Gas Test: ________% LEL
Instrument Number: __________
Time: ____ ☐ am ☐ pm

Site Specific Toxic Gas tests Based on Potential Exposure
List Toxins and Concentrations in Parts Per Million:
____________________ PPM

Check All Boxes That Apply To This Job
THESE ITEMS MUST BE IN PLACE PRIOR TO BEGINNING WORK

FIRE PREVENTION

☐ Ignition Sources Identified
☐ LEL Gas Monitors
☐ Toxic Gas Monitors
☐ Fire Hose
☐ Non spark tools required
☐ Removal of Electronic Devices (Cell Phones, Blackberry, etc.)
☐ Fire Extinguisher
☐ Fire Blanket
☐ Fire Watch
☐ Gas Monitors

EXCAVATION

☐ One Call (811)
☐ Excavation Inspection Required
☐ Underground Line /Utilities Located
☐ Shoring Required
☐ Spotter Required
☐ Soft Dig
☐ Barricades Required
☐ Water Removal Required
☐ Emergency Egress Planned
☐ Excavation Competent Person Onsite

Qualified Persons Signature:

____
Signature

ENVIRONMENTAL REQUIREMENTS

☐ MSDS Available
☐ Container Labeling
☐ Waste Handling

P.P.E. REQUIREMENTS

☐ Basic P.P.E –Hard hats, Safety glasses with side shields, Safety toed shoes /boots, gloves,
☐ Hearing Protection
☐ Shin Guards
☐ Chemical Suit
☐ Fall Protection
☐ Fire Resistant Clothing
☐ Face Shield
☐ Toe Guards
☐ Chemical Boots
☐ Chemical Gloves
☐ SCBA
☐ Airline Respirator
☐ Purifying Respirator, List Cartridge Type: __________

ADDITIONAL P.P.E.

☐ Goggles
☐ Approved High Visibility Vest during work activities on heavily traveled roads/ highways. Use "FRC" vests when required.

ELECTRICAL

☐ Power Tools, GFCI Required
☐ Equipment Bonded and Grounded

OTHER REQUIREMENTS

☐ Crane critical lift plan in place
☐ Site Specific Hazards Explained

Job description:

SPECIFIC EQUIPMENT PREPARATION REQUIREMENTS

☐ Washed/Steamed
☐ Blocked/Blinded
☐ Drained/Depressurized
☐ Equipment In Service
☐ Locked/Tagged Out
☐ N2 Purged
☐ Confined Space Permit Required
☐ To Be Electrically Disconnected / Fuses Pulled By Qualified Person

Comments:

Special notes, procedures, requirements and precautions: ____________________
Has the job site been cleaned up as a condition of job completion ☐ Yes ☐ No ☐ N/A

THIS PERMIT VOID IF CONDITIONS CHANGE
This Permit Must Be Returned To The Issuer if Cancelled Or Time Of Expiration And Retained On File For 30 Days (General) or 1 Year (Hot)

Mandatory Signatures:

Permit issuer
(Authorized Employee / Job Supervisor): ____________________

Permit receiver
(Company / Contract Representative): ____________________

Distribution: **White Copy – Permit Issuer** **Yellow Copy – General Work** **Pink Copy – Hot Work**

Item 20

Code Reference :	Procedure No.: A.03	
49 CFR: 192.605, 192.909, and 192.911(k)	Effective Date: *December 19, 2008*	Page 5 of 19

Terms	Definitions
Standard Operating Procedure (SOP)	A written statement outlining a uniform method by which a policy, regulation, or approved activity will be carried out
Technical Discipline Director	The Director's in the Technical Services organization of Pipeline Integrity, Measurement and MEC.
Volume Owner	The Department Director or designee who manages all the documents contained within that volume

7.0 Management of Change Process

During the Management of Change process, company personnel follow the tasks and activities described in this section. The Management of Change process begins with identifying the need for a document modification and ends with distribution of a new or revised document. Use the CMR User's Guide in conjunction with this procedure.

The table below describes the overall Management of Change process. Refer to *Appendix B: The MOC Process* for a flowchart depiction of this process.

Stage	Description	Done by
1	**IDENTIFY** the need for change through annual review, Operational Compliance Audit or during day-to-day operations.	Panhandle Energy Personnel/Manager Audits/ Code Engineer
2	**DEVELOP** proposed change.	Panhandle Energy Personnel/ Manager Audits/ Divisions or Houston Management
3	**REVIEW** change and effects of proposed change. Approves or rejects.	Volume Owner/Document Owner
4	**REVIEW** the proposed change and approves or rejects.	Subject Matter Experts/Directors of Technical Operations (DTO)
5	**VERIFY** Collateral Impacts have been addressed.	Technical Discipline Director/Volume Owner
6	**DEVELOP** and **EXECUTE** a Change Implementation Plan	Technical Discipline Director

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Comment [meh1]: Change to address NOA requirement to observe activity to determine if a procedure change is needed

The procedures listed below describe the above process in greater detail.

- Identify the Need for Change
- Develop Proposed Change to Procedure
- Review Cycle
- Publication
- Change Implementation Plan
- Rejection of Proposed Change
- Waivers

Rec'd 12-28-10

U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

December 21, 2010

Mr. Eric J. Amundsen
Vice President – Technical Services
Panhandle Energy
5444 Westheimer Road
Houston, Texas 77056-6306

CPF 3-2010-1006M

Dear Mr. Amundsen:

On May 17-21, 2010, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Panhandle Energy procedures for operations and maintenance activities in Houston, Texas.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Panhandle Energy's (PE's) plans or procedures, as described below:

1. **§192.13 What general requirements apply to pipelines regulated under this part?**
   (c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

   §192.503 General requirements.
   (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until
   (1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure; and
   (2) Each potentially hazardous leak has been located and eliminated.

PE's procedures were inadequate because they did not define how much new pipe may be installed during a maintenance project before a "pre-test" is no longer sufficient and a post-construction hydrostatic test becomes necessary.

2. **§192.225 Welding Procedures**
(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

PE's procedures were inadequate because they did not require that the welding process qualification test records to be retained.

3. **§192.231 Protection from weather.**
The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

PE's procedures were inadequate because they did not define what constitutes adverse weather conditions that would require protection to ensure the quality of the welding was not impaired.

4. **§192.241 Inspection and test of welds.**
(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:
(1) The welding is performed in accordance with the welding procedure; and
(2) The weld is acceptable under paragraph (c) of this section.

PE's procedures were inadequate because they did not require welding inspectors to be qualified to conduct visual inspections.

5. **§192.241 Inspection and test of welds.**
(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:
(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

PE's procedures were inadequate because they did not define what constitutes "limited in number" such that non-destructive testing becomes impractical.

6. **§192.245 Repair or removal of defects.**

(a) Each weld that is unacceptable under §192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

PE's procedures are inadequate because they reference the wrong sections of API 1104 for repairing or removing weld defects.

7. **§192.605 Procedural manual for operations, maintenance, and emergencies**

Each operator shall include the following in its operating and maintenance plan:

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

> **(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.**

§192.612 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

PE's procedures for assessing the risk of these pipelines were inadequate because they did not contain sufficient criteria and/or weighting guidance to ensure consistent application.

8. **§192.605(b)(1) See Above**

§192.612 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall -

> **(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center;**

PE's procedures were inadequate because they did not delineate the extent of marking required when the operator discovers a pipeline is exposed on the seabed or constitutes a hazard to navigation.

9. **§192.605(b)(1) See Above**

§192.612 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.
(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall -

> **(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.**

PE's procedures were inadequate because they did not require PE to provide the necessary cover over the pipeline when it discovers that a pipeline is exposed on the seabed or constitutes a hazard to navigation.

10. **§192.605(b)(1) See Above**

§192.625 Odorization of gas.
(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

> **(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;**
> **(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:**
>> **(i) An underground storage field;**
>> **(ii) A gas processing plant;**
>> **(iii) A gas dehydration plant; or**
>> **(iv) An industrial plant using gas in a process where the presence of an odorant:**
>>> **(A) Makes the end product unfit for the purpose for which it is intended;**
>>> **(B) Reduces the activity of a catalyst; or**
>>> **(C) Reduces the percentage completion of a chemical reaction**
>
> **(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location.; or**
> **(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.**

PE's procedures were inadequate because they did not include provisions for determining which segments of its transmission pipelines and laterals that are partially located in Class 3 and 4 locations must be odorized in accordance with paragraph (a).

11. §192.605(b)(1) See Above

§192.707 Line markers for mains and transmission lines.
(d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

> **(2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.**

PE's procedures were inadequate because they still allowed marker signs to be labeled with a telephone number for the public to call collect, even though that option is no longer available through the phone service.

12. §192.605(b)(1) See Above

§192.727 Abandonment or inactivation of facilities.
(d) Whenever service to a customer is discontinued, one of the following must be complied with:

> **(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.**
> **(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.**
> **(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.**

PE's procedures were inadequate because they did not include a requirement to utilize one of the three acceptable methods to ensure that gas flow will be prevented whenever service to a customer is discontinued.

13. §192.605(b)(1) See Above

§192.727 Abandonment or inactivation of facilities.
(g) 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.

PE's procedures were inadequate because they did not require reports to be filed when an underwater pipeline facility crossing a navigable waterway is abandoned.

14. §192.605(b)(1) See Above

§192.735 Compressor stations: Storage of combustible materials.
(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

PE's procedures were inadequate because they did not define what constitutes a combustible material or what quantities are considered necessary for everyday use.

15. §192.605(b)(1) See Above

§192.739 Pressure limiting and regulating stations: Inspection and testing.
(a) Each pressure limiting station, relief device (except rupture discs), and Pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is–

PE's procedures were inadequate because they did not include fuel gas regulators as subject to the annual inspection and testing requirements.

16. §192.605(b)(1) See Above

§192.739 Pressure limiting and regulating stations: Inspection and testing.
(a) Each pressure limiting station, relief device (except rupture discs), and Pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is–

> **(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.**

PE's procedures (G.25, M.06, and M.02) were inadequate because they did not include provisions for inspecting the applicable pressure control devices to ensure they are properly protected from dirt, liquids, and other conditions that may prevent proper operation.

17. **§192.605(b)(1) See Above**

§192.751 Prevention of accidental ignition.
Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:
(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

PE's procedures were inadequate because they did not clearly require the removal of potential ignition sources, such as cell phones, in areas where a hazardous amount of gas was being vented into open air.

18. **§192.605 Procedural manual for operations, maintenance, and emergencies**
(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.
(2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part.

§192.453 General.
The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

PE's procedures were inadequate because they did not contain provisions that require the corrosion control program to be carried out by or under the direction of a qualified individual.

19. **§192.605(b)(2) See Above**

§192.463 External corrosion control: Cathodic protection.
(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

PE's procedures are inadequate because they do not properly consider voltage drops other than those across the structure-electrolyte boundary as required when interpreting the criteria contained in Appendix D. When PE obtains readings that demonstrate inadequate cathodic protection when such voltage drops are eliminated (i.e. instant-off cathodic protection data), PE's procedures do not require PE to verify a different criterion has been met or to remediate the deficiency in its program for controlling corrosion.

20. §192.605 Procedural manual for operations, maintenance, and emergencies Each operator shall include the following in its operating and maintenance plan: (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedure when deficiencies are found

PE's procedures were inadequate because they did not contain detailed provisions for periodically reviewing the work done by its employees to determine the effectiveness and adequacy of its procedures.

<u>Response to this Notice</u>

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 45 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 3-2010-1006M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

David Barrett
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

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

Response Options for Pipeline Operators in Compliance Proceedings

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

Be advised that all material submitted by a respondent in response to an enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

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

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

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

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

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

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

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

b. <u>When the Notice contains a proposed **COMPLIANCE ORDER*** --</u>

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

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

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

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

c. <u>When the Notice contains a **WARNING ITEM** --</u>

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

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

II. <u>Procedures for Responding to a NOTICE OF AMENDMENT*--</u>

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

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

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

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

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

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

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

III. Procedure for Requesting a Hearing

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

IV. Extensions of Time

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

V. Freedom of Information Act

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

VI. **Small Business Regulatory Enforcement Fairness Act Information**

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

VII. **Payment Instructions**

Civil Penalty Payments of Less Than $10,000

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

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

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

Civil Penalty Payments of $10,000 or more

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

INSTRUCTIONS FOR ELECTRONIC FUND TRANSFERS

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

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

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

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

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

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

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

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

February 2009