



West Texas Gas and its Subsidiaries and/or Affiliates
West Texas Gas Utility, LLC 22435
Western Gas Interstate Company 22462
WTG Gas Transmission Company 31968

March 2025

1.0 Review and Revision Log

This plan of Operating, Maintenance and Emergency Procedures must be reviewed at least once each year or no more than 15 months to make certain the information is current. Any changes in operations, in operating technology, or in established procedures will be reflected in these reviews and/or revisions.

Review/Revision Date	Signature of Reviewing Supervisor	Revision Description
June 2008		Complete manual overhaul.
March 2009		Ensured LA, NM, OK, and NM state regulations were included in the manual. Added distribution line information. Update Material Incorporated by Reference to reflect changes in CFR. Added State cross references.
August 2009		Update procedures P-192.225, P-192.513, P-192.614 and P-192.739. Updated form F-192.517 and created form F-192.513. Update form listing.
September 2009		Update Forms F-191.25 and WTG 1102. Update Form listing and Regulatory Compliance Tables (p24 – 26)
November 2010		Manual updated to reflect changes in CFR. Updated procedures P-191.5, P-192.231, P-192.245, P-192.281, P-192.319, P-192.483 to reflect changes in CFR and updates in WTG operating practices.
March 2011		Updated Forms list, Specifics section, and made general revisions to manual. Updated formatting of all forms and procedures for consistency. Updated Forms F-192.305, F-192.706, F-192.711, WTG 1103. Updated Procedures P-191.5, P-191.17, P-191.23, P-192.5, P-192.23, P-192.241, P-192.305, P-192.319, P-192.351, P-192.455, P-192.459, P-192.461, P-192.465(a), P-192.465(e), P-192.465(c), P-192.473, P-192.483, P-192.605(b)(9), P-192.614, P-192.615, P-192.617, P-192.706, P-192.706(b), P-192.707, P-192.711, P-192.731(a), P-192.731(c), P-192.736, P-192.739, P-OCC-165:45-9-2-1, P-TAC 8.205

Review/Revision Date	Signature of Reviewing Supervisor	Revision Description
July 2011		Added procedure P-192.487 and updated procedures P-192.483 and P-192.706. Updated procedures list, regulatory cross-references, and PHMSA advisory bulletins.
August 2011		Updated form F-191.1 and procedure P-191.5.
October 2011		Updated procedure P-192.553 Uprate Pipeline to include new OQ requirements and non-hazardous leak information.
November 2011		Updated Table 3.3.1.3 to include P-192.625 in odorant concentration tests.
January 2012		Updated Form WTG-1101 to include revision date on all pages and update header format. Updated F-192.513 to correct referenced procedure. Added P-TAC8.225 and from WTG-1400 to manual. Updated P-192.459 and P-192.513 to include WTG 1400.
January 2013		Update Forms: F-192.706, WTG1200, WTG1203, & WTG1400. Add F-192.706(a), F-192.619(b) & WTG1304 Update procedures P-192.619 and P-192.706. Added requirement to Verify the Completion of all School Piping Tests. Remove Advisory Bulletins and add statement that they are reviewed during the annual review.
December 2013		As a result of WTG's Annual O&M Review WTG updated all procedures to contain Company specific information.
August 2014		Updated the following procedures to contain company specific information. 192.273, 192.513, 192.605(c), 192.605(b)(8), 192.615, and 192.706(b). TAC 8.205 was completely removed and merged into 192.706(b) Added procedure number 192.709(b) to comply with CFR 192.709.
September 2014		Added section 5.4 Management of Change

Review/Revision Date	Signature of Reviewing Supervisor	Revision Description
April 2016		Updated procedures 192.5, 192.605(c), 192.619, 192.625, 192.711
November 2017		Updated procedures 192.105, 192.455, 192.465(a), 192.465(b), 192.629, 192.501, 192.553 P-WTG-Pigging and Forms F-192.465(B), F-192.517
March 2018		Updated Project Form WTG-1400 and Leak Report Form WTG-1101 to include new systems
December 2018		Updated procedures 192.105, 192.273, 192.281, 192.305, 192.319, 192.351, 192.455, 192.461, 192.513, 192.605(b)(5), 192.605(b)(6), 192.605(b)(7), 192.613, 192.627, 192.67, 192.629, 192.711, 192.739, 192.745, 192.749. And Form WTG1-1400
July 2019		Updated procedure 192.281 due to regulatory changes
August 2019		Updated procedures 192.351 and 192.739 due to regulatory changes
April 2020		Updated procedures 191.23, 192.5, 192.8, 192.67, 192.105, 192.225, 192.281, 192.501, 192.619, WTG-PIGGING due to mega-rule changes Renamed 192.67 to 192.69 New procedure – 192.607, 192.127, 192.712 – Updated OMER front section
May 2020		Updated procedures 191.17, 191.5, 192.553, P-TAC 8.230
October 2020		Updated procedures 192.707 per PHMSA audit, 192.69
January 2021		Updated procedures 192.605(b)(a), 192-461, 192.459, 192.273, 192.605(b)(7), 192.605(b)(6), 192.605(b)(5), 192.465(a), 191.5, 192.225, 192.481, 192.501, 192.619 – CFR Changes and Manager's Review
March 2021		Updated procedures 192.105, 192.281, 192.319, 192.351, 192.465(b) – CFR Changes and Manager's Review

Review/Revision Date	Signature of Reviewing Supervisor	Revision Description
April 2021		Update procedure 192.629 - Purging
July 2021		Update procedures 192.105, 192.605(b)(6), 192.727
October 2021		Implemented mitigations for GHG emissions
November 2021		Update procedures 192.105, 192.706(b), 192.163, 192.605(b)(7)
January 2022		Update procedures 192.8, 192.711, 192.739, 192.745, P-192.225 and forms 192.8, WTG1102, WTG-1202, WTG-1200
February 2022		Update WTG-1101 and WTG-1400 with new systems and format changes
April 2022		Revised and updated the GHG Emissions
May 2022		Update procedures 192.739, 192.105 and form WTG 1102
June 2022		Update OMER and P-192.731(a)(b)(c) – GHG – In OMER removed references to Louisiana
July 2022		Update P-191.5 – incident factor inflation increase P-192.8, P-192.617
August 2022		Update P-192.69 – include steel pipe storage and handling P-192.634, P-192.745
October 2022		Update OMER, P-192.706 and P-192.706(b) added definition for Segment
November 2022		Update P-192.225
December 2022		WTG-1301 Odorant Form Rewrite. P192.513 ensure EFV in the test are in open position

Review/Revision Date	Signature of Reviewing Supervisor	Revision Description
January 2023		Update P-192.281, P-192.465,P-192.605(b)(5)
April 2023		Mega Rule Updates – OMER, P-192.18, P-192.465(d), P-192.319, P-192.105, P-192.281, P-192.473, P-192.461, MOC Process Procedure and New MOC-PO Form
May 2023		Update 192.605(c), P-192.619, P-192.706, P-192.749, new procedure P-192.613
October 2023		Update 192.706
February 2024		Update P-192.745, P-192.745, WTG-1104
July 2024		MOC Process, Threshold change, Kansas edits, P-192.305, P-192.501, P-OCC-165-45-9-2.1
March 2025		Added New Procedure 192.5.1

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2.0 INTRODUCTION

2.1 How to Use This Manual

This manual is intended to provide the information necessary for compliance with 49 CFR Part 191 and 192. It also contains in-depth information for specific purposes. The manual can be used for training, for a reference, and for a routine operations tool.

Data and procedures unique to individual pipeline systems may be found in the Pipeline Specific Operations Manual (PSOM) for the particular system.

The sections of this manual are described below. The manual is designed so that an employee already familiar with the facility, the procedures, and the regulations can turn straight to the appropriate section and begin work. However, we strongly recommend a first-time user review the entire manual. A Revision Log and a Table of Contents follow this page.

NOTE: Users wanting to know “what to do” and “how to do it” should see the Overview, Procedures, and Forms sections.

The **Overview** section contains general information intended for all readers. It briefly describes the pipeline’s operation, location, equipment and facilities, applicable rules, and compliance requirements.

The **Specifics** section provides more detailed information for supervisors and compliance personnel regarding the facilities, scheduled responsibilities, and compliance requirements.

The Procedures section contains procedures for use by employees actually performing these tasks.

The **Definitions** section contains Federal and State specific definitions.

The **Forms** section contains forms to accompany the procedures. It is highly recommended that copies be made of these forms rather than marking the originals.

2.2 Manual Distribution

This manual will be submitted to state regulating agencies upon request..



2.3 Acronyms

The following acronyms are used throughout this manual:

AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
CFR	Code of Federal Regulations
DOT	Department of Transportation (Federal)
ECA	Engineering Critical Assessment
ERW	Electric Resistance Welded
FERC	Federal Energy Regulatory Commission
HCA	High Consequence Area
MAOP	Maximum Allowable Operating Pressure
MCA	Medium Consequence Area
MOC	Management of Change
MSS	Manufacturers Standardization Society
NDT	Non-Destructive Testing
NFPA	National Fire Protection Association
NGPSA	Natural Gas Pipeline Safety Act
NMPRC	New Mexico Public Regulation Commission
NRS	National Response Center
OCC	Oklahoma Corporation Commission
OCS	Outer-Continental Shelf
OMB	Office of Management and Budget
OPID	Operator ID – (PHMSA Issued)
PIR	Potential Impact Radius
PHMSA	Pipeline and Hazardous Materials Safety Administration
SMYS	Specified Minimum Yield Strength
TAC	Texas Administrative Code



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TRRC	Texas Railroad Commission
WGI	Western Gas Interstate, LLC
WTG	West Texas Gas Utility, LLC
WTGGT	WTG Gas Transmission Company, LLC



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3.0 OVERVIEW

The Overview section is designed for all readers of this manual and consists of the subsections below. Readers needing practical information (*what to do*, *when*, and *how*) should also refer to the Procedures and Forms sections.

Types of DOT Regulated Pipelines (Subsection 2.1): Describes the type of gas pipelines regulated by the DOT, Texas RRC, OCC and New Mexico Commission and the differences between them.

Description of Facilities (Subsection 2.2): Explains the function of the pipelines. Jurisdictional equipment is shown in appropriate PSOM.

Location (Subsection 2.3): Gives the exact location of the pipelines, as shown on the maps in Figure 2.

3.1 Types of DOT Regulated Pipelines

3.1.1 Transmission

Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that:

- (1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;
- (2) Has an MAOP of 20 percent or more of SMYS;
- (3) Transports gas within a storage field;

Note 1 to *transmission line*. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

3.1.2 Gathering

A pipeline that transports gas from a current production facility to a transmission line or main. Reference CFR 192.8 and API RP 80 for detail in determining specific starting points and ending points of a gathering system.

Regulated gathering pipelines are divided into four types which determines the requirements an operator must comply with.

3.1.3 Regulated Gas Gathering

Type	Feature	Area	Safety Factor
A	Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is	Class 2, 3, or 4 location (see §192.5)	None.



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Type	Feature	Area	Safety Factor
	unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part Non-metallic and the MAOP is more than 125 psig (862 kPa)		
B	Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part Non-metallic and the MAOP is 125 psig (862 kPa) or less	<i>Area 1.</i> Class 3 or 4 location <i>Area 2.</i> An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: - Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; - If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or - Non-metallic and the MAOP is more than 125 psig (862 kPa)	<i>Class 1 location</i>	None
R	- All other onshore gathering lines	Class 1 and Class 2 locations	None

3.1.4 Distribution

Distribution line means a pipeline other than a gathering or transmission line



3.2 Pipeline Location

This manual covers pipelines owned and operated by West Texas Gas and its affiliates. These pipelines include interstate transmission lines in Oklahoma, New Mexico and Texas. Also included in the manual are intrastate pipelines as follows:

- Transmission in New Mexico, Oklahoma, Texas
- Distribution in Texas, Oklahoma



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SPECIFICS

This section contains detailed information on the pipeline applicable regulations and standards, and compliance requirements.

Applicable Regulations and Standards (Subsection 3.1): What is applicable, what the rules require for equipment and tasks.

Material Incorporated by Reference (Subsection 3.2): Current additions of documents incorporated by reference can be found at 49 CFR 192.7

Compliance Requirements (Subsection 3.3): Covers the following items:

- Routine Compliance Requirements
- Contingent Requirements
- Recordkeeping Requirements
- Notification and Reporting Requirements
- Manual(s) Requirements
- Emergency Manual Requirements

3.3 Applicable Regulations and Standards

West Texas Gas's Pipelines are regulated by 49 CFR Parts 191 and ,192, and 199 and applicable state regulations as follows:

3.3.1 Federal Regulations

49 CFR Part 191 -Current rules can be found online at the following website:
<https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-191>

49 CFR Part 192 -.Current rules can be found online at the following website:
<https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192>

49 CFR Part 199 -.Current rules can be found online at the following website:
<https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-199>

3.3.2 State Regulations

3.3.2.1 TEXAS

Texas Regulation Title 16 TAC. . Current rules can be found online at the following website:
[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=8](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=8)

3.3.2.2 OKLAHOMA

Oklahoma Regulation Title 165 Chapter 20. Current rules can be found online at the following website:
<https://oklahoma.gov/occ/rules/current-rules.html>



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3.3.2.3 NEW MEXICO

New Mexico Regulation. Current rules can be found online at the following website:
<http://www.nmprc.state.nm.us/transportation/pipeline-safety.html>

3.4 Internal Documents by Reference

The following company documents are also incorporated into this manual by reference:

- Pipeline Specific Operations Manual (PSOM)
- WTG Emergency Response Plan
- OQ Manual
- IM Manuals (Distribution and Transmission)
- Damage Prevention Plan
- Drug and Alcohol Plan

3.5 Compliance Requirements

This is a summary of the routine tasks and contingent requirements required for compliance, the forms required for documentation, the records that must be kept and the retention time on the records.

3.5.1 Routine Compliance Requirements

The regulations require numerous operations and maintenance tasks be performed on a routine basis. The frequency of these requirements can be found in the procedure or form documents.

3.5.2 Contingent Requirements

In addition to the routine requirements previously discussed, the regulations require contingent requirements. These requirements are required as the result of another event. For instance, when a pipeline is exposed, it must be inspected for damage. The tables below summarize these requirements and give the forms that should be used to document the activity. Refer to the



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Recordkeeping portion of this section to determine the retention time for the records.

3.5.2.1 If/Then Compliance Requirements for Transmission Pipelines, Distribution Pipelines and Type A Gathering Pipelines

If...	Then See Form #¹
There is a reportable incident on the pipeline	F-191.1 (Transmission or Gathering) F-191.9 (Distribution)
There is a safety-related condition on the pipeline	F-191.25
Pipeline repairs are to be done or the pipeline extended.	F-192.225, F-192.305, F-192.709, WTG-1100
Pipeline is hydro-tested	F-192.517
Pipeline is abandoned	F-192.727
There is a pipeline emergency	F-192.615
There is a new encroachment on the pipeline	F-192.614
Pipeline crosses foreign lines	F-192.614
Pipeline is exposed / cut	WTG-1100, WTG-1400
MAOP must be determined	F-192.619
There is a line locate request from one call system	One Call ticket
There is excavation on the pipeline right-of-way	F-192.614
There is an increase in population	F-192.5
A new pipeline is installed	F-192.5, F-192.517, F-192.619, WTG-1400

Note: This list does not include contingency requirements that arise during an inspection.



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If/Then Compliance Requirements for Type B Gathering Pipelines

If...	Then See Form #...
There is a reportable accident on the pipeline	F-191.1
There is a safety-related condition on the pipeline	F-191.25
Pipeline is hydro-tested	F-192.517
Pipeline is abandoned	F-192.727
There is a pipeline emergency	F-192.615
There is a new encroachment on the pipeline	F-192.614
Pipeline crosses foreign lines	F-192.614
Pipeline is exposed / cut	WTG 1100, WTG 1400
MAOP must be determined	F-192.619
There is a line locate request from one call system	One Call Ticket
There is excavation on the pipeline right-of-way	F-192.614
There is an increase in population	F-192.5
A new pipeline is installed	F-192.5, F-192.517, F-192.619, WTG 1400

Note: This list does not include contingency requirements that arise during an inspection.

3.5.3 Recordkeeping Requirements

Required recordkeeping includes maintaining records of pipeline construction, corrosion control, pressure testing, operation/maintenance, and operator qualification, which are reviewed below, with forms to use, length of retention, required data, and relevant regulation provision.

These records are stored in the web-based “WTG Compliance” Database or filed in the District office. Operators shall maintain the most current record or records for at least five years if no other time period is prescribed by Parts 192, 192, 199 or Title 16, Chapter 8.

3.5.3.1 Pipeline Records:

The following records must be kept on all pipelines:

1. All design and installation of new and used pipe, including design pressure calculations, pipeline specifications, specified minimum yield strength, wall thickness calculations, location of each valve, fitting, fabricated branch connection, closure, station piping, and fabricated assembly;
2. All pipeline construction, procedures, training, and inspection pertaining to welding, nondestructive testing, and cathodic protection;
3. All hydrostatic testing performed on all pipeline segments, components, and tie-ins; and



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4. The performance of the procedures outlined in this manual.

3.5.3.1.1 Corrosion Control Records:

1. Per 192.491(a) keep for the life of the pipeline records or maps to show the location of cathodically protected pipeline, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system.
2. Per 192.491 keep for at least 5 years (records relating to 192.465(a) and (e) and 192.475(b) must be kept for the life of the pipeline) records of each test, survey, or inspection required by Subpart I. These include:
 - a. Inspection of Exposed Pipe (192.459)
 - b. Cathodic Protection Survey (Life 192.465(a))
 - c. Inspection of Rectifiers (192.465(b))
 - d. Inspection of Revised Current Switches, Diodes and Interference Bonds (192.465(c))
 - e. Reevaluation of Unprotected Facilities (Life 192.465(e))
 - f. Inspection of Internal Service of Removed Pipe (Life 192.475)
 - g. Inspection of Coupons (192.477)
 - h. Inspection for Atmospheric Corrosion (192.479)

3.5.3.1.2 Pressure Testing

1. If standard pressure testing is used, per 192.505 and 192.507, keep the record of the latest test as long as the pipeline tested is in use. The record must show the following:
 - a. Name of the operator, the name of the operator's employee responsible for making the test, and the name of the test company used, if any;
 - b. Test medium;
 - c. Test pressure;
 - d. Test duration;
 - e. Pressure recording charts, or other record of pressure readings;
 - f. Elevation variations, whenever significant for the particular test;
 - g. Leaks and failures noted and their disposition.
2. Maintain a record of each test performed under 192.509, 192.511, and 192.513 for at least 5 years.



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3.5.3.1.3 Pipeline Upgrading

Per 192.553, keep for the life of the pipeline segment a record of each investigation required by Subpart K, of all work performed and of each pressure test conducted.

3.5.3.1.4 Operation and Maintenance Records

1. Keep the records of repairs to pipe showing the date, location, and description of each repair made as long as the pipe is in service.
2. Keep the records of repairs to non-pipe components showing the date, location, and description of each repair for at least five years.
3. Keep records of each inspection and test in Subpart L or M for at least five years or until the next inspection or test is performed, whichever is longer. This covers such areas as:
 - i. Line markers
 - j. Change in class location
 - k. Inspection of rights-of-way
 - l. Leakage surveys
 - m. Valve maintenance
 - n. Pipeline repairs
 - o. Pressure limiting and regulating devices
 - p. Overpressure safety devices
 - q. Signs
 - r. Public education

3.5.3.1.5 Operator Qualification Records

1. Per 192.807, keep records supporting an individual's current qualification while the individual is performing the covered task.
2. When individual no longer performs that task, store records for five years.

NOTE: Readers should refer to the written Operator Qualification Plan for information on these records.

The table below gives a summarized list of the required records and the regulation citation that requires the record to be retained.



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3.5.4 Necessary Compliance Records (All Types of Pipelines)

Record	Retention Time If DIMP related keep records for 10 years	Retention Citation
Transmission and Gathering Systems: Annual Report (PHMSA F-7100.2-1)	5 years	
Distribution Systems: Annual Report (PHMSA 7100.1-1)	5 years	
Safety-related Condition Reports	5 years	
Welding – Procedure	As long as pipeline is in use	192.225(b)
Welding - Welder Qualification	Life of the Pipeline	
NDT – NDT Personnel Qualification	Life of pipeline	
NDT Records	Life of pipeline	192.243(f)
Exposed Pipe Inspection	5 years	192.491(c)
Annual Pipe-to-soil Monitoring	Life of pipeline	192.491(c)
Rectifier Inspection	5 years	192.491(c)
Interference Bond Monitoring	5 years	192.491(c)
Prompt Remedial Actions	Life of pipeline	192.491(c)
Unprotected Pipeline Surveys, CP active corrosion areas	5 years	192.491(c)
Electrical Isolation	5 years	192.491(c)
Test Stations – Significant Number	Life of pipeline	192.491(b)
Test Lead Maintenance	5 years	192.491(c)
Interference Currents	5 years	192.491(c)
Internal Corrosion – Corrosive Gas Investigation	5 years	192.491(c)
Internal Corrosion – Internal Surface Inspection; Pipe Replacement	Life of pipeline	192.491(c)
Internal Corrosion Control Monitoring	5 years	192.491(c)
Atmospheric Corrosion Control Monitoring	5 years	192.491(c)
Remedial – Replaced or Repaired Pipe; Coated and Protected; Corrosion Evaluation and Actions	Life of pipeline	192.709(a)
Corrosion Control Maps / Record of Installation	Keep current	192.491(a)
Pressure Testing	Keep current	192.517
Manual Review	5 years	192.709(c)



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Record	Retention Time If DIMP related keep records for 10 years	Retention Citation
System Maps	Keep current	
Abnormal Operations	5 years	192.709(c)
Class Location Study	5 years	192.709(c)
Damage Prevention	5 years	192.709(c)
Liaison With Officials	5 years	192.709(c)
Public Education	5 years	192.709(c)
Maximum Allowable Operating Pressure (MAOP)	Life of pipeline	192.709(c)
Odorization of Gas		192.709(c)
Patrolling	5 years	192.709(c)
Leak Surveys	5 years	192.709(c)
Repair	5 years– Non pipe Life of pipeline – pipe	192.709(c)
Compressor Station Relief Device	5 years	192.709(c)
Compressor Station Emergency Shutdown	5 years	192.709(c)
Compressor Stations – Detection and Alarms	5 years	192.709(c)
Pressure Limiting and Regulating Stations	5 years	192.709(c)
Pressure Limiting and Regulating Stations - Capacity	5 years	192.709(c)
Valve Maintenance	5 years	192.709(c)
Vault Maintenance	5 years	192.709(c)

3.5.5 Notification and Reporting Requirements

The following is a summary of the different notifications reports that are required by the pipeline regulations. The procedures and rules should be referenced to ensure that all reports are filed accurately and in the appropriate time frame.

Each form is numbered by the corresponding section that requires it.

1. Annual Report. filed online at PHMSA portal at <https://portal.phmsa.dot.gov..>
 - a. Filed by operators of transmission lines and gathering lines;
 - b. Completed West Texas Gas Compliance Department;
 - c. Due by March 15 for previous calendar year.
2. Reporting Incidents::



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- a. Filed online at PHMSA portal at <https://portal.phmsa.dot.gov>.
3. Reporting Safety Related Conditions
 - a. Emailed to: informationresourcesmanager@dot.gov
4. NPMS Submittal: Update submittal information by March 15. Refer to procedure P-191.17.

NOTE: The Procedures section has additional information.

3.5.6 PHMSA Reporting Requirement

PHMSA	Type of Report/Notification	Requirement
PHMSA	Annual Report	See P-191.17
	Incident/Accident Report	See P-191.5
	Safety-Related Condition Report	See P-191.23
	Pre-Construction, Conversion or Commodity Change Notification	Not later than 60 days before: construction or modification of pipeline facilities > \$10 million or 10 miles; construction of a new LNG facility; construction of a new underground gas storage facility; reversal of product flow expected > 30 days; conversion to service; or change in commodity
	Other Notification	Not later than 60 days after: change in primary entity responsibility; name of the operator; change in entity; acquisition or divestiture >=50 miles, LNG facilities, or underground gas storage facilities

3.5.7 State Notification and Reporting Requirements

State	Type of Report/Notification	Requirement
New Mexico	Annual Report	See P-191.17
	Incident/Accident Report	See P-191.5
	Safety-Related Condition Report	See P-191.23



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State	Type of Report/Notification	Requirement
	Pre-Construction Notification	<p>18.60.2.9 NOTICE OF INTENT TO CONSTRUCT: Prior to the start of construction of any new or replacement intrastate natural gas pipeline with a total construction value of \$50,000 or more, the operator of such pipeline shall give written notice of its intent to construct to the Transportation Division Director, Post Office Box 1269, Santa Fe, New Mexico, 87504-1269. The notice of intent to construct shall state:</p> <ul style="list-style-type: none"> A. the pipe material; B. the finished diameter, length, and approximate location of the pipeline; C. the size and capacity of any compressors or pumps; D. and the contemplated date construction will commence.
	Reports of Master Meters	Annually, by March 15 th , report to the director the name, address, and location of any master meter operators connected to West Texas Gas facilities.
Oklahoma	Annual Report	See P-191.17
	Incident/Accident Report	See P-191.5
	Safety-Related Condition Report	See P-191.23
Oklahoma (Cont'd)	Pre-Construction Notification	Prior to construction of a new pipeline, or relocation or replacement of a pipeline 1.) complete and file Form 5001 with the Commission and mail 7 days prior to the commencement of construction, relocation or replacement or; 2) If an emergency, give telephonic notice of emergency construction, relocation or replacement to the Pipeline Safety Department of the Commission followed by mailing Form 5001 within 5 work days after telephonic notice is given. Applies to pipelines only over 1 mile.
	Permitting	None
	Change of Ownership Notification	Upon the finalization of an agreement to purchase or sell a regulated gas pipeline submit a written notification within five working days.
	Notice of evacuation of a building	See P-192.615
Texas	Annual Report	See P-191.17
	Incident/Accident Report	See P-191.5

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State	Type of Report/Notification	Requirement
Transmission And Gathering Distribution	Safety-Related Condition Report	See P-191.23
	Pre-Construction Notification	<p>File Form PS-48 if construction of a new, relocated, or replacement pipeline 10 miles in length or longer including liquified petroleum gas distribution systems, natural gas distribution systems, and master meter systems 10 miles in length or longer, an operator shall notify the Commission not later than 60 days before construction or for construction of a new, relocated, or replacement pipeline at least one mile in length but less than 10 miles, an operator shall notify the Commission not later than 30 days before construction.</p> <p>https://www.rrc.texas.gov/pipeline-safety/pipeline-safety-forms/</p> <p>For sour gas pipelines and/or pipeline facilities, as defined in §3.106(b) of 16 TAC Chapter 8 (relating to <i>Sour Gas Pipeline Facility Construction Permit</i>), a new construction report and Form PS-79, <i>Application for a Permit to Construct a Sour Gas Pipeline Facility</i> will be filed 30 days prior to construction.</p>
	Permitting	T-4 Permit to Operate Pipeline filed online RRC Site
	Change of Ownership Notification	Adopts CFR regulations.
	Construction, Relocation or Replacement of a Pipeline Greater than One (1) Mile	Adopts CFR regulations. New construction on natural gas distribution or master meter systems of less than 1 mile is exempted.

3.5.8 Manual(s) Requirements

Section 192.605 requires preparation and annual updating of a manual. It lists five areas of necessary information:

1. General [192.605(a)],
2. Maintenance and normal operations [192.605 (b)],
3. Abnormal operations [192.605 (c)],
4. Safety-related condition reporting [192.605(d)], and
5. Surveillance, emergency response, and accident investigation [192.605(e)].

The following list of required items can be used in the yearly review. Refer to the appropriate place in the Rules section for detailed information when revising.



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General - Appropriate parts are kept where operations and maintenance activities are conducted.

Maintenance and Normal Operations - Procedures are included in the manual as follows:

- To operate, maintain, and repair the pipeline system in according to each requirement of Subparts L and M.
- To control corrosion in accordance with the operations and maintenance requirements of Subpart I.
- To make construction records, maps, and operating history readily available
- To gather data needed for reporting accidents
- To start up and shut down any part of the pipeline system complying with §192.619.
- To maintain compressor stations and isolate for purging before returning to service
- Starting. Operating and shutting down gas compressor units.
- To determine the pipeline facilities requiring immediate response to protect the public in an emergency.
- To analyze pipeline accidents to determine their causes.
- To minimize the potential for hazards and recurrence.
- To monitor a pipeline unequipped to fail safe during startup and shut-in - complying with §192.605.
- To detect abnormal operating conditions and transmit this data to an attended location.
- To safely abandon pipeline facilities.
- To minimize the risk of accidental ignition of vapors.
- To establish and maintain liaison with fire, police, and other appropriate public officials.
- To review the work done by operator personnel to check (and correct) the effectiveness of the procedures.
- To protect personnel in excavated trenches from accumulations of vapor or gas, providing appropriate safety and rescue equipment.
- To systematic and routinely test and inspect pipe-type or bottle-type holders including:
 - Detecting external corrosion before the strength of the container had been impaired;
 - Periodic sampling and testing of as in storage to determine the dew point of vapors contained the stored gas;
 - Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

Abnormal Operation - Procedures emphasizing safety are included as follows:

- To provide safety when responding to, investigating, and correcting the cause of:
 - Unintended closure of valves or shutdowns;



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- Increase or decrease in pressure or flow rate outside normal operating limits;
 - Loss of communications;
 - Operation of any safety device;
 - Any other malfunction, deviation, or error hazardous to persons or property.
- To safely check and correct variations from normal operation after abnormal operation has ended.
- To safely notify responsible operator personnel when notice of an abnormal operation is received.

To review personnel response to check and correct the effectiveness of abnormal operation procedures.

Safety-Related Condition Reporting - Procedures emphasizing safety are included to enable personnel who perform operation and maintenance activities to recognize conditions that may be safety-related conditions subject to the reporting requirements of 191.23.

Procedures are included to report the following conditions using F-191.25:

- Pipe walls corroded too thin for maximum operating pressure;
- Shifting of pipeline caused by environmental effects;
- Any defect or damage affecting serviceability;
- Any malfunction or error increasing pressure above 110% of maximum operating pressure;
- Pipeline leak causing emergency;
- Any condition causing shutdown or a 20% or more reduction in operating pressure.

Surveillance, Emergency Response, and Accident Investigation - The procedures required by 192.613(a), 192.615, and 192.617 must be included.

3.5.9 Emergency Manual Requirements

Section 192.615 requires preparation of an Emergency Manual. This manual must contain written procedures to minimize the hazards resulting from a gas pipeline emergency. It should include procedures for the following purposes:

- To appropriately receive and communicate notices of emergencies.
- To establish and maintain adequate means of communication with appropriate fire, police, and other public officials.
- To take prompt and effective response to the following:
 - Gas detected inside or near a building.
 - Fire located near or directly involving a pipeline facility.
 - Explosion occurring near or directly involving a pipeline facility.
 - Natural disaster.



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- To have necessary resources available as needed at the scene of an emergency.
- To take appropriate actions to protect people first then property.
- To shutdown and reduce pressure in any section of the pipeline system necessary to minimize hazards to life or property.
- To make safe any actual or potential hazard to life or property.
- Safely restoring any service outages.
- To investigate accidents per 192.617.
- To reduce the risk of possible intentional ignition or other hazardous acts.
- To minimize public exposure to injury and probability of accidental ignition.
- To use appropriate instruments to assess the vapor cloud and determine the hazardous areas.
- To hold a post-accident review of employee activities to check and correct procedures used.

3.6 Management of Change (MOC)

Please reference WTG MOC Procedure at westtexasgas.com



4.0 Green House Gas Emissions

4.1 PIPES Act of 2020

The Department of Hazardous Materials Safety Administration issued a new mandate titled “Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020” (PIPES Act of 2020) on December 27, 2020. The rule requires O&M plans to address the elimination of hazardous leaks and minimize the release of natural gas from pipeline facilities. This includes fugitive and vented emissions, the replacement or remediation of pipelines that are known to leak based on the material, design, or past operating and maintenance history of the pipeline, and address public safety and the protection of the environment.

Operators are required to update and implement their O&M plans no later than December 27, 2021.

4.2 West Texas Gas’s Proactive Measures to Reduce Greenhouse Gas Emissions

Prior to the enactment of the PIPES Act of 2020, WTG had previously established the following mitigations measures to address fugitive and vented emissions into the atmosphere. This includes but is not limited to the following

4.2.1 leak survey’s and pipeline repairs for Distribution Systems

WTG conducts leak surveys on the gas distribution systems in intervals which exceed the requirements of CFR §192.723 Distribution Systems: Leakage Surveys, this survey schedule can be found in WTG’s DIMP plan in section 7.2.1.

When possible, WTG squeezes all plastic pipe in order to make necessary repairs. This allows for repairs without the need to blowdown the pipeline.

4.2.2 Thermal imaging surveys of TD stations and all compressor stations

Annually WTG conducts thermal imaging surveys throughout WTG’s operations. The thermal imaging survey includes all transmission compressor stations and rotational bases twenty percent of all transmission-to-distribution (TD) stations. In addition to a thermal imaging camera being used, instrumentation is set up to measure and calculate the amount of gas being released (if any). The data collected from this process is then used to repair or replace the equipment releasing the gas. Found leaks are repaired as fast as operational possible unless the leak is a hazardous leak, then it is repaired immediately.



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4.2.3 Leak Data Collection and Analysis

All known leaks are documented on Form WTG-1101. This includes calculations of fugitive emissions. These leaks are reviewed by the Compliance Department to assess and develop mitigative measures (if any mitigative measures are practical).

4.2.4 Operating WTG's system at a lower pressure than the MAOP

Each segment within the pipeline system has its own MAOP that was determined by using Form F-192.619 MAOP Determination. WTG operates each system as low as operationally possible, not to exceed the segment's MAOP.

4.3 Fugitive and Vented Emissions

Although WTG has put in place mitigations for natural gas emissions, WTG recognizes the need to do more to combat emissions. WTG has established the following additional mitigations to help eliminate hazardous leaks and minimize the release of natural gas from WTG's pipeline facilities.

4.3.1 Regulator Station Inspections

To enhance WTG's annual regulator station inspections (Form WTG-1102) and reduce/eliminate greenhouse gas emissions at regulator stations, a thorough leak survey will be conducted in conjunction with an inspection. The regulator station inspection leak survey includes but not limit to: use of instrument capable of detecting methane leaks, soap testing, visually inspecting, etc. Of the methods to conduct a regulator station inspection leak survey, the preferable method is the use of instrumentation.

4.3.2 Pipeline Leakage Surveys

In specific situations CFR 192.706 Transmission Lines Leakage Surveys allows an operator to use a vegetation survey as an acceptable means to complete a leak survey. Transmission pipelines often cover vast amounts of land, and pipelines can be in locations with minimum to no vegetation present. Taking this concern into consideration, the primary method to conduct leakage surveys is with instrumentation. However, when an instrumentation survey is not practical, a vegetation survey can be used in the event it meets the criteria found in CFR 192.706.

4.3.3 Leak Grading and Repair Schedule

Repairing pipeline leaks is one of the major ways to reduce the amount of fugitive emissions being released into the atmosphere. WTG has a significantly more aggressive repair schedule than the requirements of CFR 192.721. By reducing the required repair times, this will substantially reduce the amount of natural gas being released into the atmosphere. This repair schedule can be found in WTG O&M P-192.706(b).



4.3.4 Pipeline Blowdowns

In order to repair pipelines, test, or make extensions to a pipeline, the pipeline has to be blown down in order to complete these tasks. These blowdowns can range from small to large amounts of natural gas being released into the atmosphere. To reduce the amount of natural gas being released into the atmosphere, when it is practical (in a non-emergency situation), WTG will lower the pressure of the pipeline to an acceptable pressure deemed by a subject matter expert. By lowering the pressure of the pipeline prior to a blowdown, it will dramatically reduce the amount of gas being released into the atmosphere.

At this time, WTG does not utilize flaring when performing blowdowns.

Additionally, while working on a poly system, squeeze off tools are used to minimize the amount of gas released to the atmosphere.

4.3.5 Pneumatic Valve Controllers

Pneumatic valve controllers are widely used in the natural gas industry and are part of normal operations. Consequently, pneumatic devices release or bleed natural gas to the atmosphere and are a major source of methane emissions. When a pneumatic device is at the end of its useful life, WTG will make every attempt to replace any high-bleed devices with a low-bleed model. If possible, the pneumatic valve controller will be replaced with a self-contained device which releases the gas into the pipeline, not the atmosphere.

4.4 Replacement or Remediation of Pipelines

WTG operates transmission and distribution pipelines. The transmission and distribution pipelines will have their own replacement or remediation plan, and they are as follows:

The criteria to define what a leak prone segment of pipeline is defined in WTG's DIMP plan.

4.4.1 Distribution

In 2011, WTG introduced the Gas Distribution Integrity Management Program. This program addresses the replacement or remediation of pipelines that are known to leak based on the material, design, or past operating and maintenance history of the pipeline. The complete program can be found on WTG's website or by contacting WTG's Pipeline Integrity Specialist.

To address the concerning distribution pipelines, the pipelines Lost and Unaccounted for (L&U) gas loss is monitored monthly to identify any abnormal reading. In the event of an unacceptable increased in L&U, an investigation will be conducted. This investigation could include a thorough leak survey if all other possible causes are eliminated. A plan of corrections will be developed and implemented upon approval by senior management.



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4.4.2 Transmission

The majority of WTG' transmission pipelines are coated and protected steel pipe. The remainder of the pipe is either coated but non-protected or non-coated and non-protected steel pipe. Pipeline replacements are handled on a case-by-case basis depending on the pipeline condition severity and leak rate. All replacement projects are at senior management discretion. In addition, to address the concerning transmission pipelines, the pipelines Lost and Unaccounted for (L&U) gas loss is monitored monthly to identify any abnormal reading. In the event of an unacceptable increased in L&U, an investigation will be conducted. This investigation could include a thorough leak survey if all other possible causes are eliminated. A plan of corrections will be developed and implemented upon approval by senior management.

Additionally, WTG has a thorough Transmission Integrity Management Program that reviews / address the replacement or remediation of transmission pipelines that are known to leak based on design, or past operating and maintenance history. The full program can be found on the WTG website or by contacting the Transmission Integrity Specialist.

4.4.3 All Facilities

In the event any individual has an opportunity to reduce the amount of natural gas being release (blow down amount, configuration of pipe/valves, design of system, etc.), contact the district manager. Upon district manager's approval, ensure the compliance department is notified to document the savings.

4.4.3.1 Relief Valves

Relief valve inspection are conducted with an inert gas. WTG is able to test the functionality of the relief valve without having to emit any natural gas to the atmosphere.



5.0 DEFINITIONS

5.1 Definitions of Federally-Used Terms

Term	Definition
Abandoned	Permanently removed from service.
Abnormal operating condition	A condition identified by the operator that may indicate a malfunction of component or deviation from normal operations that may: <ol style="list-style-type: none">1. Indicate a condition exceeding design limits; or2. Result in a hazard(s) to persons, property, or the environment.
Active corrosion	Continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.
Administrator	The Administrator at Pipeline and Hazardous Materials Safety Administration (PHMSA) or their delegate.
Close Interval Survey	A series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.
Component	Any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.
Customer meter	The meter that measures the transfer of gas from an operator to a consumer.
Distribution Center	The initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example: <ol style="list-style-type: none">(1) At a metering location;(2) A pressure reduction location; or(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.
Dry Gas	Gas above its dew point and without condensed liquids.
Electrical survey	A series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.



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Term	Definition
Evaluation	<p>A process established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:</p> <ul style="list-style-type: none"> • Written examination; • Oral examination; • Work performance history review; • Observation during; • Performance on the job; • On the job training; • Simulations; and/or • Other forms of assessment.
Flammable gas	<p>Any material that is a gas at 20 °C (68 °F) or less and 101.3 kPa (14.7 psig) of pressure (a material which has a boiling point of 20 °C (68 °F) or less at 101.3 kPa (14.7 psig)) that:</p> <ol style="list-style-type: none"> 1. Is ignitable at 101.3 kPa (14.7 psig) when in a mixture of 13 percent or less by volume with air; or 2. Has a flammable range at 101.3 kPa (14.7 psig) with air of at least 12 percent regardless of the lower limit.
Gas	Natural gas, flammable gas, or gas that is toxic or corrosive.
Gathering line	A pipeline that transports gas from a current production facility to a transmission line or main.
Hard Spot	An area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV ₁₀).
Incident	<p>Any of the following events:</p> <p>(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSA), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:</p> <ul style="list-style-type: none"> (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of \$145,400 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191. (iii) Unintentional estimated gas loss of three million cubic feet or more. <p>(2) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) of this definition.</p>
In-line Inspection (ILI)	An inspection of a pipeline from the interior of the pipe using an inspection tool also called <i>intelligent</i> or <i>smart pigging</i> . This definition includes tethered and self-propelled inspection tools.



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Term	Definition
In-line Inspection Tool	An instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an <i>intelligent</i> or <i>smart pig</i> .
Intrastate pipeline	A pipeline or part of a pipeline to which this part applies that is not an interstate pipeline.
Line section	A continuous run of transmission line between: <ul style="list-style-type: none"> • Adjacent compressor stations; • A compressor station and storage facilities; • A compressor station and a block valve; or • Adjacent block valves.
Listed specification	A specification listed in Appendix B, Section I of Part 192.
Maximum Actual Operating Pressure	The maximum pressure that occurs during normal operations over a period of one (1) year.
Maximum Allowable Operating Pressure (MAOP)	The maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.
Municipality	A city, county or any other political subdivision of a state.
Nominal wall thickness	The wall thickness listed in the pipe specifications.
Operator	A person who engages in the transportation of gas.
Person	Any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.
Pipeline or pipeline system	All parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.
Pipe or line pipe	Any pipe or tubing used in the transportation of gas, including pipe-type holders.
Pipeline environment	Includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.
Pipeline facility	New and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.
Qualified	Applies to an individual who has been evaluated and can: <ol style="list-style-type: none"> 1. Perform assigned covered tasks; and 2. Recognize and react to abnormal operating conditions.
Rural area	Outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.



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Term	Definition
Specified Minimum Yield Strength (SMYS)	<ol style="list-style-type: none">1. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or2. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).
State	Each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico.
Stress level	The level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.
Toxic product	"Poisonous material" as defined by §173.132, Class 6, Division 6.1B: Definitions of this Chapter.
Transportation of gas	The gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.
Wrinkle Bend	<p>A bend in the pipe that:</p> <p>(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:</p> <p>(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or</p> <p>(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.</p> <p>(2) (i) If the length of the wrinkle bend cannot be reliably determined, then wrinkle bend means a bend in the pipe where $(h/D)*100$ exceeds 2 when S is less than 37,000 psi (255 MPa), where $(h/D)*100$ exceeds for psi [for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where $(h/D)*100$ exceeds 1 when S is 47,000 psi (324 MPa) or more.</p> <p>(ii) Where:</p> <p>(A) D = Outside diameter of the pipe, in. (mm);</p> <p>(B) h = Crest-to-trough height of the ripple, in. (mm); and</p> <p>(C) S = Maximum operating hoop stress, psi (S/145, MPa).</p>

5.2 Definitions of New Mexico Specific Terms

Term	Definition
Access information	A telephone number, a fax number, an email address, and if available a website.
Applicable laws	The Hazardous Liquid Pipeline Safety Act, 49 USC Sections 2001 et seq; the Hazardous Materials Transportation Act, 49 USC Sections 1801 et seq; the Natural Gas Pipeline Safety Act, 49 USC Sections 60101 et seq; Chapter 62, Article 14 NMSA 1978; the Pipeline Safety Act, Sections 70-3-11 to 70-3-20 NMSA 1978; these rules, and commission orders issued pursuant to them.



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Term	Definition
Bid locate	The marking of underground facilities at the request of a project owner for the purpose of providing information to persons bidding on a project.
Design locate	The marking of underground facilities at the request of a project owner for the purpose of providing information to persons designing a project.
Director	The Director of the Transportation Division of the New Mexico Public Regulation Commission or their designee.
Excavation locate	The marking of underground facilities at the request of an excavator for the purpose of providing information to an excavator working on a project.
Holiday	The day New Mexico state government observes New Year's Day, Martin Luther King Jr. Birthday, Memorial Day, Independence Day, Labor Day, Columbus Day, Veteran's Day, Thanksgiving Day, President's Day, and Christmas Day.
Non-member UFO	A UFO that is not a member of a one-call system
Project owner	The owner of a project involving excavation or the person designated by the owner to be in charge of the project involving excavation.
Road maintenance	Routine grading and resurfacing of the earth and gravel surface, but not the subbase of a roadway for the purpose of maintaining the surface condition of the road and includes recovery of material from a borrow ditch but does not include road construction or reconstruction and shall entail moving no more than 4 inches of earth, road maintenance does not include street sweeping or road milling and resurfacing as long as the subsurface is not disturbed.
Staff	The staff of the Pipeline Safety Bureau of the Transportation Division of the Public Regulation Commission.
These rules	Title 18, Chapter 60.
Underground Facility Operator (UFO)	A person who operates an underground facility
Working Day	A twenty-four hour period excluding weekends and holidays.

5.3 Definitions of Oklahoma Specific Terms

Term	Definition
Atmospheric corrosion	Aboveground corrosion caused by chemical or electrochemical reaction between pipe materials, usually a metal, and its environment, that produces a deterioration of the material.
Commission	The Oklahoma Corporation Commission.
Corrosive gas	Gas that, by chemical reaction with the pipe to which it is exposed, usually metal, produces a deterioration of the material.
Delivery point(s)	The point where the possession or control of the gas stream transfers from a shipper to a gatherer.



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Term	Definition
Gatherer	Any person who performs the activities or processes defined as gathering.
Gathering	<ol style="list-style-type: none"> 1. The transportation of natural gas through a pipeline for hire, compensation or otherwise; or 2. Transporting natural gas through a pipeline, in whole or in part, for such person's own account, whether in connection with: <ol style="list-style-type: none"> a. The purchase and resale of natural gas; or b. The processing of natural gas or otherwise. <p>Performed by a person other than a local distribution company, intrastate transmission pipeline or interstate pipeline.</p> <p>Gathering includes activities or processes performed between the delivery points and the redelivery points, which shall include and be limited to:</p> <ul style="list-style-type: none"> • Transportation; • Measurement; • Conditioning; • Compressing; • Pressure regulation; • Recompressing; and • Cleaning and treating (processes of separation, dehydration, removal of all contaminants and inerts and filtering). <p>Gathering specifically shall not include processing or the extraction of natural gas liquids and products.</p>
Legal staff	The Office of General Counsel of the Commission.
Manager of Pipeline Safety	The Manager of the Pipeline Safety Department of the Commission.
Master meter system	A pipeline system for distributing gas within, but not limited to, a definable area such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as rents.
Person	Any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.
Pipeline or pipeline system	All parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.
Pipeline Safety Department	The Department of Pipeline Safety for the Commission.



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Term	Definition
Redelivery point(s)	The point at which the gatherer relinquishes possession or control of the gas stream.
Residential customer meter	The meter that measures the transfer of gas from an operator to a residential customer.
Secretary	The custodian of official records of the Commission.
Shipper	Any person who owns or controls natural gas that seeks or receives gathering service from a gatherer.
Similarly situated shipper	Any person so designated by the Commission, after application and hearing, wherein the Commission determines that such applicant should receive the benefits and obligations specified in a previously issued Commission order under this act. In determining whether a person is a similarly situated shipper, the Commission shall consider all relevant conditions and factors including those utilized in fixing the fee or terms and conditions of service in the previous order. Similarly situated shipper status shall be limited to applicant's interest in the well(s) covered by the previous order.
Spread fee	The monthly difference obtained by subtracting the value received by the gatherer for the natural gas liquids attributable to shipper from the value of the heating content of the natural gas converted to natural gas liquids attributable to the shipper, established by the cost of natural gas purchased by the gatherer to specifically replace such heating content or, if no actual purchases were made, by the value received by gatherer for natural gas sold at the plant tailgate; provided, however, in any month that the result of this calculation generates a value of zero or less, there shall be deemed to be no spread fee.
State	The State of Oklahoma and all lands within its boundaries.
Terms and Conditions of Service (TCOS)	Includes all factors defining the obligations between the gatherer and shipper respecting any gathering activities or process, including, but not limited to, nominations, deductions for fuel, accounting for imbalances, imbalance penalties, assessments, charges or makeup provisions, costs, charges and fees for connection or maintaining connections, duration of gathering service, location of receipt and delivery points, quality specifications of natural gas, minimum and maximum pressures, and measurement.
Transportation of gas	The gathering, transmission, or distribution of gas by pipeline or its storage.



Gas Operations and Maintenance Manual

5.4 Definitions of Texas Specific Terms

Term	Definition
Affected person	<p>This definition of this term applies only to the procedures and requirements of §8.125 of this title (relating to Waiver Procedure). The term includes but is not limited to:</p> <ol style="list-style-type: none">1. Persons owning or occupying real property within 500 feet of any property line of the site for the facility or operation for which the waiver is sought;2. The city council, as represented by the city attorney, the city secretary, the city manager, or the mayor, if the property that is the site of the facility or operation for which the waiver is sought is located wholly or partly within any incorporated municipal boundaries, including the extraterritorial jurisdiction of any incorporated municipality. If the site of the facility or operation for which the waiver is sought is located within more than one incorporated municipality, then the city council of every incorporated municipality within which the site is located is an affected person;3. The county commission, as represented by the county clerk, if the property that is the site of the facility or operation for which the waiver is sought is located wholly or partly outside the boundary of any incorporated municipality. If the site of the facility or operation for which the waiver is sought is located within more than one county, then the county commission of every county within which the site is located is an affected person; and4. Any other person who would be impacted by the waiver sought.
Applicant	<p>A person who has filed with the Safety Division a complete application for a waiver to a pipeline safety rule or regulation, or a request to use direct assessment or other technology or assessment methodology not specifically listed in §8.101(b)(1), of this title (relating to Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines).</p>
Application for waiver	<p>The written request, including all reasons and all appropriate documentation, for the waiver of a particular rule or regulation with respect to a specific facility or operation.</p>
Charter school	<p>An elementary or secondary school operated by an entity created pursuant to Texas Education Code, Chapter 12.</p>
Commission	<p>The Railroad Commission of Texas.</p>



Gas Operations and Maintenance Manual

Term	Definition
Direct assessment	A structured process that identifies locations where a pipeline may be physically examined to provide assessment of pipeline integrity. The process includes collection, analysis, assessment, and integration of data, including but not limited to the items listed in §8.101(b)(1) of this title, relating to Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines. The physical examination may include coating examination and other applicable non-destructive evaluation.
Director	Director of the Safety Division, or the Director's delegate.
Division	The Safety Division of the Commission.
Farm tap odorizer	A wick-type odorizer serving a consumer or consumers off any pipeline other than that classified as distribution as defined in 49 CFR 192.3 which uses not more than 10 mcf on an average day in any month.
Gas	Natural gas, flammable gas, or other gas that is toxic or corrosive.
Gas company	Any person who owns or operates pipeline facilities used for the transportation or distribution of gas, including master metered systems.
In-line inspection	An internal inspection by a tool capable of detecting anomalies in pipeline walls such as corrosion, metal loss, or deformation.
Intrastate pipeline facilities	Pipeline facilities located within the State of Texas that are not used for the transportation of natural gas or hazardous liquids or carbon dioxide in interstate or foreign commerce.
Lease user	A consumer who receives free gas in a contractual agreement with a pipeline operator or producer.
Master meter operator	The owner, operator, or manager of a master metered system.
Master metered system	A pipeline system (other than one designated as a local distribution system) for distributing natural gas within but not limited to a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means such as rents.
Natural gas supplier	The entity selling and delivering the natural gas to a school facility or a master metered system. If more than one entity sells and delivers natural gas to a school facility or master metered system, each entity is a natural gas supplier for purposes of this chapter.
Operator	A person who operates on his or her own behalf, or as an agent designated by the owner, intrastate pipeline facilities.



Gas Operations and Maintenance Manual

Term	Definition
Person	Any individual, firm, joint venture, partnership, corporation, association, cooperative association, joint stock association, trust, or any other business entity, including any trustee, receiver, assignee, or personal representative thereof, a state agency or institution, a county, a municipality, or school district or any other governmental subdivision of this state.
Person responsible for a school facility	In the case of a public school, the superintendent of the school district as defined in Texas Education Code, §11.201, or the superintendent's designee previously specified in writing to the natural gas supplier. In the case of charter and private schools, the principal of the school or the principal's designee previously specified in writing to the natural gas supplier.
Pipeline facilities	New and existing pipe, right-of-way, and any equipment, facility, or building used or intended for use in the transportation of gas or hazardous liquid or their treatment during the course of transportation.
Pressure test	Those techniques and methodologies prescribed for leak-test and strength-test requirements for pipelines. For natural gas pipelines, the requirements are found in 49 Code of Federal Regulations (CFR) Part 192, and specifically include 49 CFR 192.505, 192.507, 192.515, and 192.517.
Private school	An elementary or secondary school operated by an entity accredited by the Texas Private School Accreditation Commission.
Public school	An elementary or secondary school operated by an entity created in accordance with the laws of the State of Texas and accredited by the Texas Education Agency pursuant to Texas Education Code, Chapter 39, Subchapter D. The term does not include programs and facilities under the jurisdiction of the Texas Department of Mental Health and Mental Retardation, the Texas Youth Commission, the Texas Department of Human Services, the Texas Department of Criminal Justice or any probation agency, the Texas School for the Blind and Visually Impaired, the Texas School for the Deaf and Regional Day Schools for the Deaf, the Texas Academy of Mathematics & Science, the Texas Academy of Leadership in the Humanities, and home schools or proprietary schools as defined in Texas Education Code, §132.001.
School facility	All piping, buildings and structures operated by a public, charter, or private school that are downstream of a meter measuring natural gas service in which students receive instruction or participate in school sponsored extracurricular activities, excluding maintenance or bus facilities, administrative offices, and similar facilities not regularly utilized by students.
Segment	A section of pipe that has like attributes on the same system.



Gas Operations and Maintenance Manual

Term	Definition
Transportation of gas	The gathering, transmission, or distribution of gas by pipeline or its storage within the State of Texas. For purposes of safety regulation, the term shall include onshore pipeline and production facilities, beginning after the first point of measurement and ending as defined by 49 CFR Part 192 as the beginning of an onshore gathering line.
Transportation of hazardous liquids or carbon dioxide	The movement of hazardous liquids or carbon dioxide by pipeline, or their storage incidental to movement, except that, for purposes of safety regulations, it does not include any such movement through gathering lines in rural locations or production, refining, or manufacturing facilities or storage or in-plant piping systems associated with any of those facilities.



Purpose

The purpose of this Management of Change (MOC) process is to ensure a consistent and documented process for notification of any improvements or significant changes.

Responsibility

All Employees: To understand their operational area and the necessity of improvements or significant changes as defined below. Document these suggestions and provide them to their immediate supervisor for review and approval.

Immediate Supervisor: Review all MOC suggested improvements and evaluate for need. If benefit is gained, forward to the Compliance Department for review and completion process. Once they receive notification of a MOC change, the supervisor will notify their employees of the change. This notification will be documented on WTG-Attendance form or equivalent and stored at the local field office.

Compliance Department: Document MOC requests in the MOC log. Review process to determine that the request is needed, complies with all gas pipeline regulations, is beneficial company-wide, and makes good business sense. If the compliance department deems change necessary, the MOC will be forwarded to senior management for final approval. If senior management approves, the final changes will be implemented by WTG. If denied, the denial reason will be added to the MOC log. All MOC requests will be documented on F-192.605(a) and provided to personnel making initial request. The approved and denied changes will be communicated to all immediate supervisors via email. Documents will be updated on the web, if required. If applicable, notification will be made to federal and state regulatory agencies of such significant changes by the Compliance Department.

VP of Operations, Associate VP of Operations, North Director, South Director, Technical Field Operations Director, Compliance Director: During the Senior Management monthly staff meeting All requests will be reviewed and provide status of approval or denial to Compliance Department.

Determination Process

Low Impact Changes — These changes require informal communication such as an email to the affected employee or districts. These may include, but are not limited to, minor wording changes / corrections, changes in procedure or form numbers, field personnel changes, minor administrative program changes, etc. No additional approval is needed to complete these changes and may not be documented in the MOC log.



Significant Changes — These changes can include technical, design, physical, environmental, operational, procedural, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. These requests must be documented and followed as defined in the responsibility section above.

In the event a significant change is required to a transmission pipeline, WTG will evaluate and mitigate, as necessary, any potential risk to safety or the environment through the MOC process. Request will be made on WTG PO-MOC Request Form or equivalent. The documentation required for this change will include the following.

- Reason for change
- Authority for approving changes
- Analysis of implications
- Acquisition of required work permits (if applicable)
- Documentation
- Communication of change to affected parties
- Time limitations (if applicable)
- Qualification of staff



Description	This procedure is used to report incidents on transmission, gathering and distribution lines to the Federal Pipeline and Hazardous Material Safety Administration (PHMSA) through the NCR and any relevant state agency.
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Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
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This following pipelines are not included-

- Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;
- Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9.
- Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or
- Onshore gathering of gas outside of the following areas:
 - An area within the limits of any incorporated or unincorporated city, town, or village.
 - Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.



- Frequency**
- Telephone Notice: As soon as practical after a reportable incident
- Within 1 hour to PHMSA and a follow-up within 48 hours to confirm or update any initial information
 - Within 1 hour to all appropriate state agencies

Electronic Follow-up on PHMSA website forms: Original submittal as soon as practical but no more than 30 days after a reportable incident. Report must be finalized once information and data is found to be correct. Initial, supplemental and final reports must be emailed to applicable state agency.

- Reference**
- 49 CFR 191.5 *Telephonic Notice of Certain Incidents*
- 49 CFR 191.9 *Distribution System: Incident Report*
- 49 CFR 191.15 *Transmission and Gathering Systems: Incident Report*
- 16 TAC Rule 8.210(a) *Accident, Leak or Incident Report*
- 165 OAC Chapter 20-5-11 *Telephonic Notice of Certain Incidents*
- 165 OAC Chapter 20-5-12 *Addresses for Written Reports*
- 165 OAC Chapter 20-3-13 *Distribution system reporting requirements*
- 165 OAC Chapter 20-5-14 *Transmission and gathering systems reporting requirements.*
- New Mexico – 18.60.2.8(B)(1) *Adoption of Portions of the Code of Federal Regulations*
-

- Forms /
Record
Retention**
- F-191.1 Incident Notification, Reporting & Investigation or equivalent data (Transmission) / *Life of Pipeline System*
- F-191.9 Incident Notification, Reporting & Investigation or equivalent data (Distribution) / *Life of Pipeline System*
- PHMSA Form F 7100.1 *Incident Report for Gas Distribution Systems*



*(on PHMSA website)/ Life of Pipeline
System*

PHMSA Form F 7100.2 *Incident Report for Gas Transmission and
Gathering Systems(on PHMSA website)/
Life of Pipeline System*

**Related
Specifications**

None

**OQ Covered
Task**

None



Procedure Steps

1. Receive notice of potential incident, mechanical fitting failure or safety-related condition. (This notice may come from West Texas Gas personnel or from someone outside the company.)
2. Complete Initial Notification section of appropriate Form F-191.1 or F-191.9 or equivalent.
3. Immediately initiate emergency plan.
4. Determine if the situation is a reportable *incident*.
 - An INCIDENT reportable to PHSMA and applicable state agency:
 - An event that involves a release of gas from a pipeline AND
 - A death, or personal injury necessitating in-patient hospitalization;
 - OR
 - Estimated property damage of \$145,400 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
 - OR
 - Unintentional estimated gas loss of three million cubic feet or more.
 - An event that results in an emergency shutdown,
 - An event that is significant in the judgment of the operator, even though it did not meet the criteria above.
5. If the event does not constitute an Incident, refer to Procedure P-191.23 to determine if it is a safety-related condition.
6. If the incident requires a telephonic report (See table on page 6) call the National Response Center (NRC) at 800-424-8802 and applicable states **AT THE EARLIEST PRACTICAL MOMENT**, or within one (1) hour of incident, and document those calls on appropriate form.

NOTE: If you are not sure as to whether it is a reportable incident, notify your supervisor for direction.

- District/Division Managers: If it is thought that a probable incident has occurred, call VP of Operations immediately and inform him of the probable incident. If the VP of Operations is not available, then call the Compliance Manager. These individuals will decide if the incident is reportable and who will make the notification.



7. Gather data as it becomes available and record it on appropriate form for use in the Root Cause Analysis and to determine if procedures were adequate for handling the incident.
8. Within 30 days of the incident, compliance department will complete PHMSA Form F 7100.1 Gas Distribution or Form F 7100.2 Gas Transmission and Gathering and submit to WTG VP of Operations for approval. This form must be submitted electronically to PHMSA at <http://portal.phmsa.dot.gov/>, and emailed to the applicable state within 30 days of the incident.
9. As additional information becomes available, update PHMSA forms and submit supplemental reports (within 30 days of availability) to PHMSA and the applicable state.
10. All PHMSA forms must be marked as finalized once information and data is found to be correct.
11. Retain incident records and reports on file for the life of the facility.



Telephonic Reports

File a report if incident meets criteria below:

Event	Notification			
Involves a release of a gas <u>and</u> :	PHMSA	RRC	OK	NM
Caused a death or a personal injury requiring hospitalization	Yes	Yes	Yes	Yes
Estimated property damage of \$145,400 or more (excluding cost of gas lost)	Yes	Yes	Yes	Yes
Unintentional estimated gas loss of three million cubic feet or more	Yes	Yes	Yes	Yes
Judged significant due to location or other reason	Yes	Yes	Yes	Yes

The necessary telephonic reports will include the following:

- Names of operator and person making report and their telephone numbers.
- The location of the incident.
- The time of the incident.
- The number of fatalities and personal injuries, if any.
- All other significant facts that are known by the operator or are relevant to the cause of the incident or extent of the damages.
- In the state of Texas also include:
 - Telephone number of on-site person
 - Estimated property damage, gas lost
 - Media involved
 - Was there an explosion or fire
 - Did it require traffic to be rerouted or an evacuation

Telephonic reports will be made by calling the following numbers:

- Federal PHMSA: Call 1-800-424-8802
- Texas RRC: 512-463-6788 or 844-773-0305
- OK (OCC) 1-405-521-2258
- NM 1-505-490-2375



Description

This procedure is used to report total mileage, number of reportable incidents and leaks eliminated, or repairs on transmission, gathering and distribution lines to the Federal Pipeline and Hazardous Material Safety Administration (PHMSA) and any relevant State agency. Prior to reporting ensure all companies under plan have PHMSA OPID assigned and appropriate state organization numbers.

**Regulatory
Applicability**

- ☒ Regulated Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☒ Regulated Gathering Pipelines (Type B)
- ☒ Regulated Distribution Pipelines

This following pipelines are not included-

- Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;
- Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9.
- Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or
- Onshore gathering of gas outside of the following areas:
 - An area within the limits of any incorporated or unincorporated city, town, or village.
 - Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

Frequency

Annual; no later than March 15th.



Reference	49 CFR 191.11	Distribution System: Annual Report
	49 CFR 191.17	Transmission and Gathering Systems: Annual Report
	16TAC Rule 8.210(b)	Pipeline Safety Annual Report
	LA Title 43 Part XIII 311	Distribution System: Annual Report
	LA Title 43 Part XIII 317	Transmission and Gathering Systems: Annual Report
	165 OAC Chapter 20-5-13	Distribution system reporting requirements.
	165 OAC Chapter 20-5-14	Transmission and gathering systems reporting requirements.
<hr/>		
Forms / Record Retention	F-191.17	Transmission and Gathering Systems: Annual Report / 5 Years
	F-191.11	Annual Report (Distribution) / 5 Years
<hr/>		
Related Specifications	None	
<hr/>		
OQ Covered Task	None	



Procedure Steps

Compliance department is responsible for:

1. Determine if there have been any mileage changes (refer to procedures P-192.5 and P-192.8), reportable incidents, leaks or repairs since last year.
2. Complete PHMSA Form 7100.1-1 "Annual Report for Gas Distribution Systems" (Form F-191.11) and / or PHMSA Form 7100.2-1 "Annual Report for Gas Transmission and Gathering Systems" by March 15th, for the preceding calendar year and submit electronically.

Submit the form electronically at this address and email copy to applicable state agency:

<http://portal.phmsa.dot.gov/>

Retain a copy in DOT files for at least five years.

NPMS Submittal

1. Examine pipeline data and determine if any part of the submission (geospatial, attribute, metadata, or public contact information) has changed in the previous year.
2. If any of these components have changed, resubmit the data to the NPMS concurrently with the Annual Report.

Note: The NPMS prefers that operators resubmit the entire pipeline system with the exception of previously abandoned lines. Do not resubmit lines already abandoned in the NPMS. If you are unsure of which lines are already in the NPMS as abandoned for your company please contact NPMS Staff at npms-nr@mbakercorp.com. Operator ID numbers and contact information for the submission must be included.

Attribute data and metadata must be revised according to the new guidelines or submittals will be rejected. Changes include a more detailed product description and more specific codes for pipeline changes. See [NPMS Operator Standards Manual](#) for information on submittal guidelines.

Abandoned pipelines should only be submitted to NPMS once. Following the first submittal, abandoned pipelines should be removed from all subsequent submittals. If a pipeline has already been submitted as abandoned, it should be removed from the data before the next annual submittal.

3. Ensure Operator ID numbers (internal DOT numbers assigned by PHMSA to the operator for specific assets) in annual report submissions match the same assets described in NPMS submissions unless there is only one Operator ID number for all assets.
4. If there is no change since the previous NPMS submission, send an email to npms-nr@mbakercorp.com or use the "Update your submission online" tool on the NPMS Web site (<http://www.npms.phmsa.dot.gov>) in lieu of making a submission.
5. The data submittals will be accompanied by a transmittal letter adhering to the following format:



Follow the Making a Submission link at www.npms.phmsa.dot.gov to download the Cover/Transmittal Letter template, or compile a letter including the following three items:

1. Contact information for the person National Repository Staff should contact with any questions.
2. A brief description of the system changes reflected in the submission (e.g., sold, acquired, re-routed, abandoned lines, etc. since the previous submission).
3. Use one of the codes below to indicate how this submission as a whole should affect the previously submitted data for this OPID. You can read more about these submission types in section 2.2 of the [NPMS Operator Standards Manual](#).
 - INI: This is the initial submission to the NPMS for this OPID
 - ADD: This submission should be added to the data currently in the NPMS for this OPID (Addition)
 - FRP: This submission should replace all data currently in the NPMS for this OPID (Full Replacement)
 - PRP: This submission should replace specific segments currently in the NPMS for this OPID as indicated by the assigned Pipeline IDs (Partial Replacement)
 - DEL: This submission only indicates which segments should be removed from the data currently in the NPMS for this OPID (Deletion)



Description	<p>This procedure is used to report safety-related conditions to the Federal Pipeline and Hazardous Material Safety Administration (PHMSA) and any relevant State agency.</p>
Regulatory Applicability	<div><div><input checked="" type="checkbox"/> Regulated Transmission Pipelines</div><div><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A)</div><div><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B)</div><div><input checked="" type="checkbox"/> Regulated Distribution Pipelines</div><div><input type="checkbox"/> Regulated LNG Facilities</div></div> <p>This following pipelines are not included-</p> <ul style="list-style-type: none">• Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;• Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9.• Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or• Onshore gathering of gas outside of the following areas:<ul style="list-style-type: none">○ An area within the limits of any incorporated or unincorporated city, town, or village.○ Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.
Frequency	<p>As needed (Within 5 working days after determining the condition is safety-related, but not more than 10 days after discovering the condition—see “Time to Report” section of this procedure.)</p>



Reference	49 CFR 191.23 49 CFR 191.25 49 CFR 192.605(d) TAC 16 8.210(c) LA Title 43 Part XIII 323 LA Title 43 Part XII 325 LA Title 43 Part XIII 2705(d)	<i>Reporting Safety-Related Conditions</i> <i>Filing Safety-Related Condition Reports</i> <i>Operations and Maintenance Manual</i> <i>Safety-related Condition Reports</i> <i>Reporting Safety-Related Conditions</i> <i>Filing Safety-Related Condition Reports</i> <i>Operations and Maintenance Manual</i>
<hr/>		
Forms / Record Retention	F-191.25	<i>Safety-Related Conditions / Life of Pipeline System</i>
<hr/>		
Related Specifications	None	
<hr/>		
OQ Covered Task	None	



Procedure Steps

1. Receive notice of potential Safety-Related Condition. (This notice may come from company personnel or from someone outside the company.)

District/Division Managers: If you think you have a possible Safety Related Condition, inform the WTG Operations Manager or if you can not reach him inform the WTG VP Natural Gas. They will help you make the determination and file the proper form.

NOTE: If it has not been determined that the condition is NOT a reportable Incident, refer to procedure P-191.5 to make this determination.

2. Use the flowchart on page 4 to determine if the condition is a Safety-Related Condition. This must be done within 10 days of discovery or the condition must be reported.
3. If the condition is a Safety-Related Condition, determine if it is reportable using the flowchart on page 5 of this procedure.

NOTE: This must be determined within 5 days of determining the condition is a safety-related Condition or within 10 days of discovery.

4. If the condition is a reportable Safety-Related Condition, complete form F-191.25.
5. Fax the completed form to PHMSA at (202) 366-7128 and relevant state agency.

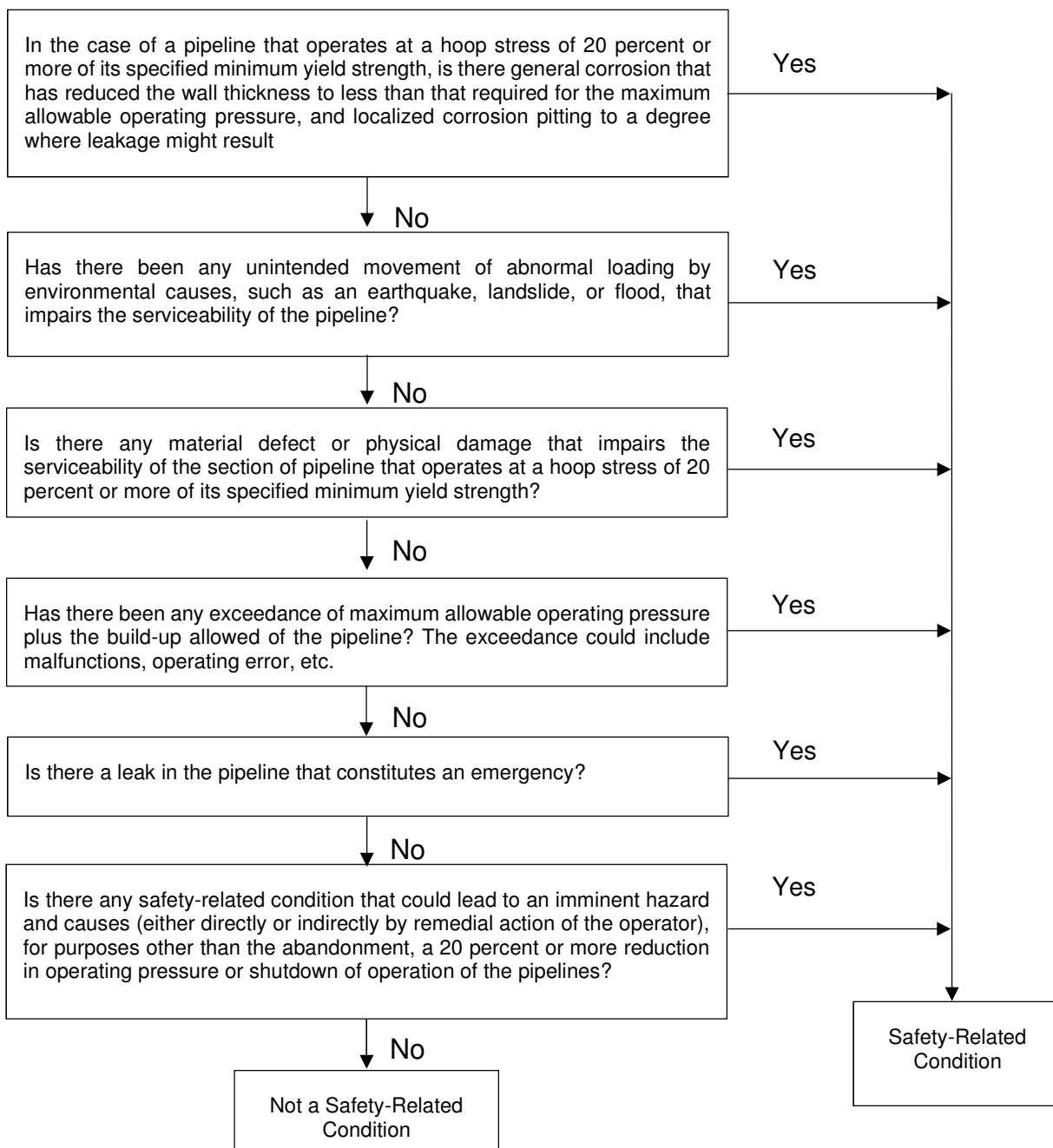
NOTE: In Texas, fax the completed form to TRRC at (512) 463-7319 or mail to railroad Commission, Safety Division, PO Box 12967, Austin, Texas 78711.

Agency	Fax	Mail
Pipeline and Hazardous Materials Safety Administration (PHMSA)	(800) 424-8802	Electronic
Texas	(512) 463 - 7319	Railroad Commission Safety Division PO Box 12967 Austin, Texas 78711
Louisiana	(225) 342-5505	Commissioner of Conservation P.O. Box 94275 Baton Rouge, LA 70804-9275
Oklahoma	(405) 522-3455	Oklahoma Corporation Commission P.O. Box 52000 Oklahoma City, OK 73152-2000
New Mexico	(505) 827-3767	604 W. San Mateo Suite B, Upper Level Santa Fe NM 87505
Kansas	(202) 366-7128	Kansas Corporation Commission 1500 SW Arrowhead Rd Topeka, KS 66604-4027

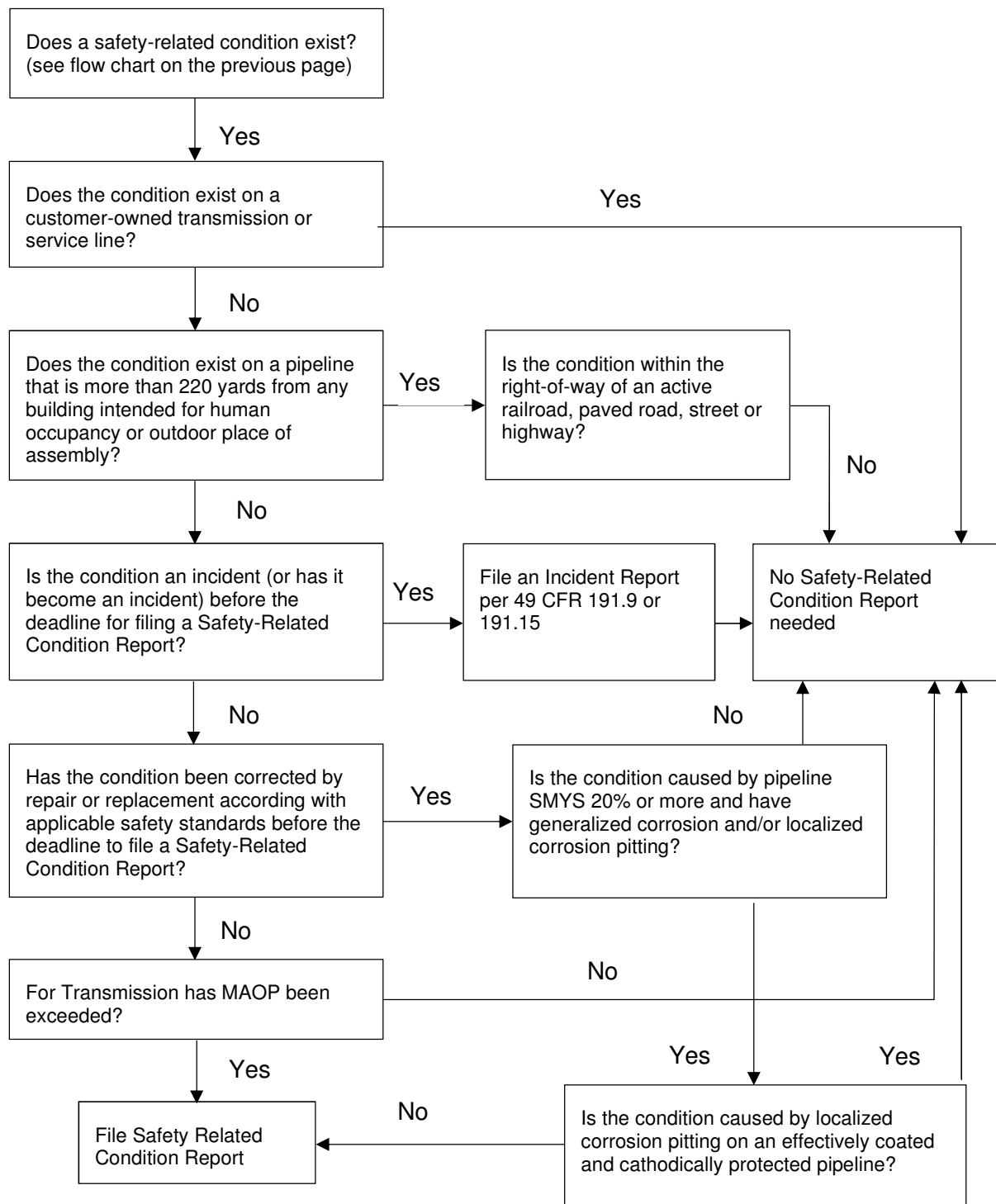
6. Retain copies of the form in the DOT file for the life of the pipeline.



IDENTIFYING A SAFETY-RELATED CONDITION



REPORTING A SAFETY RELATED CONDITION

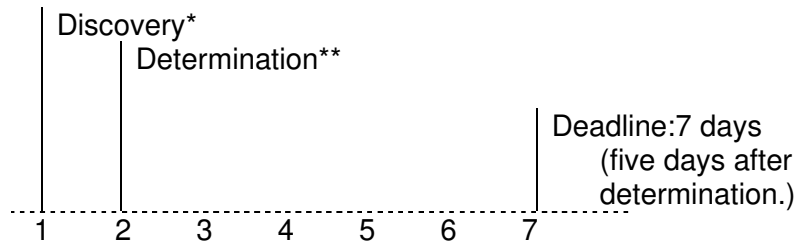
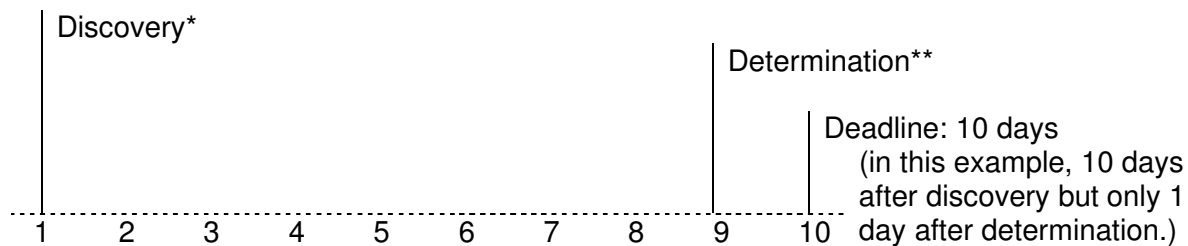




Time to Report (Reporting Deadlines)

Use the following timelines as examples to determine the deadline for reporting the safety-related condition. A safety-related condition must be reported within 10 days of discovering a potential safety-related condition or five days after determining it as a safety-related condition, whichever is sooner. Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in §191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

Examples:



*Discovery of a potential Safety-Related Condition

**Determination that a Safety-Related Condition Exists

Reporting Methods

Reports must be filed by email to InformationResourcesManager@dot.gov or by facsimile to (202) 366-7128. For a report made pursuant to §191.23(a)(1) through (9), the report must be headed "Safety-Related Condition Report." For a report made pursuant to §191.23(a)(10), the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:

- (1) Name, principal address, and operator identification number (OPID) of the operator.



- (2) Date of report.
- (3) Name, job title, and business telephone number of person submitting the report.
- (4) Name, job title, and business telephone number of person who determined that the condition exists.
- (5) Date condition was discovered and date condition was first determined to exist.
- (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
- (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
- (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.



Description	The purpose of this procedure is to establish a pipeline's class locations and its boundaries.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Unregulated Gathering <input type="checkbox"/> Distribution Pipelines	
Frequency	Upon construction and as needed thereafter due to changes in population density surrounding the pipeline as indicated by the continuing surveillance program and not to exceed two calendar years.	
Reference	49 CFR 192.5 <i>Class Locations</i> 49 CFR 192.609 <i>Change in Class Location: Required Study</i> 49 CFR 192.611 <i>Change in Class Location: Confirmation of Maximum Operating Pressure.</i> LA Title 43 Part XIII 2705 <i>Class Locations</i> LA Title 43 Part XIII 2709 <i>Change in Class Location: Required Study</i> LA Title 43 Part XIII 2711 <i>Change in Class Location: Confirmation of Maximum Operating Pressure.</i> 49 CFR 192.613 <i>Continuing Surveillance</i>	
Forms / Record Retention	F-192.5	<i>Class Location Survey / 2 years or until next review whichever is longer</i>
	F-192.619	<i>MAOP Determination / Life of Pipeline System</i>
Related Specifications	None	
OQ Covered Task	None	



Procedure Steps

1. Utilize previous class location(s) forms and imagery of the potentially affected segment(s). Use the attached diagrams to determine class location. Final determination of actual class location of each pipeline or pipeline segment is cooperative effort of the compliance department and district management. Electronic imagery will be reviewed annually and physical inspections will be done bi-annually.
2. Survey the area(s) to determine the current class location(s). Document the new class location on form F-192.5 or equivalent.
3. In the event of a class location change (increase), the following procedures are required:
 - a) If the pipe hoop stress is not commensurate with the current class location or if the segment operates above 40% of SMYS, obtain additional information as described in 49 CFR 192.609 including:
 - i) Present class location
 - ii) Design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location;
 - iii) The physical condition of the segment to the extent it can be ascertained from available records;
 - iv) The operating and maintenance history of the segment;
 - v) The MAOP and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
 - vi) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.
4. Determine if the pipe MAOP and corresponding pipe hoop stress is acceptable for the current class location. Refer to procedure P-192.619.
5. If the hoop stress corresponding to the established MAOP of the segment does not commensurate with the present class location, but the segment is in satisfactory condition, the MAOP will be confirmed or revised as follows:
 - a) If the segment has been previously tested in place for at least 8 hours, the MAOP is the pressure obtained by multiplying the test pressure by the following factors:
 - i) 0.8 in Class 2 locations,
 - ii) 0.667 in Class 3 locations
 - iii) 0.555 in Class 4 locations.

Note the hoop stress cannot exceed”

 - 72% of SMYS in Class 2 locations
 - 60% of SMYS in Class 3 locations; or
 - 50% of SMYS in Class 4 locations.



- b) Reduce the MAOP so that the hoop stress is not more than that allowed for new segments of pipelines in the class location
- c) Test the segment involved in accordance with 49 CFR Subpart J; and establish the MAOP according to the following material:
 - i) Multiply the test pressure times the following factors:
 - (1) 0.8 in Class 2 locations,
 - (2) 0.667 in Class 3 locations
 - (3) 0.555 in Class 4 locations.
 - ii) The hoop stress may not exceed:
 - (1) 72% of SMYS in Class 2 locations
 - (2) 60% of SMYS in Class 3 locations; or
 - (3) 50% of SMYS in Class 4 locations.

NOTE: The confirmed or revised MAOP, may not exceed the previous MAOP.

NOTE: 24 months are available to make revisions to the MAOP.

NOTE: Additional pressure testing of the segment may be desirable to raise the MAOP of the pipeline to a higher level. Schedule and conduct the pressure testing as desirable.

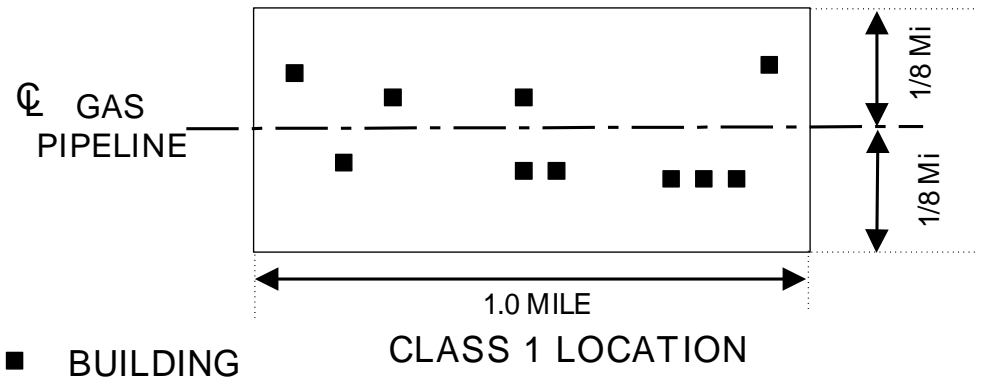
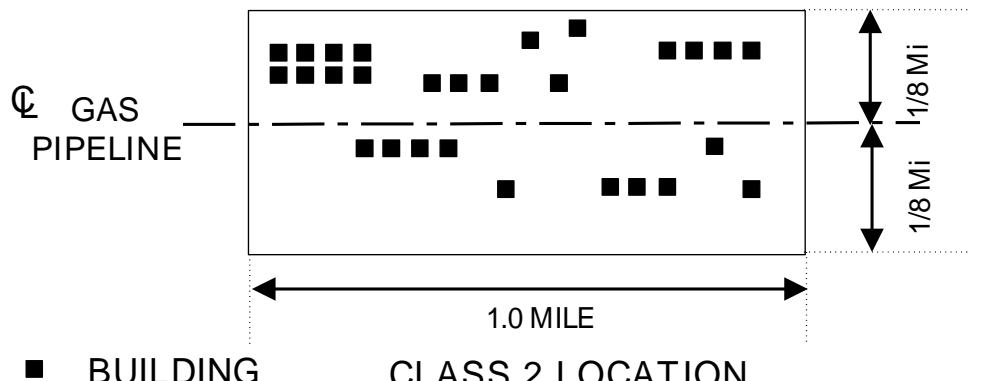
Class Location Determination

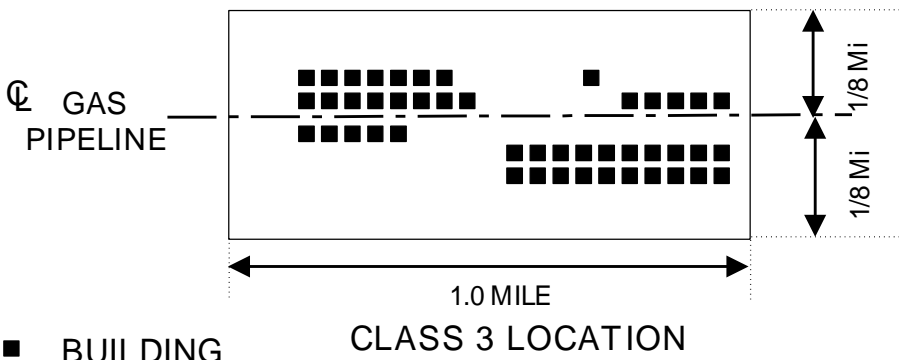
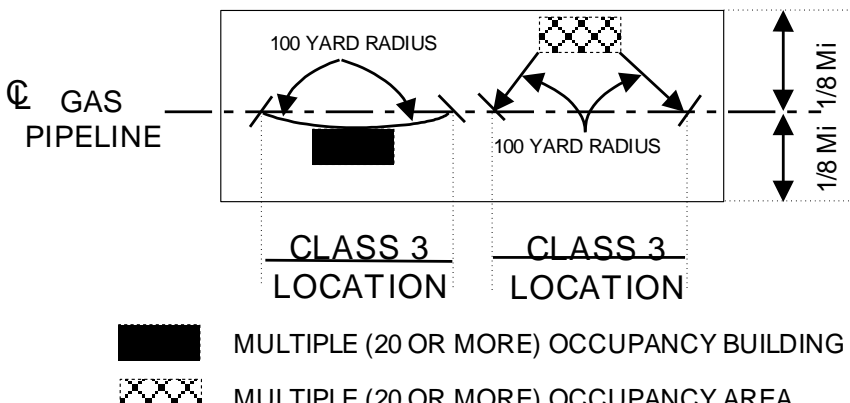
Gas pipelines are placed in class locations as described below. These classifications help determine some of the regulated activities that must be performed on the pipeline and the frequency of the activity. The Class Location Unit is an area extending six hundred and sixty feet (660) on either side of the centerline of any continuous one (1) mile length of pipeline.

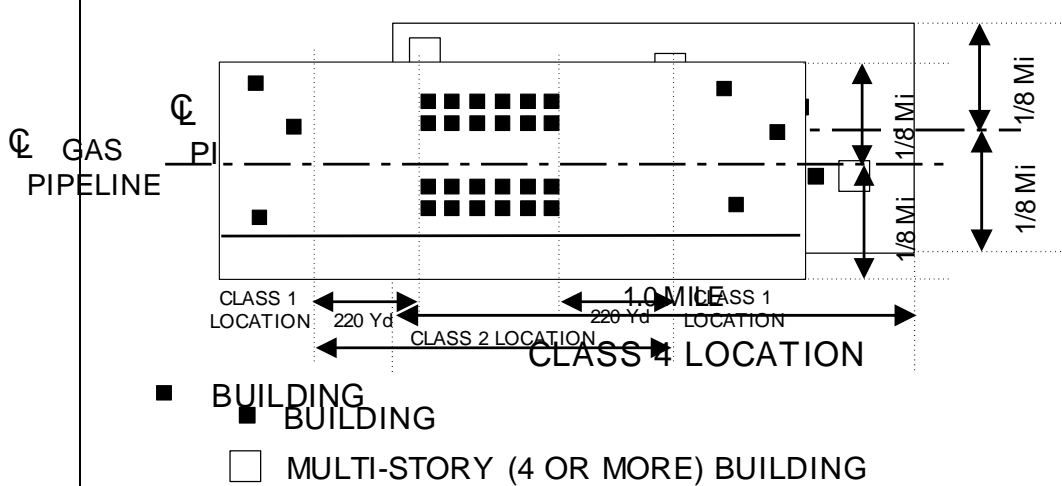
Class location studies will be conducted:

- a) For each existing pipeline or pipeline segment
- b) For each new pipeline or pipeline segment being constructed, and prior to testing. The class location determines in part, the maximum allowable operating pressure of the pipeline or pipeline segment.
- c) Whenever patrols or surveillance indicate changes in population density along the pipeline route.

The class location of onshore pipelines is broken up as follows:

Class Location	Criteria (Class Location Unit contains)
1	<p>Has ten (10) or fewer buildings intended for human occupancy.</p>  <p>■ BUILDING</p> <p>CLASS 1 LOCATION</p>
2	<p>Has more than ten (10) and fewer than forty-six (46) buildings intended for human occupancy.</p>  <p>■ BUILDING</p> <p>CLASS 2 LOCATION</p>

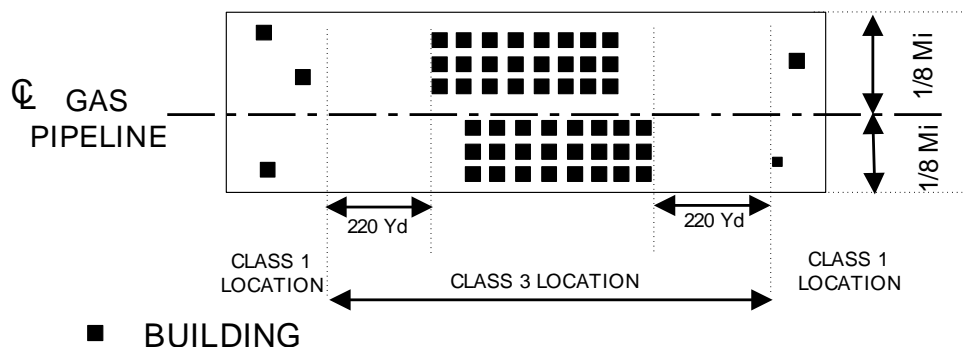
Class Location	Criteria (Class Location Unit contains)
3	<p>Has forty-six (46) or more buildings intended for human occupancy; or</p>  <p>■ BUILDING</p> <p>CLASS 3 LOCATION</p>
3	<p>An area where the pipeline lies within 300 feet of either a building or a small well-defined outside area (i.e., playground, recreation area, outdoor theater, or other place of public assembly that is occupied by twenty (20) or more people at least five (5) days per week for ten (10) weeks per twelve (12) month period. The days and weeks do not need to be consecutive.</p>  <p>■ MULTIPLE (20 OR MORE) OCCUPANCY BUILDING</p> <p>▨ MULTIPLE (20 OR MORE) OCCUPANCY AREA</p>

Class Location	Criteria (Class Location Unit contains)
4	<p>Dwellings with four (4) or more stories above ground are prevalent.</p>  <p>■ BUILDING ■ BUILDING □ MULTI-STORY (4 OR MORE) BUILDING</p>

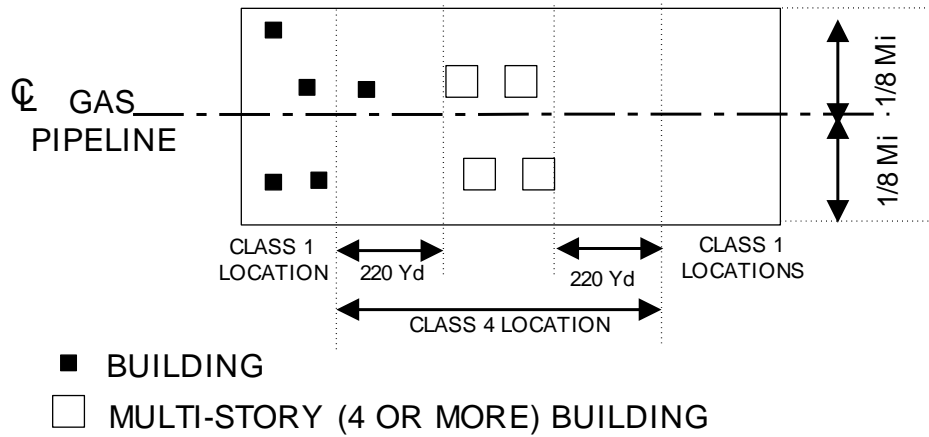
Class Location Unit Boundaries

The boundaries of the class location unit are adjusted as follows:

- Class 2 and 3 locations end 660 feet from the nearest building in the cluster of buildings that require the class location.



2. Class 4 location ends 660 feet from the nearest building with four (4) or more stories above ground.





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Description	The purpose of this procedure is to establish a system's business district and its boundaries.	
Regulatory Applicability	<input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	The Compliance Department and District Manager will review business districts every two years.	
Reference	49 CFR 192.721 49 CFR 192.723	<i>Distribution Systems: Patrolling</i> Distribution Systems: Leakage Surveys
Forms / Record Retention	F-192.5.1 <i>Business District Survey & Determination / Life of the system or until a new survey identifies a change or adds a new business district. Maintain the most recent documented survey.</i>	
Related Specifications	None	
OQ Covered Task	None	



Procedure Steps

1. Utilize previous business district forms and GIS layer of the potentially affected systems. Final determination of actual business district of each system is cooperative effort of the compliance department and district management.
2. Survey the systems to determine the current business districts. Document the new business districts on form F-192.5.1 or equivalent.
3. In the event of a business district change (increase), the following procedures are required:
 - i) The compliance department will submit the changes to the GIS technician.
 - ii) Confirm the changes with the District Managers so the pipeline patrols and the leakage surveys can be updated

Business District Classification

An area of two or more businesses within 100 yards (300 feet) of each other and within 100 yards along the linear length of any gas pipeline. The business district will extend 100 feet past the defined boundaries of the last business in the district.

A business district survey will be conducted each time a new distribution system is installed or when a system is acquired to confirm all business district(s) are identified using WTG's definition.



Description	The purpose of this procedure is to determine if a pipeline is a transmission line or a regulated onshore gathering line.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type C) <input checked="" type="checkbox"/> Reportable Gathering Pipelines (Type R) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 191.1	<i>Scope</i>
	49 CFR 191.8	<i>Definitions</i>
	49 CFR 191.15	<i>Incident Reporting</i>
	49 CFR 191.17	<i>Annual Reporting</i>
	49 CFR 191.23	<i>Safety Related Conditions</i>
	49 CFR 192.3	<i>Definitions</i>
	49 CFR 192.8	<i>How are Onshore Gathering Lines and Regulated Onshore Gathering Lines Determined?</i>
	49 CFR 192.9	<i>What Requirements Apply to Gathering Lines?</i>
	49 CFR 192.13	<i>What General Requirements Apply to Pipelines Regulated Under This Part?</i>
	49 CFR 192.18	<i>How to notify PHMSA</i>
	49 CFR 192.150	<i>Passage of internal inspection devices</i>
	49 CFR 192 452	<i>Converted pipelines and regulated onshore gathering lines</i>
	49 CFR 192.619	<i>MAOP</i>
Forms / Record Retention	Life of the Pipeline	
Related Specifications	None	
OQ Covered Task	None	



Procedure Steps

1. Review the previous jurisdictional determinations to ensure that the system type is aligned with CFR 192.8, or for newly constructed system, or systems that have a change in operations or a change in class location by conducting the following steps:
2. Determine if the use of the pipeline is consistent with the definitions of a gathering pipeline (Type A, Type B Type C or Type R), Transmission Pipeline or a Distribution System. If there is any question(s) in determining type of pipeline, contact the compliance department.
 - a) For WTG, a gathering pipeline is a pipeline transporting “unprocessed” gas from the producer to 1) processing plant, 2) distribution system or 3) a transmission system. The starting point is the downstream valve on the custody transfer point. The end point of gathering is the downstream valve for custody transfer point to one of the afore mention locations.
 - i) Definitions for different types of gathering pipelines:
 - (1) Type A: a metallic system which the MAOP produces a hoop stress of 20% or more of SMYS in a class 2, 3 or 4 location or a non-metallic system with an MAOP greater than 125 psig in a class 2, 3 or 4 location.
 - (2) Type B: a metallic system which the MAOP produces a hoop stress of less than 20% of SMYS in a class 2, 3 or 4 location or a non-metallic system with an MAOP equal to or less than 125 psig in a class 2, 3 or 4 location.
 - (3) Type C: a metallic system with an OD equal to or greater than 8.625” with an MAOP which produces a hoop stress of 20% of SMYS or greater in a class 1 location or a non-metallic system and the MAOP is greater than 125 psig in a class 1 location.
 - (4) Type R: all other onshore gathering lines in a class 1 location.
 - b) For WTG, a transmission pipeline is a pipeline transporting “processed” gas. The starting point of the pipeline is the downstream valve of the custody transfer meter from gathering. The end point of transmission is the downstream valve for custody transfer measurement to 1) a distribution system, 2) another transmission system 3) a large volume customer which can not be served by a distribution system
 - c) For WTG, a distribution system is a pipeline other than a gathering or transmission line which does not exceed 20% SMYS. The starting point of distribution is the downstream valve of the custody transfer meter. The end point is the downstream valve of the customer’s meter.
3. Conduct a class location survey per WTG’s O&M P-192.5
4. Calculate the stress level (if stress level is unknown, stress level must be determined following CFR 192 subsection C)
5. For gathering lines determined applicable regulations/procedures that are required to be followed for each type of gathering. Develop schedule for compliance tasks and implement:



Requirements	Gathering Type R	Gathering Type C	Gathering Type B	Gathering Type A
OPID	Required	Required	Required	Required
Reporting requirements found in CFR 191 (Incident Reporting 191.15, Annual Reporting 191.17 ¹ & Safe Related Conditions Reporting 191.25)	Required *Note Type R gathering lines are not required to report safety related condition	Required	Required	Required
192.8 9(b) Determine & maintain for life of pipeline the methodology the starting and end point of each gathering system	Required	Required	Required	Required
192.9(e)(1)(i) - Implement construction requirements for new/replaced/relocated/changed gathering lines following the 192 for Transmission Lines	NA	Required	Required	Required
192.9(e)(1)(ii) -Adopt corrosion control measures for steel pipe in accordance with 192, subpart I for transmission lines	NA	Required	Required	Required
192.9(e)(1)(iii) -Adopt damage prevention measures in accordance with 196.614	NA	Required	Required	Required



192.9 (e)(1)(iv) -Develop and implement emergency plans according to 192.615	NA	Required	Required	Required
192.9(e)(1)(v) -Adopt public awareness programs in accordance with 192.616	NA	Required but there are Exceptions see footnote ²	Required	Required
192.9(1)(vi) - Install and maintain line markers according to 192.707 transmission	NA	Required but there are Exceptions see footnote ²	Required	Required
192.9(e)(1)(vii) -Conduct leak surveys in accordance with 192.706, using leak detection equipment and repair discovered leaks in accordance with 192.703(c)	NA	Required but there are Exceptions see footnote ²	Required	Required
192.9(e)(2) -Establish MAOP in accordance with 192.619	NA	Required but there are Exceptions see footnote ³	Required	Required
192.610 Applicable Block valve spacing and RMV valves 192.179(e), 192.179(f), and 192.634	NA	NA	NA	Required
All other regulations within CFR 192 except 192.150, 192.285(e), 192.483, 192.506, 192.607,192.619(e), 192.624, 192.710, 192.712, and subpart O (transmission integrity management)	NA	NA	NA	Required

¹ Annual Report to commence for CY 2022, reporting date no later than 3/15/2023

² Two methods to determine exceptions Method 1 no BIO or other impacted site within the PIR (0.73 safety factor must be used in the calculation) Method 2 No BIO or impacted site within the class 1 location



³ Not required for pipeline that are ≤ 16 "

6. Document finding on WTG F-192.8



Description	The purpose of this procedure is to convert steel pipelines that have not been previously operated under 49 CFR Part 192 to service under this part.	
Regulatory Applicability	Pipelines converted to service regulated by 49 CFR Part 192. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹	
Frequency	As needed	
Reference	49 CFR 192.14 49 CFR 192.452 LA Title 43 Part XIII 514 LA Title 43 Part XIII 2103	<i>Conversion to Service Subject to This Part Applicability to Converted Pipelines Conversion to Service Subject to This Part Applicability to Converted Pipelines</i>
Forms / Record Retention	F-192.14	<i>Conversion of Service / Life of Pipeline System</i>
Related Specifications	None	
OQ Covered Task	Review the covered task list at the time of conversion to determine which tasks are being performed in the field and ensure individuals are qualified. (In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

1. Review records of the pipeline design, construction, operation, and maintenance history to determine whether or not the pipeline is in satisfactory condition. (Form 192.14)
2. If available historical records are insufficient to determine that the pipeline is in satisfactory condition, perform needed tests on the pipeline to determine if the pipeline is in satisfactory condition.
3. Visually inspect the pipeline right-of-way on all above-ground segments and selected underground segments for physical defects that could impair the pipeline.
4. Correct all known unsafe defects and conditions.
5. Pressure test the line in accordance with Procedure P-192.501: *Steel Pipeline Pressure Test Requirements* to substantiate the maximum allowable operating pressure (MAOP).
6. Determine the Maximum Allowable Operating Pressure (using procedure P-192.619).

Note: If any variable required determining the design pressure under 49 CFR 192.105 is unknown, one of the following pressures is to be used as design pressure:

- 80% of the first test pressure that produces a yield under section N5 of ASME B31.8, Appendix N, to produce a stress equal to the yield strength, reduced by the appropriate factor from the table below; or

Class Location	Factors ²
1	1.25
2	1.25
3	1.5
4	1.5

- If the pipe is 12 ¾ inches or less in outside diameter and is not tested to yield, 200 psi.
7. Pressure-test the line to substantiate the new line MAOP (using procedure P-192.501).
 8. Determine corrosion protection requirements (using procedure P-192.455). Install corrosion protection equipment as needed.
 9. Complete all forms and distribute as appropriate. Retain a copy in the DOT file for the life of the pipeline.

² For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe rider, the factor is 1.5.



Description	The purpose of this procedure is to establish customer notification guidelines.
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**Regulatory
Applicability**

- ☐ Regulated Transmission Pipelines
- ☐ Regulated Gathering Pipelines (Type A)
- ☐ Regulated Gathering Pipelines (Type B)
- ☒ Regulated Distribution Pipelines

This applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment.

For the purpose of this procedure, "customer's buried piping" does not include branch lines that serve:

- yard lanterns
- pool heaters
- other types of secondary equipment.

Also, "maintain" means monitor for corrosion according to §192.465 if the customer's buried piping is metallic, survey for leaks according to §192.723, and if an unsafe condition is found:

- shut off the flow of gas,
- advise the customer of the need to repair the unsafe condition, or
- repair the unsafe condition.

Frequency	Upon the beginning of each customer service agreement.
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Reference	49 CFR 192.16 <i>Customer Notification</i> LA Title 43 Part XIII 516 <i>Customer Notification</i>
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Forms / Record Retention	None / Evidence of Notices within previous 3 years
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Related Specifications	None
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OQ Covered Task	None
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Procedure

West Texas Gas will issue each customer a notification packet upon the beginning of each service agreement that addresses each of the following:

1. West Texas Gas does not maintain the customer's buried piping.
2. If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
3. Buried gas piping should be :
 - a. Periodically inspected for leaks;
 - b. Periodically inspected for corrosion if the piping is metallic; and
 - c. Repaired if any unsafe condition is discovered.
4. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.
5. West Texas Gas (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

West Texas Gas will make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

1. A copy of the notice currently in use; and
2. Evidence that notices have been sent to customers within the previous 3 years.



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Description	This procedure is used when notification is required to PHMSA for non-emergencies.
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Regulatory Applicability	
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Frequency	As required
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Reference	49 CFR 192.8	<i>Onshore gathering pipeline determination</i>
	49 CFR 192.9	<i>What requirements apply to gathering pipelines</i>
	49 CFR 192.13	<i>What general requirements apply to pipelines</i>
	49 CFR 192.179	<i>Transmission line valves</i>
	49 CFR 192.461	<i>External corrosion control: Protective coating</i>
	49 CFR 192.506	<i>Transmission lines: Spike hydrotests pressure test</i>
	49 CFR 192.607	<i>Verification pipeline material properties and attributes</i>
	49 CFR 192.619	<i>MAOP</i>
	49 CFR 192.624	<i>MAOP Reconfirmation</i>
	49 CFR 192.632	<i>Engineering critical assessment MAOP</i>
	49 CFR 192.634	<i>Shut-off valves rupture mitigation</i>
	49 CFR 192.636	<i>Response to a rupture (RMV's)</i>
	49 CFR 192.710	<i>Transmission assessments outside of HCA's</i>
	49 CFR 192.712	<i>Analysis of predicted failure</i>
	49 CFR 192.714	<i>Repair criteria</i>
	49 CFR 192.745	<i>Valve maintenance</i>
	49 CFR 192.917	<i>Pipeline integrity potential threats</i>
	49 CFR 192.927	<i>ICDA</i>
	49 CFR 192.933	<i>Actions to address integrity issues</i>
	49 CFR 192.937	<i>Continual process and assessment to address integrity</i>



**Forms / Record
Retention**

None

**Related
Specifications**

None

**OQ Covered
Task**

None



Procedure Steps

1. WTG must provide any non-emergency notification required by CFR 191 or 192 by
 - (a) Sending the notification by electronic mail to InformationResourcesManager@dot.gov; or
 - (b) Sending the notification by mail to ATTN: Information Resources Manager,
DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE,
Washington, DC 20590.
2. WTG must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.
3. Unless otherwise specified, if WTG submits, pursuant to § 192.8, § 192.9, § 192.13, § 192.179, § 192.319, § 192.461, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, § 192.917, § 192.921, § 192.927, § 192.933, or § 192.937, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., “other technology” or “alternative equivalent technology”) than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. WTG may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing WTG that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.



Description	This procedure is used to establish proper storage and handling guidelines of plastic and steel pipe.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Prior to purchasing, storing or handling plastic pipe and steel as needed	
Reference	49 CFR 192.65 49 CFR 192.69	<i>Transportation of Pipe</i> <i>Plastic Pipe Storage and Handling</i>
Forms / Record Retention	WTG-1400	<i>Project Report Form / Life of Pipeline System</i>
Related Specifications	API RP 5LT ASTM D2513, D3350, AMSE B31.8	
OQ Task	Covered	None



Plastic Pipe Procedure Steps

Qualifying Storage Specifications:

All individuals purchasing and storing plastic pipe must document for the life of the pipeline the method in which the pipe was stored in form WTG-1400 and adhere to the procedures as described below:

1. High Density pipe as defined in ASTM Specification D3350
 - A. Indoor storage - Plastic pipe that is stored indoors shall be adequately supported to prevent deformation of pipe, protected from UV exposure and harmful chemicals, and may be deemed acceptable for use for 10 years or more.
 - B. Outdoor Storage - Plastic pipe that is stored outdoors shall be adequately supported to prevent deformation of pipe, protected from excessive heat and harmful chemicals, and may be suitable for use in a timeframe not to exceed 10 years.
2. Medium Density pipe as defined in ASTM Specification D3350
 - A. Indoor Storage - Plastic pipe that is stored indoors shall be adequately supported to prevent deformation of pipe, protected from UV exposure and harmful chemicals, and may be deemed acceptable for use for 3 years or more.
 - B. Outdoor Storage- Plastic pipe that is stored outdoors shall be adequately supported to prevent deformation of pipe, protected from excessive heat and harmful chemicals, and may be suitable for use in a timeframe not to exceed 3 years.

Handling Specifications:

All individuals handling plastic pipe must document for the life of the pipeline in form WTG-1400 the method in which the pipe was handled and adhere to the procedures as described below:

1. Plastic pipe shall be carefully inspected for cuts, scratches, gouges, and other imperfections before use, and any pipe containing harmful imperfections shall be cut out and replaced.
2. Care shall be exercised to avoid rough handling of plastic pipe. It shall not be pushed or pulled over sharp projections, or it shall not have other objects dropped on it. Care shall be taken to prevent kinking or buckling, and any kinks or buckles that occur shall be removed by cutting out as a cylinder.
3. Care shall be exercised at all times to protect the plastic material from fire, excessive heat, or harmful chemicals.
4. Each installation shall be field inspected to detect harmful imperfections. Any such imperfections found shall be eliminated.



Steel Pipe Procedure Steps

Transportation & Handling Specifications:

All individuals responsible for ordering of steel pipe must inform the vendor that the pipe must be shipped in accordance with CFR 192.65. Specifically, paragraph (c) and API RP 5LT as all pipe is shipped by truck for WTG at this time. If there are any questions concerning the context of API RP 5LT, please contact the compliance department.

Handling steel pipe must document for the life of the pipeline in form WTG-1400 the method in which the pipe was handled and adhere to the procedures as described below:

1. Steel pipe shall be carefully inspected for cuts, scratches, gouges, and other imperfections within coating and pipe before use, and any pipe containing harmful imperfections shall be cut out and/or not accepted.
2. Care shall be exercised to avoid rough handling of steel pipe. It shall not be pushed or pulled over sharp projections, or it shall not have other objects dropped on it. Care shall be taken to prevent damage. In the event of damage during handling shall be removed by cutting out as a cylinder.

Qualifying Storage Specifications:

All individuals purchasing and storing steel pipe must document for the life of the pipeline the method in which the pipe was stored in form WTG-1400 and adhere to the procedures as described below:

1. Outdoor Storage – Steel pipe that is stored outdoors shall be adequately supported to prevent deformation of pipe, protected from excessive heat and harmful chemicals.
2. If pipe is ordered and received for a specific job:
 - A. Upon receipt of pipe, Mill Test documentation must be reviewed and ensure that documentation matches pipe received.
 - B. File Mill Test documentation in job folder for life of the pipe a central location
 - C. If pipe is ordered and received for a standby / emergency repair pipe and used at a future date:
 - D. Upon receipt of pipe, Mill Test documentation must be reviewed and ensure that documentation matches pipe received.
 - E. File Mill Test documentation in a known location and held for future use when pie is installed.
3. Care shall be exercised at all times to protect the steel material from fire, excessive heat, or harmful chemicals.
4. Each installation shall be field inspected to detect harmful imperfections. Any such imperfections found shall be eliminated.



Description	To design pipe that can withstand the anticipated external pressures and loads that will be imposed on the pipe after installation and to determine the pressure the pipe is designed to carry.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Distribution Pipelines	
Applies to	All DOT regulated gas pipelines.	
Frequency	As needed for new installation or replaced pipe.	
Safety and Environmental Precautions	Thorough review of each new pipeline design is required to ensure that all design/configuration are minimizing/reducing natural gas releases.	
References	49 CFR 192.101	Scope
	49 CFR 192.103	General
	49 CFR 192.105	Design Formula for Steel Pipe
	49 CFR 192.107	Yield Strength (S) for steel pipe
	49 CFR 192.109	Nominal wall thickness (t) for steel Pipe
	49 CFR 192.111	Design factor (F) for steel pipe
	49 CFR 192.112	Additional design requirements for steel pipe using alternative maximum allowable operating Pressure
	49 CFR 192.113	Longitudinal joint factor (E) for steel pipe
	49 CFR 192.115	Temperature derating factor for steel pipe
	49 CFR 192.121	Design of plastic pipe
	49 CFR 192.123	Design limitations for plastic pipe
	49 CFR 192.143	General requirements
	49 CFR 192.144	Qualifying metallic components
	49 CFR 192.145	Valves
	49 CFR 192.147	Flanges and flange accessories
	49 CFR 192.149	Standard fittings
	49 CFR 192.150	Passage of internal inspection devices
	49 CFR 192.153	Components fabricated by welding
	49 CFR 192.155	Welded branch connections
	49 CFR 192.157	Extruded outlets
	49 CFR 192.159	Flexibility
	49 CFR 192.161	Supports and anchors
	49 CFR 192.179	Transmission line valves



49 CFR 192.181	Distribution line valves
49 CFR 192.183	Vaults: Structural design requirements
49 CFR 192.185	Vaults: Accessibility
49 CFR 192.187	Vaults: Sealing, venting and ventilation
49 CFR 192.189	Vaults: Drainage and waterproofing
49 CFR 192.191	Design pressure of plastic fittings
49 CFR 192.193	Valve installation in plastic pipe
49 CFR 192.195	Protection against accidental over-pressuring
49 CFR 192.197	Control of the pressure of gas delivered from high pressure distribution system
49 CFR 192.199	Requirements for design of pressure relief and limiting devices
49 CFR 192.201	Required capacity of pressure relieving and limiting stations
49 CFR 192.203	Instrument, control, and sampling pipe and components
49 CFR 192.317	Protection from hazards

Agency 82 KAC Article 11 Section 4: Transportation of natural and other gas by pipeline minimum safety standards

Prerequisites

N/A

**Forms / Record
Retention**

None

**Related
Procedures**

None

Procedure Steps

Engineering will use this procedure to ensure pipe and components are designed in accordance with the design regulations in 49 CFR Part 192 which prohibits the use of cast iron, wrought iron, or bare steel pipelines.

Design Pressure of Steel Pipe (49 CFR Subpart C)

1. Determine the type of pipe to be used. From this, determine the Yield Strength as follows:
 - a) For pipe manufactured in accordance with a specification listed in section I of appendix B of 49 CFR 192, the yield strength is the SMYS stated in the listed specification, if that value is known.
 - b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B of 49 CFR Part 192 or whose specification or tensile properties are unknown, the yield strength is one of the following:
 - i. If the pipe is tensile tested in accordance with section II-D of appendix B of 49 CFR Part 192, the lower of the following:
 - a. 80 percent of the average yield strength determined by the tensile tests.
 - b. The lowest yield strength determined by the tensile tests.
 - ii. If the pipe is not tensile tested as provided in paragraph (b)(i) above, 24,000 p.s.i.
2. Determine the wall thickness of the pipe.
 - a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.
 - b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.
3. Determine the nominal outside diameter of the pipe in inches.
4. Determine the design factor for the pipe as follows:
 - a) Except as otherwise provided below, the design factor to be used in the design formula is determined in accordance with the following table:

Class location	Design factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

- b) A design factor of 0.60 or less must be used in the design formula for steel pipe in Class 1 locations that:
 - i. Crosses the right-of-way of an unimproved public road, without a casing;

- ii. Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard-surfaced road, a highway, a public street, or a railroad;
- iii. Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
- iv. Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.
- c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula for uncased steel pipe that crosses the right-of-way of a hard-surfaced road, a highway, a public street, or a railroad.
- d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula for-
 - i. Steel pipe in a compressor station, regulating station, or measuring station; and
 - ii. Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.
- 5. Determine the longitudinal joint factor from the table below:

Specification	Pipe class	Longitudinal joint factor (E)
<u>ASTM A 53/A53M</u>	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
<u>ASTM A 106</u>	Seamless	1.00
<u>ASTM A 333/A 333M</u>	Seamless	1.00
	Electric resistance welded	1.00
<u>ASTM A 381</u>	Double submerged arc welded	1.00
<u>ASTM A 671</u>	Electric-fusion-welded	1.00
<u>ASTM A 672</u>	Electric-fusion-welded	1.00
<u>ASTM A 691</u>	Electric-fusion-welded	1.00
<u>API 5 L</u>	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80



Other	Pipe 4 inches (102 millimeters) or less	.60
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Note: If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

6. Determine the temperature derating factor from the table below:

Gas temperature in degrees Fahrenheit	Temperature derating factor (T)
250°F or less	1.000
300°F	0.967
350°F	0.933
400°F	0.900
450°F	0.867

Note: For intermediate gas temperatures, the derating factor is determined by interpolation.

7. Use the items determined above to calculate the design pressure for the pipeline using the following formula:.

$$P=(2 St/D) \times F \times E \times T$$

Where:

P =Design pressure in pounds per square inch gauge.

S =Yield strength in pounds per square inch determined in accordance with [#1](#) above.

D =Nominal outside diameter of the pipe in inches.

t =Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with [#2](#) above. Additional wall thickness required for concurrent external loads in accordance with [§192.103](#) may not be included in computing design pressure.

F =Design factor determined in accordance with [#4](#) above.

E =Longitudinal joint factor determined in accordance with [#5](#) above.

T =Temperature derating factor determined in accordance with [#6](#) above.

Note: If the pipe was subjected to cold expansion to meet the SMYS and then subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75% of the pressure determined here if the temperature of the pipe exceeds 900°F at any time or is held above 600°F for more than 1 hour.

8. If the pipe is to be designed using alternative maximum allowable operating pressure, all additional requirements of 49 CFR 192.112 will be satisfied.

Design Pressure of Plastic Pipe

1. Determine the type of pipe to be used. For Polyethylene pipe (PE), select the thermoplastic pipe value (S) from pipe grade row and the design temperature column from the following table:

	Design Temp (°F)			
Grade	73	100	120	140
2306	1250	1250	1000	800
2406	1250	1250	1000	800
3406	1250	1250	1000	800
3408 / 4710	1600	1250	1000	800

2. Determine the wall thickness (t) of the pipe by dividing the outside diameter(D) by the pipe's Standard dimension ratio (SDR).
3. The design factor 'DF' is 0.32.
4. Use the items above to calculate the design pressure for the pipeline using the following formula:
 $P = 2S \times (t/D - t) \times DF$, or
 $P = (2S / (SDR - 1)) \times DF$
5. Check final selection and design pressure against the limitations below:
 - a) Design pressure cannot exceed 100 psig when used in distribution systems or Class 3 and 4 locations.
 - b) Plastic pipe cannot be used with operating temperatures in 49 CFR 192.121 (b).
 - c) The wall thickness may not be less than 0.090 inches, unless specified in the following table:

PE pipe: minimum wall thickness and SDR values		
Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½ CTS	0.090	7
½ IPS	0.090	9.3
¾ CTS	0.090	9.7
¾ IPS	0.095	11
1 CTS	0.099	11
1 IPS	0.119	11
1 ¼ IPS	0.151	11
1 ½ IPS	0.173	11

2	0.216	11
3	0.259	13.5
4	0.265	17
6	0.315	21
8	0.411	21
10	0.512	21
12	0.607	21
16	0.762	21
18	0.857	21
20	0.952	21
22	1.048	21
24	1.143	21

* Copper Tubing Size (CTS) Iron Pipe Size (IPS)

- d) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:
 - i. The material designation code is PE2406 or PE3408.
 - ii. The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and
 - iii. The wall thickness is not less than 0.062 inches (1.57 millimeters).
- e) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - i. The design pressure does not exceed 125 psig
 - ii. The material designation code is PE2708 or PE4710
 - iii. The pipe has a nominal size (IPS or CTS) of 24 inches or less and
 - iv. The wall thickness for a given outside diameter is not less than that listed in the above table.

Other plastic pipe materials will be designed according to 49 CFR 192.121.

Design of Casings:

For each casing installed on a regulated gathering, transmission or distribution main pipeline, the casing must comply with:

1. The casing must be designed to withstand superimposed loads.
2. If there is a possibility of water entering the casing, the end must be sealed.
3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the MAOP pressure of the pipeline, the casing must be designed to hold the pressure at a stress level of < 72% SMYS.
4. If vents are installed on casing, the vents must be protected to prevent water from entering the casing.

Pipeline Components:

Ensure each component that will be installed in the pipeline complies with the following:



1. WTG must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.
2. For each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.
3. It can withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component. Note: These components must also meet the requirements for corrosion control requirements in Subpart I of 49 CFR Part 192.
4. If manufactured in accordance with any other edition of a document incorporated by reference in [§192.7](#) or Appendix B of 49 CFR Part 192, -
 - a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and
 - b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in [§192.7](#) or appendix B of 49 CFR Part 192:
 - i. Pressure testing
 - ii. Materials; and
 - iii. Pressure and temperature ratings.
5. Emergency Valves (49 CFR 192.145 / 19 CFR 192.179)
 - a) Meet the minimum requirements of [API 6D](#) or to a national or international standard that provides an equivalent performance level. An emergency valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
 - b) Can meet the anticipated operating conditions.
 - c) Each transmission line has sectionalizing emergency block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:
 - i. Each point on the pipeline in a Class 4 location must be within 2 ½ miles of a valve.
 - ii. Each point on the pipeline in a Class 3 location must be within 4 miles of a valve.
 - iii. Each point on the pipeline in a Class 2 location must be within 7 ½ miles of a valve.
 - iv. Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.
 - d) Each sectionalizing block valve on a transmission line complies with the following:
 - i. The valve and the operating device to open or close the valve are readily accessible and protected from tampering and damage.
 - ii. The valve is supported to prevent settling of the valve or movement of the pipe to which it is attached.
 - e) Each section of a transmission line between main line emergency valves has a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge is located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.
 - f) Each high-pressure distribution system must have emergency valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

- g) Each regulator station controlling the flow or pressure of gas in a distribution system must have an emergency valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.
- h) Each emergency valve on a main installed for operating or emergency purposes must comply with the following:
 - i. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.
 - ii. The operating stem or mechanism must be readily accessible.
 - iii. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.
- 6. Flange or flange accessory
 - a) Meet the minimum requirements of [ASME/ANSI B16.5](#), [MSS SP-44](#), or the equivalent.
 - b) The flange assembly is able to withstand the maximum pressure at which the pipeline is to be operated and maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
- 7. Threaded fittings have a minimum metal thickness that is not less than specified for the pressures and temperatures in the applicable standards referenced in 49 CFR Part 192, or their equivalent.
- 8. Each steel butt-welding fitting has pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting is at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.
- 9. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, is established in accordance with paragraph UG-101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.
- 10. Each prefabricated unit that uses plate and longitudinal seams will be designed, constructed, and tested in accordance with the ASME Boiler and Pressure Vessel Code.
- 11. Orange-peel bull plugs and orange-peel swages are not used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.
- 12. Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails are not used on pipe that either operates at 100 p.s.i. gauge, or more, or is more than 3 inches nominal diameter.
- 13. Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, is designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.
- 14. Each extruded outlet is suitable for anticipated service conditions and at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.
- 15. Each pipeline is designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

Passage of Internal Inspection Devices

New transmission lines and replacement of pipe and components must be designed and constructed to allow for instrumented internal inspection devices in accordance with NACE SP0102, Section 7. This requirement does not include manifolds, compressor, meter, and regulator stations, line pipe sizes that cannot accommodate ILI tools, and other exceptions listed in 49 CFR 192.150.

Launcher and receiver safety

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

Vaults

1. Ensure vaults meet the following structural design requirements.
 - a) able to meet the loads which may be imposed upon it, and to protect installed equipment.
 - b) enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.
 - c) each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.
2. Ensure each vault is located in an accessible location and, so far as practical, away from:
 - a) Street intersections or points where traffic is heavy or dense.
 - b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
 - c) Water, electric, steam, or other facilities.
3. Ensure each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, is sealed, vented or ventilated as follows:
 - a) When the internal volume exceeds 200 cubic feet:
 - i. The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches in diameter.
 - ii. The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
 - iii. The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
 - b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet:
 - i. If the vault or pit is sealed, each opening must have a tight-fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
 - ii. If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
 - iii. If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

- c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.
- 4. Ensure each vault is designed so as to minimize the entrance of water and is not connected by a drain connection to any other underground structure if the vault contains gas piping.
- 5. Ensure electrical equipment in vaults conforms to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/[NFPA 70](#).

Supports and Anchors

- 1. Ensure pipeline and its associated equipment has enough anchors or supports to:
 - a) Prevent undue strain on connected equipment
 - b) Resist longitudinal forces caused by a bend or offset in the pipe; and
 - c) Prevent or damp out excessive vibration.
- 2. Each exposed pipeline has enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.
- 3. Each support or anchor on an exposed pipeline is made of durable, noncombustible material and must be designed and installed as follows:
 - a) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
 - b) Provision must be made for the service conditions involved.
 - c) Movement of the pipeline may not cause disengagement of the support equipment.
- 4. Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS will comply with the following:
 - a) A structural support may not be welded directly to the pipe.
 - b) The support must be provided by a member that completely encircles the pipe.
 - c) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.
- 5. Each underground pipeline that is connected to a relatively unyielding line or other fixed object has enough flexibility to provide for possible movement, or has an anchor that will limit the movement of the pipeline.
- 6. Each underground pipeline that is being connected to new branches has a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

Design pressure of plastic fittings

Design pressure for fittings exceeds or is equal to pipe design pressure. Ensure thermosetting fittings for plastic pipe conforms to ASTM 2513.

Valve installation in plastic pipe

Design pressure for valves exceeds or is equal to pipe design pressure. Ensure each valve installed in plastic pipe protects the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

Protection against accidental over-pressuring

General requirements

Except as provided in §192.197, ensure each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, has pressure relieving or pressure limiting devices that meet the requirements below.

Additional requirements for distribution systems

Ensure each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system -

- (1) Has pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
- (2) Is designed so as to prevent accidental overpressuring.

Control of the pressure of gas delivered from high-pressure distribution systems

1. If the maximum actual operating pressure of the distribution system is 60 p.s.i. gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:
 - a) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.
 - b) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.
 - c) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
 - d) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
 - e) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
 - f) A self-contained service regulator with no external static or control lines.
2. If the maximum actual operating pressure of the distribution system is 60 p.s.i. gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

3. If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. gauge, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:
 - a) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. gauge. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. gauge or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. gauge or less), and remains closed until manually reset.
 - b) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.
 - c) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. gauge. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.
 - d) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

Requirements for design of pressure relief and limiting devices

Except for rupture discs, ensure each pressure relief or pressure limiting device:

1. Is constructed of materials such that the operation of the device will not be impaired by corrosion.
2. Has valves and valve seats that are designed not to stick in a position that will make the device inoperative
3. Is designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;
4. Has support made of noncombustible material.
5. Has discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard.
6. Is designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity.
7. Where installed at a district regulator station to protect a pipeline system from overpressuring, is designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and
8. Except for a valve that will isolate the system under protection from its source of pressure, is designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

Required capacity of pressure relieving and limiting stations

1. Ensure each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline has enough capacity, and is set to operate, to insure the following:
 - a) In a low-pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
 - b) In pipelines other than a low-pressure distribution system:
 - i. If the maximum allowable operating pressure is 60 p.s.i. gauge or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower.
 - ii. If the maximum allowable operating pressure is 12 p.s.i. gauge or more, but less than 60 p.s.i.) gauge, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. gauge; or
 - iii. If the maximum allowable operating pressure is less than 12 p.s.i. gauge, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.
2. When more than one pressure regulating or compressor station feeds into a pipeline, ensure relief valves or other protective devices are installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.
3. Relief valves or other pressure limiting devices will be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

Instrument, control, and sampling pipe and components

Note: This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

1. *Ensure all* materials employed for pipe and components are designed to meet the particular conditions of service and the following:
 - a) Each takeoff connection and attaching boss, fitting, or adapter is made of suitable material, can withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and is designed to satisfactorily withstand all stresses without failure by fatigue.
 - b) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve is installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves are installed where necessary.
 - c) Brass or copper material is not used for metal temperatures greater than 400° F.
 - d) Pipe or components that may contain liquids are protected by heating or other means from damage due to freezing.
 - e) Pipe or components in which liquids may accumulate have drains or drips.



- f) Pipe or components subject to clogging from solids or deposits have suitable connections for cleaning.
- g) The arrangement of pipe, components, and supports provides safety under anticipated operating stresses.
- h) Each joint between sections of pipe, and between pipe and valves or fittings, is made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints are not used. Expansion is allowed for by providing flexibility within the system itself. Each control line is protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.



Description	This procedure outlines the minimum record keeping requirements for material properties and pipe design.	
Regulatory Applicability	<input checked="" type="checkbox"/> All Steel Transmission Pipelines	
Reference	49 CFR Part 192.127	Records: Pipe Design
	49 CFR Part 192.67	Records: Material Properties
Forms / Record Retention	Records must be kept for the life of the pipeline.	
Related Specifications	None	
OQ Covered Task	None	



Procedure Steps

Pipe Design

1. For steel transmission pipelines installed or repaired after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with §192.103 and documenting that the determination of design pressure for the pipe is made in accordance with §192.105.
2. For steel transmission pipelines installed or repaired on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§192.103 and 192.105, operators must retain such records for the life of the pipeline.
3. For steel transmission pipeline segments installed or repaired on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.

Material Properties

1. For steel transmission pipelines installed or repaired after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed or repaired.
2. For steel transmission pipelines installed or repaired on or before July 1, 2020], if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed or repaired, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§192.53 and 192.55, operators must retain such records for the life of the pipeline.
3. For steel transmission pipeline segments installed or repaired on or before July 1, 2020], if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.



Description	This procedure is used to properly install and repair support structures and pipe insulators.
Regulatory Applicability	All supported aboveground pipe <input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Distribution Pipelines
Frequency	As needed
Reference	49 CFR 192.161 <i>Supports and Anchors</i> LA Title 43 Part XIII 1121 <i>Supports and Anchors</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	0961 Above Ground Supports and Anchors: Inspection, Preventive and Corrective Maintenance (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

1. Installation

- a) Determine proper construction, spacing and design of pipe support including support structure foundation through company practice, standards or engineering design. Blueprints and Isometric drawings should be used to ensure that supports are located correctly as per engineering specifications.

Each pipeline and its associated equipment must have enough anchors or supports to:

- i) Prevent undue strain on connected equipment;
- ii) Resist longitudinal forces caused by a bend or offset in the pipe,
- iii) Prevent or damp out excessive vibration.

Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

- b) Obtain proper tools and equipment to complete the installation.
- c) Install temporary support (If applicable).
- d) Lift pipe with a jack using pipe protective device (i.e. pipe saddles). Hoist with proper rigging techniques or another appropriate lift technique (If required).
- e) Install replacement/additional support and insulator in accordance with company practice, standards or engineering design. Each support or anchor on an exposed pipeline must be made of durable, non-combustible material. Provisions must be made for the service conditions involved.
- f) Each support on an exposed pipeline operated at a stress level of 50 percent or more SMYS must comply with the following:
 - i) A structural support may not be welded directly to the pipe.
 - ii) The support must be provided by a member that completely encircles the pipe.
 - iii) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.
- g) Lower pipe to desired position (If applicable).
- h) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement or it must have an anchor that will limit the movement of the pipeline.
- i) Each underground pipeline that is being connected to new branches must have a firm foundation to prevent lateral and vertical movement.
- j) Remove temporary pipe support (If applicable).



k) If using adjustable support, adjust support heights to insure a level pipe run.

2. Repair

- a) Determine proper construction and design of pipe support in accordance with company practice, standards or engineering design.
- b) Prior to repair process, isolate and blow down segment. Lift pipe with a jack using pipe protective device (i.e. pipe saddles). Hoist with proper rigging techniques or another appropriate lift technique (If applicable).
- c) Remove existing pipe support.
- d) Look for signs of significant corrosion that will require further inspection, including:
 - i) heavy localized oxidation
 - ii) bubbling paint
 - iii) visible pitting
- e) Obtain proper tools and equipment to complete the installation.
- f) Install temporary support (If applicable).
- g) A qualified individual will perform a pipe wall inspection (If applicable).
- h) Repair pipe support in accordance with WTG's practice, standards or engineering design
- i) Install repaired support and insulator. Follow WTG's O&M procedure above for Installation of support.
- j) Lower pipe to desired position.
- k) Remove temporary pipe support.
- l) If using adjustable support, adjust support height to insure a level pipe run
- m) Purge and place segment into service
- n) Document installation (Form WTG 1400)



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Description	This procedure provides guidance regarding the requirements for the design and construction of compressor stations. This includes make provisions for liquid removal, emergency shutdown, pressure limiting devices, additional safety equipment and ventilation.	
Regulatory Applicability	All supported aboveground pipe <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.163	<i>Compressor stations: Design and construction</i>
	49 CFR 192.165	<i>Compressor stations: Liquid removal</i>
	49 CFR 192.167	<i>Compressor stations: Emergency shutdown</i>
	49 CFR 192.169	<i>Compressor stations: Pressure limiting devices</i>
	49 CFR 192.171	<i>Compressor stations: Additional safety equipment</i>
	49 CFR 192.173	<i>Compressor stations: Ventilation</i>
Forms / Record Retention	None	
Safety and Environmental Precautions	Thorough review of each new compressor design is required to ensure that all design/configuration are minimizing/reducing natural gas releases.	
Related Specifications	National Electrical Code ANSI/NFPA 70 Section VIII of the ASME Boiler and Pressure Vessel Code	

¹ If the line is new, replaced, relocated or changed.



**OQ Covered
Task**

None

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

This procedure is not intended to provide a step-by-step process for the design and construction of a compressor station. Rather, it provides guidance regarding the pipeline safety requirements for the design and construction of compressor stations mandated by 49 CFR 192.

Compressor Station Design and Construction

1. Location of compressor building
 - a) Each main compressor building of a compressor station must be located on property under the control of the operator. (Exception: compressor building on a platform located offshore or in inland navigable waters.)
 - b) Compressor building must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property.
 - c) There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.
2. Building construction
 - a) Each building on a compressor station site must be made of noncombustible materials if it contains either
 - i) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or
 - ii) Gas handling equipment other than gas utilization equipment used for domestic purposes.
3. Exits
 - a) Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety.
 - b) Each door latch on an exit must be of a type which can be readily opened from the inside without a key.
 - c) Each swinging door located in an exterior wall must be mounted to swing outward.
4. Fenced areas
 - a) Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area.
 - b) Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be able to be opened from the inside without a key.



5. Electrical facilities

- a) Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI/NFPA 70, so far as that code is applicable.

Liquid removal

- 1. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.
- 2. Each liquid separator used to remove entrained liquids at a compressor station must:
 - a) Have a manually operable means of removing these liquids.
 - b) Where slugs of liquid could be carried into the compressors, have either air operated, automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and
 - c) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.
 - d) All liquid removal tanks that could contain combustible gas vapors must have a vent stack at a minimum of 8 feet above ground level.

Emergency shutdown

- 1. Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:
 - a) It must be able to block gas out of the station and blow down the station piping.
 - b) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
 - c) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:
 - i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
 - ii) Electrical circuits needed to protect equipment from damage may remain energized.
 - d) It must be operable from at least two locations, each of which is:
 - i) Outside the gas area of the station;
 - ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and



- iii) Not more than 500 feet (153 meters) from the limits of the station.
- 2. If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.
- 3. On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:
 - a) In the case of an unattended compressor station:
 - i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or
 - ii) When an uncontrolled fire occurs on the platform; and
 - b) In the case of a compressor station in a building:
 - i) When an uncontrolled fire occurs in the building; or
 - ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition².
- 4. Refer to procedure P-192.731(c) for additional information on emergency shutdown device inspection and testing.

Pressure limiting devices

- 1. Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent. (Refer to procedure P-192.731(a) for information on relief valve inspections.)
- 2. Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

Additional safety equipment

- 1. Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation must not be affected by the emergency shutdown system.
- 2. Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

² An electrical facility which conforms to Class 1, Group D, of the National Electrical Code is not a source of ignition



3. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.
4. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.
5. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

Ventilation

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.



Description	This procedure is used to properly design instrument, control and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	As needed
Reference	49 CFR 192.203 <i>Instrument, Control, and Sampling Pipe and Components</i> LA Title 43 Part XIII 1163 <i>Instrument, Control, and Sampling Pipe and Components</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	None (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

Design all instruments, control and sample piping, tubing and fittings to meet operating conditions and service by:

1. Constructing pipe, tubing, and fittings with adequate pressure and temperature ratings for maximum operating conditions of the equipment to which it is attached. The piping must be able to provide the physical strength and protection against vandalism or other damage. The following piping is to be used:
 - i) Schedule 80 pipe and forged steel (2000 lb.) fittings or
 - ii) Stainless steel tubing and fittings on control or supply lines.
2. Install a shutoff valve as near practicable to the takeoff point of each take off pipe or tubing run.
3. Do not use brass or copper material in high pressure or high temperature applications.
4. Equip piping or components in which liquids might accumulate with drains or drips and protect from freeze damage. Install strainers/filters if clogging from solids or deposits is a possibility.
5. Install piping, tubing, and components in a manner that protects them from stress or shear damage, outside force damage, and vibration damage.
6. Protect each control line from anticipated causes of damages and design and install them to prevent damage to any one control line from making both the regulator and over pressure protection device inoperative.
7. Make each join between pipe and valves or fittings, in a manner suitable for the anticipated pressure and temperature conditions. Do not use slip type expansion joints. Allowed for expansion by providing flexibility within the system itself.
8. Protect each control line from anticipated cause of damage and design and install them to prevent damage to any one control from making the regulator and over-pressure protective device inoperative.



Description	This procedure is used in conjunction with written welding procedures that have been destructively tested to ensure DOT pipelines are welded per DOT regulations.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.221	<i>Scope</i>
	49 CFR 192.225	<i>Welding – General</i>
	49 CFR 192.227	<i>Qualifications of welders</i>
	49 CFR 192.229	<i>Limitations on welders</i>
	49 CFR 192.231	<i>Protection from Weather</i>
	49 CFR 192.233	<i>Miter Joints</i>
	49 CFR 192.235	<i>Preparation for Welding</i>
	49 CFR 192.241	<i>Inspection and Test of Welds</i>
	49 CFR 192.243	<i>Nondestructive Testing</i>
	49 CFR 192.245	<i>Repair or Removal of Defects</i>
	49 CFR 192 Appendix C	<i>Qualification of Welders for Low Stress Level Pipe</i>
Reference (Cont'd)	49 CFR 192 Appendix C	<i>Qualification of Welders for Low Stress Level Pipe</i>
Forms / Record Retention	Construction Records	<i>Pipeline Construction Records</i>
	F-192.225	<i>Pipeline Welding Packet / Written Procedures and Records of qualified testing for the Life of the Pipeline</i>

¹ If the line is new, replaced, relocated or changed.



System (form not required if equivalent data is documented in construction records)

**Related
Specifications**

API 1104 *Welding of Pipelines and Related Facilities 20th Edition
(Including Errata/addendum (July 2007), and Errata 2
(2008) (API STD 1104, IB*

**OQ Covered
Task**

0801 *Welding*

(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Welding Procedures (192.225)

- a) All welding will be performed using qualified procedures or the new procedure will be qualified. All welding procedures will be qualified under section 5 of API 1104 as incorporated by reference in 49 CFR 192.7. The quality of the test welds used to qualify welding procedures shall be determined through destructive testing in accordance with the applicable welding standard(s). In addition, design drawings and specifications for the particular job must be met. The written procedure and all records of qualified testing will be retained for the life of the pipeline.
- b) If the procedure needs to be qualified refer to the Construction Manual: Joining of Pipes by Welding.
- c) No automatic welding equipment is used at this time. Procedure will be created if machine or automatic welding equipment utilized.

2. Welder Qualifications (192.227)

- a) If the pipeline operates at >20% SMYS, annually Welders must be initially qualified in accordance with section 6 of API Standard 1104 20th edition and recognized by PHMSA utilizing WTG specific welding procedures and documenting the qualifications on WTG's Weld Test Report. The second annual test the welder must successfully qualify in accordance with section 6 or section 9 of API Standard 1104 20th edition. These qualification tests cannot exceed 7 ½ months in a calendar year.
- b) If the pipeline will operate at a pressure <20% SMYS, welders may be qualified under Section I of Appendix C of 49 CFR 192.
- c) A welder qualified under an earlier edition than that listed in 49 CFR 192.7 may weld but not re-qualify under that earlier edition.
- d) These records must be maintained for five years following construction.

3. Limitations On Welders (192.229)

- a) If a welder's qualifications were based upon nondestructive testing, he may not weld on compressor station pipe and components.
- b) In order to weld with a welding process, the welder must have within the proceeding 6 months welded using that process.
- c) Welders Qualified under API Standard 1104:
 - i) Will not weld on pipe operated at a pressure that produces a hoop stress of 20% or more of SMYS unless within the preceding 6 calendar months that welder has had one weld tested and found acceptable under Sections 6, 9, or Appendix A of API Standard 1104 (See 49 CRF 192.7 for correct edition.)

NOTE: Welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year at intervals not exceeding 7 ½ months.



- ii) May not weld on pipe that will be operated at a pressure producing a hoop stress of less than 20% of SMYS unless the welder is tested according to "i" above or re-qualifies according to d(i) or d(ii) below.
- d) A welder qualified under 49 CFR Appendix C may not weld unless –
 - i) Within the preceding 15 months, but at least once each calendar year, he is requalified under Appendix C; or
 - ii) Within the preceding 7 ½ months, but at least twice each calendar year, he has had:
 - (1) A production weld cut out, tested and found acceptable in accordance with the qualifying test; or
 - (2) If he will weld only on service lines 2 inches or smaller in diameter, has had two sample welds tested and found acceptable in accordance with the test in section III of 49 CFR 192 Appendix C.
- 4. Protection From Weather (192.231)
 - a) Welding must be protected from weather conditions that would impair the quality of the completed weld.
- 5. Miter Joints (192.233)
 - a) A mitered joint on steel pipe that will be operated at a pressure that produces a hoop stress of 30% or more of SMYS may not deflect the pipe more than 3 degrees.
 - b) A miter joint on steel pipe that will be operated at a pressure that produces a hoop stress of less than 30%, but more than 10%, of SMYS may not deflect the pipe more than 12½ degrees and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
 - c) A miter joint on steel pipe that will be operated at a pressure that produces a hoop stress of 10% or less of SMYS may not deflect the pipe more than 90 degrees.
- 6. Preparation For Welding (192.235)
 - a) Before beginning to weld, ensure the weld surface is clean and free of any material that may be detrimental to the weld, and the pipe or component is aligned in a way that provides the most favorable condition for depositing the root bead.
 - b) Ensure that the alignment is preserved while the root bead is being deposited.
- 7. Inspection Of Welds(192.241)
 - a) Refer to procedure P-192.241 for details on performing visual inspection of welds.
 - b) Visual inspection is to be conducted by an individual qualified by appropriate training and experience. The inspection is to ensure that the weld is performed according to the written procedure and that the weld is acceptable under d below.
 - c) If the pipeline is to be operated at a pressure that produces a hoop stress of 20% or more of SMYS the weld must be nondestructively tested in accordance with procedure P-192.243. However, welds on pipe with a nominal diameter of less than 6 inches do not have to be nondestructively tested if they have been inspected and approved by a qualified



welding inspector. In addition, if the pipe is to be operated at a pressure that produces a hoop stress of less than 40% of SMYS and the welds are so limited that nondestructive testing is impractical, it is not required as long as they are visually inspected and accepted.

- d) The acceptability of a weld shall be determined in accordance with section 9 of API 1104 as incorporated by reference in 49 CFR 192.7 and recognized by PHMSA. However, if a girth weld is unacceptable under these standards for a reason other than a crack, and if Appendix A to API 1104 applies to the weld, the acceptability of the weld may be further determined under that appendix.
- e) Welds that are found unacceptable according to d above, must be removed or repaired according to procedure P-192.245.

8. Maintenance Welding

NOTE: Prior to welding on the pipe surface, adequate pipe wall thickness must be determined (by nondestructive methods) to prevent burn-through. See procedure P-192.243

- a) Prior to welding, the bevel of a joint of pipe shall be inspected for proper dimension, cleanliness and angle and the pipe shall be free of dirt and foreign materials.
- b) For in-service pipeline welding, the pipeline pressure at the location that welding is being done shall be limited to either:
 - i) 30% of the specified minimum yield strength for the pipe wall thickness and grade, or
 - ii) 50% of MAOP for those pipelines that have an established MAOP.
- c) If excessive scale or hydrocarbon build-up, or pipe wall lamination is found, notify Supervisor or Project Inspector immediately.
- d) The ends of a repair sleeve must be positioned a minimum of 6 inches beyond a damaged area (including internal corrosion).
- e) Supports or braces may only be welded directly to jurisdictional pipelines in accordance with 49 CFR 192.161.
- f) Electrodes used in maintenance welding of patches and sleeves shall be low hydrogen Type E7010, E8010, or E6010.
- g) Maintenance welding procedures are located in the Construction Manual.
- h) Each bead must be grinded and cleaned prior to depositing subsequent filler passes.
- i) Consideration must be given to ensure the carbon equivalent of the pipe being sleeved is less than 0.45%.

9. Records

- a) WTG will maintain records demonstrating compliance with this procedure. When construction data is not available from daily logs or other records, P-192.225 must be completed. All records must be retained for the life of the pipeline. Ensure all records are traceable, verifiable, and complete.



Description	The purpose of this procedure is to establish a method for visual inspections of welds.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) ¹ <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR192.241 LA Title 43 Part XIII 1321	<i>Inspection and Test of Welds</i> <i>Inspection and Test of Welds</i>
Forms	F-192.225	<i>Pipeline Welding Packet</i>
Related Specifications	API 1004	<i>Welding of Pipelines and Related Facilities</i> ASME Boiler Pressure Vessel Code (Section 9)
OQ Covered Task	0641 <i>Visually Inspect Pipe and Components Prior To Installation</i> (In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.) 0811 <i>Visual Inspection of Welding and Welds</i> (In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

1. Review job specifications and welder certifications prior to beginning work.
 - a) Review job specifications, materials list and other applicable documentation. The review should answer questions about the procedures to be used, electrodes, and the acceptance standards to be followed for welding. If there are any conditions or circumstances that need clarification, bring them up during a pre-job meeting.
 - b) Review the welding procedures to be used. Ensure the welding procedures are appropriate for the materials to be welded - the wall thickness, diameter ranges and electrodes allowed. Evaluate the pre-heat and post-weld heat treatment requirements.
 - c) Review the welder qualifications to ensure the welders are certified for the welding they will perform. Verify the expiration date, materials, sizes, position, direction, joint design and electrodes for which each welder is qualified. Ensure that they are qualified to perform the procedure that will be used.
2. Visually inspect pipe, bevels, fit-up, line-up clamps, etc.
 - a) Visually inspect each pipe joint interior, remove any foreign matter immediately prior to installation. Properly clean the ends of each joint of pipe prior to alignment and welding.
 - b) Ensure that reasonable precautions are taken to keep pipeline free from dust, dirt, debris, or any other foreign material while the work is being done. Nightcaps should be installed on open-ended pipe at the end of each workday. Ensure that the nightcaps are watertight when installed below grade. Support pipe in such a manner to assure the section will not endanger job site personnel and the coating will not be damaged due to expansion and contraction or any other pipe movement. Where possible, place pipe supports approximately 8 feet from each field girth weld.
 - c) Ensure the bevels, both internal and external, are made by machine tool or machine-oxygen cutting and they meet the dimensional requirements of the appropriate welding procedure specification(s). Ensure the welding surfaces uniform, free of fins, laminations tears, scale, slag, oil, grease, paint, dirt, moisture and any other foreign material that might adversely affect welding or weld quality.
 - d) For below and aboveground piping, ensure that welded pipe is aligned so that longitudinal seams will be located on the bottom quarters. Rotate successive joints of pipe so that longitudinal seams of two successive joints of pipe are not aligned with each other. Ensure that minimum separation between weld seams is 20°.
 - e) Ensure the longitudinal seams are not located at the 6 o'clock position on pipe supports and pipe straps.
 - f) Ensure proper alignment is achieved immediately prior to welding. When external alignment clamps are used, ensure 50% of the root pass has been deposited before the clamps are removed. When internal alignment clamps are used, ensure 100% of the root pass has been deposited before the clamps are removed. Exception: When welding in a bell hole or other tie-in situations, hold pipe movement to a minimum until the root pass and the hot pass are complete.



- g) Do not allow heating of the pipe to obtain proper alignment for welding.
- h) Hammering of the pipe to attain alignment is not permitted.

3. Monitor welding equipment and welding operations.

- a) Make the electrical ground contact point of a material grade not greater than that of the line pipe material. Securely attach the ground to the bevel or an existing weld in such manner to prevent arc bums. Make the contact area large enough to prevent local overheating or arcing between the contact. There can be no magnetic ground clamps or magnets of any kind on the pipe during welding.
- b) Use insulated electrode holders on fabrication, repairs, or tie-ins. There can be no arc strikes or dragging of electrodes on the surface of the work. Confine striking of arcs within the welding groove. Treat any arc bum on a finished weld that results in pitting or loss of weld metal in the same manner as an arc strike outside the welding groove.
- c) Ensure that the maximum time lapse between weld passes as outlined on the welding procedure specification is being followed. Exception: Complete tie-in welds and live-line welding without interruption once welding is started.
- d) Ensure that specific preheating requirements and temperatures as outlined in the approved welding procedure specification are being used. Other conditions may exist where preheating is required. Preheat using a propane torch or other approved method. Do not use oil burners - they are not permitted. Check preheating temperatures just prior to the start of welding by using temperature-indicating crayons, thermocouple pyrometers, or by other approved methods. Make sure the preheated area extends at least 3" on each side of the weld preparation and is uniform around the pipe circumference. Do not permit the temperature in the weld area to fall below the required preheat temperature at any time during the welding process. If welding is interrupted for any reason make sure the weld is preheated to the proper temperature before welding is resumed.
- e) Ensure that slag and remaining flux is removed from each weld pass by hand power tools prior to deposition of additional weld metal. Ensure visible defects such as slag cavities, cold laps, surface porosity, starts, stops, and high points are removed by grinding. Make sure that no two adjacent or successive weld beads are started or stopped at the same location.
- f) Backwelding shall not be permitted as a routine welding practice. Determine whether to allow back welding for fabricated assemblies and pipeline weld repairs. Approve suitable back-welding prior to use.
- g) Make sure that used welding rods are placed in an appropriate bucket and not discarded on the ground.

4. Visually inspect completed welds

- a) Inspect before, during, and after welding operations. Ensure that the completed weld is brushed and thoroughly cleaned before the weld is visually inspected. Make sure the completed weld has a uniform appearance around the entire pipe circumference and that the weld surface and surrounding area is free of weld spatter.



- b) Ensure that each weld meets standards of acceptability prescribed in API 1104 (latest DOT-approved edition), unless otherwise specified in the job specifications, contract or drawings. The welding inspector shall be responsible for the final decision on weld acceptability.
- c) Make sure the nondestructive testing requirements (see Procedure P-192.243) are met.
- d) Order the repair or replacement of each weld or portion thereof that does not meet the visual and/or nondestructive acceptability requirements of the applicable code in accordance with procedure P-192.245 Repair and Removal of Weld Defects. The repair shall meet the same acceptance requirements as the original weld.
- e) Document the completed weld on Form F-192.225.



Description	This procedure is used to non-destructively test a weld, pipe or component, by any process that clearly indicates any defects that may affect the integrity of the tie-in or component replacement.	
Regulatory Applicability	<p>Welds on a pipeline that will be operated at pressure that produces a hoop stress of 20% or more of SMYS unless the weld is visually inspected and approved by a qualified welding inspector and:</p> <ol style="list-style-type: none">1. The pipe has a nominal diameter of less than 6 inches; <p>or</p> <ol style="list-style-type: none">2. The pipeline is operated at a pressure that produces a hoop stress less than 40% of SMYS and there are such a limited number of welds that non-destructive testing impractical. <p>When nondestructive testing is required (see exceptions above), the following percentages of each day's field butt welds, selected at random by the operator, must be non-destructively tested over their entire circumference:</p> <ol style="list-style-type: none">1. At least 10% of welds in onshore Class 1 locations;2. At least 15% of welds in Class 2 locations;3. 100% of welds in Class 3 and 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, unless impracticable, which in case at least 90% must be tested. Non destructive testing must be impracticable for each girth weld not tested. <p>100% of welds at pipeline tie-ins, including tie-ins of replacement pipe.</p> <p>With the exception of a welder whose work is isolated from the principal welding activity, testing must include a sample of each welder's work each day.</p> <ul style="list-style-type: none"><input checked="" type="checkbox"/> Regulated Transmission Pipelines<input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A)<input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B)¹<input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Any time welding is performed on the pipeline, as required above	
Reference	49 CFR 192.241	<i>Inspection and Test of Welds</i>
	49 CFR 192.243	<i>Non-Destructive Testing</i>

¹ If the line is new, replaced, relocated or changed.



LA Title 43 Part XIII 1321	<i>Inspection and Test of Welds</i>
LA Title 43 Part XIII 1323	<i>Non-Destructive Testing</i>

Forms / Record Retention	F-192.225 <i>Pipeline Welding Packet / Life of Pipeline System (Procedure Steps #7)</i>
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Related Specifications	API 1104 <i>Welding of Pipelines and Related Facilities</i> ASME Boiler Pressure Vessel Code (Section 9)
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OQ Covered Task	0611 <i>NDT – Liquid Penetrant Testing</i> 0601 <i>NDT – Radiographic Testing</i> 0621 <i>NDT - Magnetic Particle Testing</i> 0631 <i>NDT – Ultrasonic Testing</i>
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(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Decide which NDT process to use. The process must clearly indicate defects that may affect the integrity of the weld.

NOTE: Trepanning may not be used. Guidelines for performing each type are located on the following page.

2. Obtain the written procedures for the test. The written procedure must be attached to form F-192.225. If the procedure needs to be qualified, use the appropriate section of F-192.225 to document the qualification. The procedure must have provisions for proper interpretation of the test to ensure the weld is acceptable under 49 CFR 192.241(c) (See procedure P-192.245).
3. Determine that the technicians have been trained on the procedures that are to be used. Document this verification on F-192.225.
4. Witness the results of the test for abnormal conditions or defects.
5. If the weld is found to be unacceptable follow procedure P-192.245 to repair or remove the weld defect.
6. Record all required data on F-192.225. Attach all supplemental data.
7. Retain for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects. This should be documented on F-192.225.

Radiographic (X-Ray) Inspection

Individuals performing x-ray inspection must be certified. Procedure should be developed according to industry certifications.

Ultrasonic Inspection

1. Prepare pipe surface.
 - a) Remove poly coating.
 - b) Clean surface.
2. Calibrate UT equipment according to manufacturer's specifications.
3. Use meter to get reading.
 - a) UT complete weld area.
 - b) Record reading.

NOTE: A detailed procedure that includes test result interpretation must be written and qualified prior to usage.

Magnetic Flux Inspection

Individuals performing magnetic flux inspection must be certified. Procedure should be developed according to industry certifications.



Dye Penetrant Inspection

1. 1) Select the appropriate dye penetrant.
2. 2) Coat the pipe surface under evaluation with the dye penetrant.
3. 3) Clean the excess dye penetrant from the surface of the pipe.
4. 4) Spray or dust the white powder developer on the surface of the pipe under evaluation.
5. 5) Conduct a visual inspection using white or ultraviolet light, identifying the visible or fluorescent dye indications.

NOTE: A detailed procedure that includes test result interpretation must be written and qualified prior to usage.



Description	This procedure is used to repair or remove welds that are found unacceptable under 49 CFR 192.241(c).	
Regulatory Applicability	All welds that are found to be unacceptable under 49 CFR 192.241(c) <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.245 <i>Repair or Removal of Defects</i> LA Title 43 Part XIII 1325 <i>Repair or Removal of Defects</i>	
Forms / Record Retention	F-192.225	<i>Pipeline Welding Packet / Life of Pipeline System</i>
Related Specifications	API 1104 <i>Welding of Pipelines and Related Facilities</i> ASME Boiler Pressure Vessel Code (Section 9)	
OQ Covered Task	0801	<i>Welding</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

Repair or Removal Requirements

1. With the exception of welds on offshore pipelines being installed from a pipeline vessel, each weld having a crack of more than 8% of its length must be removed.
2. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist that would adversely affect the quality of the weld repair.
3. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.
4. All repairs must be performed in accordance with written weld procedures that have been qualified under 49 CFR 192.225 (See procedure P-192.225.). Repair procedures must ensure that the minimum mechanical properties specified for the welding process used to make the original weld are met upon completion of the final weld repair.

NOTE: The procedures on the following pages should be used as guidelines, but the actual welding on the repairs / removals must be performed using qualified welding procedures according to procedure P-192.241.

Repair of Weld Defects Other than Cracks

1. Does the pressure in the pipeline provide a safe working condition at the location of the repair?
 - a) If yes, go to Step 2.
 - b) If no, reduce the pressure according to company guidelines before proceeding to Step 2.
2. Locate and mark the defect area to be repaired.
3. Will the repair of the defect require grinding the weld below the pipe surface?
 - a) If yes, go to Step 4 or 5 as appropriate.
 - b) If no, go to the section Repair Defects of a Cover Pass on a Weld Other than a Crack.
4. For butt welds:
 - a) Grind the cover pass(es) flush with the pipe surface and continue to grind a groove down through the weld metal until the defect is completely removed or until the remaining weld thickness is thin enough that a new bead will penetrate the defect area with sound weld metal.
 - b) Proceed to Step 6.
5. For fillet welds:
 - a) Grind as necessary to repair the weld, taking caution not to grind into the carrier pipe.
 - b) Reweld the ground-off area using a qualified procedure. The repair area should be uniform, blending with the adjacent weld metal in order to minimize stress concentrators.
 - c) Proceed to Step 6.



6. Prior to welding, preheat to a minimum of 200°F for a distance of approximately 3 inches on each side of the weld. The preheat temperature should be maintained during welding.
7. Weld the grooved area using a qualified welding procedure. The repair area should extend 1.5 to 2 inches past both ends of the defect area.
8. Inspect the repaired area using the same means used to detect the defect.
9. Does the repaired area meet the requirements of the inspection?
 - a) If yes, go to Step 10.
 - b) If no, refer to the appropriate section of the procedure Repair of a Previously Repaired Area or Replacement of a Weld or Cylinder of Pipe to cut out and replace the weld.
10. Document the repair. File the repair documentation according to company policy.

Repair Defects of a Cover Pass on a Weld Other than a Crack

1. Does the pressure in the pipeline provide a safe working condition at the location of the repair?
 - a) If yes, go to Step 2.
 - b) If no, reduce the pressure according to company guidelines before proceeding to Step 2.
2. Locate and mark the defect area to be repaired.
3. Will the repair require grinding (such as when repairing external undercut or pinholes)?
 - a) If yes, go to Step 4
 - b) If no, repair the defect (such as low or narrow cap) by recapping the weld in the defect area. Then go to Step 7.

NOTE: Preheat may be required if the weld has cooled.

4. Will the repair of the defect require grinding the weld below the pipe surface?
 - a) If yes, refer to the section Repair of Weld Defects other than Cracks.
 - b) If no, go to Step 5.
5. Grind the cover pass(es) flush with the pipe surface. (For fillet welds, grind as necessary as you repair the weld, taking caution not to grind into the carrier pipe).
6. Reweld the ground-off area. The repair area should be uniform, blending with the adjacent weld metal in order to minimize stress concentrators.

NOTE: Preheat may be required if the weld has cooled.

7. 7) Inspect the repaired area, using the same means used to detect the defect.
8. 8) Does the repaired area meet the requirements for inspection?
 - a) If yes, go to Step 9.
 - b) If no, refer to either the section of this procedure titled Repair of a Previously Repaired Area or go to the section Replacement if a Weld or Cylinder of Pipe to cut out and replace the weld.



9. Document the repair.
10. File the repair documentation according to company policy.

Repair or Removal of Butt Welds Containing Cracks

1. Does the pressure in the pipeline provide a safe working condition at the location of the repair?
 - a) If yes, go to Step 2.
 - b) If no, reduce the pressure before proceeding to Step 2
2. Locate and mark the defect area to be repaired. Is the crack less than 8% of the weld length?
 - a) If yes, go to Step 3.
 - b) If no, the entire weld must be cut out and replaced. Go to the procedure Replacement of a Weld or Cylinder of Pipe.
3. Grind the cover pass(es) flush with the pipe surface. Continue to grind a groove down through the weld metal until the crack is completely exposed and until the remaining weld thickness is thin enough that a new bead will penetrate the crack area with sound weld metal. Use magnetic particle or dye penetrant inspection to determine the exact position and pattern of the crack in the ground area.
4. Once satisfied that the entire crack has been exposed, preheat the repair area to a minimum temperature of 200°F for a distance of at least 3 inches each side of the ground-out area and at least 3 inches beyond each end of the ground-out area circumferentially. This temperature should be maintained throughout welding.

NOTE: A qualified crack repair procedure must be followed in Steps 5 through 9.

5. Weld a new root bead, obtaining full penetration through the crack area. Grind the root pass and weld a second pass in the same area to ensure that all evidence of the crack has been completely removed.
6. Grind the second pass smooth and perform magnetic particle or dye penetrant inspection again to locate any traces of a crack.
7. Are there any traces of a crack remaining?
 - a) If yes, repeat Steps 4 through 6.
 - b) If no, go to Step 8.
8. Check the preheat temperature and reheat if necessary. Weld the remaining passes and grind smooth.
9. Once the weld is completed and allowed to cool to ambient temperature, re-inspect the repaired area using the same means used to detect the defect.
10. Does the repaired area meet the requirements of the inspection?
 - a) If yes, go to Step 11.



- b) If no, refer to either the sub-task Repair of a Previously Repaired Area or go to sub-task Replacement of a Weld or Cylinder of Pipe to cut out and replace the weld.

11. Document the repair.

12. File the repair documentation according to company policy.

Replacement of a Weld or Cylinder of Pipe

1. Purge the isolated section of the line with air or nitrogen as appropriate.
2. Ensure that the pipe is adequately exposed according to company guidelines.
3. Obtain an adequate length of pretested pipe.
4. Excavate the line as appropriate for the product in the line according to company guidelines.
5. Turn off the closest upstream and downstream rectifiers.
6. Install jumper cable, attaching the jumper cable ends at points beyond the locations of final cuts.
7. Make rough cuts to remove section of pipe.
8. Remove the section of pipe.
9. Seal off the inside of each pipe end by use of expandable plugs, gas bags, or other sealing devices.
10. Ensure that the open ends are free of an explosive mixture. (Use a detection device appropriate to the welding procedures used).
11. Bevel and prepare pipe ends for welding according to the welding procedure to be used.
12. Remove the sealing devices used in Step 9.
13. Set the replacement pipe section in place and align pipe ends for welding by use of external lineup clamps.
14. Weld the replacement section of pipe into the adjacent pipe according to a qualified butt weld procedure appropriate for the pipe being welded.
15. Remove the jumper cable.
16. Inspect each weld by radiography in accordance with API Standard 1104.
17. Is the weld acceptable?
 - a) If yes, go to Step 18.
 - b) If no, repair the weld according to a qualified procedure. Repeat Step 16.
18. If used, remove the stoppling devices according to the stoppling procedure.
19. Install sandbag supports under each stopple fitting.
20. Apply proper coating to the welded areas and replacement section as necessary.
21. Turn on rectifiers that were turned off in Step 4.



22. If applicable, restore pressure to the isolated section of the line.
23. Notify appropriate operations personnel that the pipeline has been successfully repaired and is ready for service.
24. Document the repair.
25. File the repair documentation according to company policy.

Repair or Removal of Arc Burns

1. Does the pressure in the pipeline provide a safe working condition at the location of the repair?
 - a) If yes, go to Step 2
 - b) If no, reduce the pressure according to company guidelines before proceeding to Step 2.
2. Grind, file, and/or sand the arc burn area, blending it in with the contour of the pipe until visual evidence of the arc burn area is completely removed. (If grinding, check for pipe defects that affect the wall thickness in the area to be repaired before grinding.)
3. Etch the arc burn area with a 10–20% (by volume) solution of ammonium persulfate or 2% (by volume) solution of nital. (Note: The solution should be prepared by a person knowledgeable in the methods and hazards associated with mixing etching solutions.)
4. Visually inspect the arc burn area for consistent coloring. Is the area consistent in color?
 - a) If yes, go to Step 5.
 - b) If no, repeat Steps 2 through 4.
5. Rinse the arc burn area with water to dilute the etching solution and remove any residue from the pipe surface.
6. Use ultrasonic readings to determine the remaining pipe wall thickness in the area of the repair:
 - a) The minimum thickness required by the tolerances in the specification to which the pipe is manufactured (refer to API Specification 5L).
 - b) The minimum wall thickness for the design pressure of the pipeline (refer to 192.105(a)).
7. Does the remaining wall thickness of the repaired area meet the requirements?
 - a) If yes, go to Step 8.
 - b) If no, the entire arc burn area must be cut out as a cylinder. See “Replacement of a Weld or Cylinder of Pipe.”
8. Document the repair. File the repair documentation according to company policy.

Repair of a Previously Repaired Area

1. Does the pressure in the pipeline provide a safe working condition at the location of the repair?
 - a) If yes, go to Step 2.



- b) If no, reduce the pressure before proceeding to Step 2.
2. Locate and mark the defect area to be repaired.
3. Grind the cover pass(es) flush with the pipe surface. Continue to grind a groove down through the weld metal until the defect is completely removed and until the remaining weld thickness is thin enough that a new bead will penetrate the defect area with sound weld metal.
4. Preheat the repair area to a minimum temperature of 200°F for a distance of at least 3 inches each side of the ground-out area and at least 3 inches beyond each end of the ground-out area circumferentially. This temperature should be maintained throughout welding.
5. Weld the grooved area using a qualified welding procedure for a previously repaired area. The repair area should extend 1.5 to 2 inches past both ends of the defect area.
6. Once the weld is completed and allowed to cool to ambient temperature, re-inspect the repaired area using the same means used to detect the defect.
7. Does the repaired area meet the requirements of the inspection?
 - a) If yes, go to Step 8.
 - b) If no, repeat Steps 2 through 6 to repair this previously repaired area, or go to the section on Replacement of a Weld or Cylinder of Pipe to cut out and replace the weld.
8. Document the repair.
9. File the repair documentation according to company policy.



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Description	This procedure has been adopted to guide our employees and contractors on the steps necessary to produce threaded steel pipe connections that meet our company standards as well as State and Federal agencies having jurisdiction over these facilities.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input checked="" type="checkbox"/> Regulated LNG Facilities	
Frequency	As needed	
Reference	49 CFR 192.273	<i>General</i>
Forms / Record Retention	None	
Related Specifications	None	
OQ Covered Task	0721	<i>Joining of Pipe – Threaded Joints</i>
	(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

General

1. Only pipe meeting API 5 L specifications will be used in threaded connections.
2. Steel pipe 2" and larger, used to transport gas in a compressor station, will not be joined by a threaded connection.
3. Screw fittings used to join pipe must meet the same pressure/temperature rating specifications as the pipe.

Field Cut Threads

1. All field cut threaded joints must be joined to a "gas tight joint".
2. The following table will be used to ensure threaded connections meet pressure requirements:

Normal Pipe size	Outside Diameter	Standard (Schedule 40 Wall Thickness)	Min. Wall Thickness After Thread
½	0.840	0.109	0.065
¾	1.050	0.113	0.065
1	1.315	0.133	0.065
1¼	1.660	0.140	0.065
1½	1.900	0.145	0.065
2	2.237	0.154	0.075

3. Inspect the pipe threader before beginning and replace any thread dies or other parts that show signs of wear.
4. Place pipe to be threaded firmly into a pipe vise and tighten until it is firm.
5. Using a pipe cutter, cut the end of the pipe squarely and cleanly.
6. Remove any burrs from the cut end of the pipe using a reamer tool.
7. Select the die head according to the size and type of pipe you will be threading.
8. Place the die head over the pipe on the threader.



9. Maintain pressure on the die head, while also pushing the handle down to start the threader.
10. Maintain constant pressure on the handle throughout the threading process.
11. Apply threading oil generously while threading.
12. Stop threading when the end of the threading die is flat against the end of the pipe.
13. Reverse the ratchet mechanism and begin turning the die head in the opposite direction.
14. Stand the pipe on its end and gently tap to remove any burrs or particles that may be lodged within the pipe.
15. Clean the pipe with a dry cloth, removing all oil. Use wire brush to clean threaded end of pipe.

Joining of Pipe with Threaded Joints

1. Seal the threaded end of the pipe with approved Teflon tape and/or a pipe thread compound beginning one thread back from the end of the fitting.
 - a. If using tape, tightly wrap in the direction of the continuous threads in order to conform the tape to the shape of the threads with four to six wraps.
2. Thread the fitting onto the end of the threaded pipe until hand tight.
3. Tighten fitting about 4 turns past hand tight.
4. Test fittings for leaks using approved method.



Description These plastic pipe qualifications and joining procedures have been adopted to guide our employees and contractors on the necessary steps to select and produce plastic pipe and joints that meets standards of Facilities, as well as state and Federal Agencies having jurisdiction over these facilities.

All individuals joining plastic pipe must be qualified to perform that procedure.

**Regulatory
Applicability** ☒ Regulated Transmission Pipelines
☒ Regulated Gathering Pipelines
☒ Regulated Distribution Pipelines

Frequency Any time plastic pipe is to be joined

Reference 49 CFR 192.281 *Plastic Pipe*
49 CFR 192.283 *Plastic Pipe: Qualifying Joining Procedures*
49 CFR 192.285 *Plastic Pipe: Qualifying Persons to Make Joints*
49 CFR 192.287 *Plastic Pipe: Inspection of Joints*

**Forms / Record
Retention** None

**Related
Specifications** None

OQ Task	Covered	
	0671	Joining of Plastic Pipe – Solvent Cement
	0681	Joining of Plastic Pipe – Stab Fittings
	0751	Joining of Plastic Pipe - Butt Heat Fusion: Manual
	0761	Joining of Plastic Pipe - Butt Heat Fusion: Hydraulic Machine
	0781	Joining of Plastic Pipe – Electrofusion

(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program)



Procedure Steps

Design Specifications:

1. Only new polyethylene plastic pipe will be used in West Texas Gas's facilities for New Construction. It must be qualified for natural gas use by the manufacturer accordance with listed specifications, free from visible defects and is, resistant to gas, chemicals, and its environment.
2. The pipe must be manufactured and marked to the standard in accordance to ASTM D 2513 and marked every two feet and legible at time of installation to indicate the following:
 - a. Size
 - b. Material
 - c. Manufacturer
 - d. Pressure Rating
 - e. Temperature Rating
 - f. Type, grade, or model.
3. The design pressure may not exceed 100 psig for plastic pipe used in distribution systems and at class 3 and 4 locations.
4. Plastic pipe may not be used where operating temperatures are below -20 degrees F or above 100 degrees F.
5. The wall thickness for thermoplastic pipe may not be less than 0.062 inches. For reinforced thermosetting plastic pipe, the minimum wall thickness must meet the following table.

Nominal Size	Wall Thickness
2"	0.060"
3"	0.060"
4"	0.070"
6"	0.100"

6. Design pressure for thermoplastic, fittings must conform to ASTM D 2513.

When joining plastic pipe with a solvent cement, adhesive, or heat fusion, do not disturb the joint until it has properly set. Threaded or miter joints are not to be used on plastic pipe. Used plastic pipe should not be utilized for gas handling processes.

Types of Joints:

1. Solvent Cement Joints



2. Heat-fusion Joints
3. Mechanical Joints:

Qualifying Joining Procedures

1. Plastic pipe will not be joined by a threaded joint or by a miter joint.
2. A plastic pipe joint that is joined by solvent cement, adhesive or heat fusion may not be disturbed until it has properly set.
3. Prior to using tools/equipment used in joining plastic pipe, the operator must ensure the tool is within calibration dates and being used within the manufacturer's recommended practice.
4. All joints must be made following written procedures that have been proven by testing per the following testing requirements to produce strong gastight joints. These procedures must be qualified according to the following:

a) Heat fusion and solvent cement:

Before a procedure that has been written can be used to make these joints, it must be qualified by subjecting a specimen joint made using the procedure to the following tests:

- i. Burst test requirements of –
 - Paragraph 6.6, or 6.7 of ASTM D2513 (thermoplastic pipe). WTG will not install thermosetting plastic pipe.
 - Paragraph 9.1, 9.2, 9.3, or 9.4 of ASTM Designation F1055 (electrofusion fittings for polyethylene pipe and tubing)
 - ii. If the procedure is intended for lateral pipe connections, a specimen joint made from pipe sections joined at right angles according to the procedure will be subjected to a force on the lateral pipe until failure occurs in the specimen. Failure must initiate outside the joint area for the procedure to qualify.
 - iii. If the procedure is intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25% or failure initiates outside of the joint area, the procedure may be used.
- b) Mechanical joints - Before a procedure that has been written can be used to make mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:
- i) The apparatus for the test must be specified in ASTM D638 (except for conditioning).
 - ii) Ensure that the specimen is long enough that the distance between the grips or the apparatus and the end of the stiffener does not affect the joint strength.
 - iii) Test at a speed of 0.20 inches per minute, plus or minus 25%.
 - iv) Specimens less than 4 inches in diameter are qualified if the pipe yields to an elongation of no less than 25% or failure initiates outside of the joint area.



- v) Pipe specimens 4 inches in diameter and larger shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 degrees F or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.
- vi) Each specimen that fails at the grips must be retested using new pipe.
- vii) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material with a lesser wall thickness.
- c) A copy of each written procedure used for joining pipes must be available to the individuals making and inspecting the joints.
- d) WTG will not install pipe or fittings manufactured prior to July 1, 1980.

Qualifying Individuals to Make Joints

All individuals making plastic pipe joints must be qualified under the applicable procedures by appropriate training or experience in the use of the procedure and by making a specimen joint from pipe sections joined according to the procedures that passed inspection as described below:

1. The joint must be visually examined during and after assembly and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
2. In the case of heat fusion, solvent, cement or adhesive joints:
 - a) Tested under any of the test methods listed above applicable to the type of joint and material being tested; or
 - b) Cut into at least 3 longitudinal straps, each of which is:
 - i) Visually examined by the District Manager and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
 - ii) Deformed by bending 180 degrees, and if failure occurs, it must not initiate in the joint area
3. All personnel qualification records must be maintained for a minimum of five years following construction.

NOTE: A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

Qualification of Plastic Pipe Joiners

The District/Division Manager shall assure that all employees joining pipe have been qualified in accordance with procedures published by Energy Worldnet (EWN) The District Manager and local supervision will ensure all persons joining pipe will be qualified according to these procedures, and a record of qualified persons kept on file. Butt fusion joints will be visually inspected and tested in



accordance to ASTM F 2620 or an alternative written plan approved by WTG Vice-President of Operations.

Joining Plastic Pipe

Note: All materials and joints must comply with ASTM D 2513 requirements.

Each solvent cement joint on plastic pipe must comply with the following:

1. The mating surfaces of the joint must be clean, dry, and free of materials, which might be detrimental to the joint.
2. Use only primer with ASTM F 656 designation and solvent cement with ASTM D 2564 designation.
3. Use only PVC fittings marked ASTM D 2466 or ASTM D 2513.
4. Use only PVC pipe marked ASTM D 2513.
5. The joint may not be heated to accelerate the setting of the cement.

Each heat-fusion joint on plastic pipe must comply with the following:

1. Each heat fusion tool must be maintained and calibrated in accordance with the manufacturer's recommended practices.
2. A butt heat-fusion must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.
3. Heat may not be applied with a torch or open flame.

Solvent Cement Joints

1. Solvent Cement for PVC pipe and fittings
 - a) Primer
 - i. Primer is a special cleaner that will cut through and clean the dense surface of PVC pipe. Primer must be applied liberally and with a scrubbing motion.
 - b) Solvent Cement
 - i. Solvent Cement must be free flowing, contain no lumps, dissolved particles or any foreign matter that would affect the joint strength.
 - ii. Solvent Cement must not show gelatin, stratification, or
 - iii. Separation that cannot be removed by stirring. Keep container closed when not in use.
2. Safe Handling of Primer and Solvent Cement
 - a) Liquid solvent and their vapors contained in plastic pipe cement and primers are highly flammable. The solvents if improperly handled can cause personal injury. Follow these precautions when using primer and solvent cement.
 - i. Avoid prolonged breathing of solvent vapors when in closed areas.
 - ii. Keep solvent primers and solvent cement away from all sources of heat, sparks and open flame.



- iii. Container should be tightly closed except when the contents are being used.
- iv. Use eye protection when using these liquids. In case of eye contact flush with plenty of water for 15 minutes and seek medical attention.
- v. Wear protective gloves to protect hands when applying cement or primer.
- vi. Use soap and water to wash skin in case of contamination.

3. Joining Procedures

- a) Pipe ends to be joined must be cut square. Use a fine tooth saw and a miter box if necessary.
- b) Chamfer and deburr the cut ends. Failure to chamfer (bevel edge) the ends of the pipe will result in the softened plastic being deformed as the pipe is inserted into the socket. This results in a leaking joint.
- c) All surfaces to be joined must be clean and free of moisture. Use clean dry cloth to clean and dry mating surfaces.
- d) Measure and mark the socket depth of the fitting on the outside of the pipe. Use a soft point marker so as not to scratch the pipe surface.
- e) Apply primer and cements with a natural bristle brush. Use a ½" brush for small pipe. For pipe sizes larger than 2" use a brush width that is equal to ½ the pipe diameter. Keep the brush immersed in the primer or cement between applications. Keep cement container tightly closed when not being used. Discard the cement at the first sign of gelling.
- f) PVC solvent cement is fast drying and must be applied as quickly as possible. It may be necessary for two employees to perform this operation on larger diameter pipe, or when the temperature of the fittings and pipe is at or above 100 degrees F.
- g) Use a scrubbing motion to apply primer to inside of the socket surface to ensure penetration. Repeat application may be necessary to soften the surfaces to be joined. Next, soften the surface of the pipe end up to the previously marked socket depth. Do not soften any pipe surface that will not be covered by the socket. Apply solvent cement to the pipe end and a light coat of cement to the inside surface of the socket. Avoid excess cement in the socket. Time is important at this stage of the joining process. Apply a second coat of cement to the pipe end.
- h) Assembly of joint – Immediately after applying the last coat of cement to pipe insert the pipe into the socket. Turn the pipe ¼ turn during assembly (but not after the pipe is fully bottomed) to distribute the cement evenly. Insert pipe with a steady even motion.
- i) Assembly must be completed within 20 seconds after the last application of cement. On larger size pipe two employees or mechanical forcing equipment may be needed to hold the pipe in place for one minute after assembly. Do not disturb or apply any force to joints. The joint can be destroyed by early rough handling.
- j) After assembly – Wipe excess cement from the pipe at the end of the socket fitting. A properly made joint will show a bead of cement around its entire perimeter. Any gaps indicate a defective joint that must be cut out and replaced.
- k) Cure Time - Handle assembled joints carefully until the cement has completed the cure period. See the following table for cure times.
 - 1. 30 minutes minimum at 60 to 100 degree F
 - 2. 1 hour min. at 40 to 60 degree F
 - 3. 2 hour min. at 20 to 40 degree F



4. 4 hour min. at 0 to 20 degree F
4. Testing PVC Joints
 - a) Pressure test on PVC piping and jointing will be conducted the same as testing procedures of plastic as outline in P-192.501.
5. Other Requirements
 - a) Tracer wires, tapes, or cable present on the system for locating purposes must be repaired if damaged after completion of all joining and before backfilling.

Heat Fusion – Butt Joints

General

This procedure has been qualified according to procedures published by the pipe manufacturer and as outlined in the Minimal Federal Safety standards for Pipelines Transporting Natural Gas.

Application

This procedure can be used for all systems and class locations that operate less than 100 psi.

Procedures

1. Process: Heat Fusion
2. Material: Polyethylene
3. Diameter: ¾" thru 6"
4. Joint Type: Butt Fusion
5. Joining:
 - i. Proper precautions need to be taken in a gaseous atmosphere to prevent an accidental ignition.
 - ii. Clean each pipe with clean cloth. Do not use synthetic or treated cloths.
 - iii. Square each end of pipe to be fused.
 - iv. Check line-up of pipe ends. Adjust for high or low.
 - v. Check heater temperature – should be 400-450 degrees F.
 - vi. Insert heater plate between pipe ends and bring ends firmly into contact with plate, but do not apply pressure, achieve a melt bead of 1/16" to 1/8" depending on pipe size.
 - vii. Remove heater plate and bring melted ends together. Apply only enough pressure to obtain a double roll back bead.
 - viii. Allow the joint to cool at least 30 seconds before removing pressure

Heat Fusion – Electrofusion

All electrofusion joining processes will be made using the equipment and techniques that are recommended by the fittings manufacturer.



Repair of Plastic Pipe

Each imperfection or damage, such as crushes, gouges or grooves that would impair the serviceability of plastic pipe must be cut out and replaced.

Inspection of Joints

All individuals inspecting joints must be qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure and approved by the District Manager after proper training on visual examination of joints.



Description	This procedure is used to visually inspect all pipe and/or other components during construction or repair to ensure the components are not damaged in a manner that could impair their strength or reduce the pipe's serviceability.
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Regulatory Applicability	All pipe and components being installed/replaced <input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines
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Frequency	As needed
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Reference	49 CFR 192.63	<i>Marking of Materials</i>
	49 CFR 192.121	<i>Design of Plastic Pipe</i>
	49 CFR 192.301	<i>Scope</i>
	49 CFR 192.303	<i>Compliance with Specifications or Standards</i>
	49 CFR 192.305	<i>Inspection – General</i>
	49 CFR 192.307	<i>Inspection of Materials</i>
	49 CFR 192.313	<i>Bends and Elbows</i>
	49 CFR 192.315	<i>Wrinkle Bends in Steel Pipe</i>
	49 CFR 192.317	<i>Protection from Hazards</i>

Forms / Record Retention	F-192.305	General Inspection Report / Life of Pipeline System
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Related Specifications	API 1104	<i>Welding of Pipelines and Related Facilities</i>
	ASME Boiler Pressure Vessel Code (Section 9)	<input type="checkbox"/>



OQ Covered Task	0211	<i>Measure and Characterize Mechanical Damage on Installed Pipe and Components</i>
	0811	<i>Visual Inspection of Welding and Welds</i>
	1331	<i>Damage Prevention Inspection During Third Party Excavation or Encroachment Activities as Determined Necessary by Operator</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Check components and consumables upon receipt.
 - a) Ensure that they are marked properly:
 - i) Each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured. However, thermoplastic fittings must be marked in accordance with ASTM D2513. Markings may also indicate size, material, manufacturer, pressure rating and temperature rating. Also, type, grade and model as appropriate.
 - ii) Surfaces of pipe and components that are subjected to stress from internal pressure may not be field die stamped.
 - iii) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
 - iv) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.
 - b) Verify that the material received is marked as shown on the purchase document and that the material received is what was ordered. Review the documentation and verify that information agrees with purchase document requirements and material markings. Only items which meet or exceed the purchase document requirements are to be accepted by the receiving location.
 - c) Maintain the purchase document number and any other appropriate identification markings on the material in a manner that does not damage the material so that the marking remains visible until the material is installed. Review markings as necessary.
 - d) Cross reference mill test reports and fitting certification papers with the purchase order number. All steel pipe must have mill test reports when received and all fittings and other components must have certifications.
2. Visually inspect all pipe and components at the site to ensure that they are not damaged in a manner that could impair their strength or reduce serviceability.
3. Plastic pipe used in new construction must meet the criteria established in 49 CFR 192.63 and 49 CFR 192.123.
 - a) Each valve, fitting, length of pipe and other component must be marked with its manufacturing standard, or, in the case of thermoplastic fittings, to the standards of ASTM D2513-87. All pipe must also be marked indicating size, material, manufacturer, pressure and temperature ratings, type, grade and model.
 - b) All plastic pipe installed must meet the design limitations set forth in 49 CFR 192.123, including standards for temperature and pressure limitations.
 - c) All installed radius fittings will meet or exceed the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.
4. Ensure welding is done in accordance with a qualified written procedure and procedure P-192.225.



5. Ensure welds are done according to procedure. This inspection must be conducted according to procedures P-192.241 and/or P-192.243 by a qualified inspector.
6. Ensure that the welder is shielded from weather related conditions that can impair the weld.
7. Inspect to ensure each component is provided with protection against external corrosion per procedures P-192.455 and P-192.461. Ensure that the coating has not been damaged. If damage has occurred, the coating must be repaired or replaced prior to covering the pipe.
8. Visually inspect entire length of exposed pipeline to ensure there are no wrinkles, gouges or other apparent physical damage.
9. Ensure each field bend in steel pipe complies with the following:
 - a) Does not impair the serviceability of the pipe.
 - b) Wrinkle bend are not made on steel pipe that will be operated at a pressure that produces a hoop stress of 30 or more, of SMYS.
 - c) Does not have any sharp kinks.
 - d) When measured along the crotch of the bend, the wrinkles are a distance of at least one pipe diameter.
 - e) On pipe 16" or larger diameter, the bend does not have a deflection of more than 1 ½ percent for each wrinkle.
 - f) Has a smooth contour and is free from buckling, cracks, or any other mechanical damage.
 - g) On pipe containing a longitudinal weld, it must be as near as practicable to the neutral axis of the bend unless:
 - h) Is made with an internal bending mandrel; or
 - i) The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.
 - j) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.
 - k) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that 2" or more in diameter unless the arch length, as measured along the crotch, is at least 1".
 - l) No Bend shall have a difference between the maximum and minimum diameters in excess of 2.5 percent of the nominal diameter.
10. Ensure all pipe installed in a ditch is installed in a manner that minimizes secondary stresses and the possibility of damage to the pipe.
 - a) Inspect the ditch to ensure materials capable of damaging the coating are not present.
 - b) Identify and remove foreign objects that could cause damage to the pipeline system.
 - c) Ensure backfilling is done in a manner that protects the pipe coating and provides support for the pipe.



- d) Inspect backfill material before and during operations to prevent damage to pipeline.
- 11. Ensure buried pipe is provided with adequate cover per 49 CFR 192.327 and there is appropriate clearance between the pipe and underground structures per 49 CFR Part 192.325. (See Procedure P-192.325.)
- 12. Ensure pipe at each railroad and highway crossing is installed to adequately withstand the dynamic forces exerted by the anticipated traffic loads.
- 13. Ensure valves are accessible to authorized employees and are protected from damage and tampering.
- 14. Complete all applicable forms, gather all construction records (mill specs) and file. These are to be retained for the life of the pipeline.



Description	This procedure provides guidance for excavation, installation and backfilling to prevent damage to all pipelines including service lines.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	<div>49 CFR 192.319 <i>Installation of Pipe in a Ditch</i></div> <div>49 CFR 192.321 <i>Installation of Plastic Pipe</i></div> <div>49 CFR 192.325 <i>Underground Clearance</i></div> <div>49 CFR 192.327 <i>Cover</i></div> <div>49 CFR 192.329 <i>Installation of plastic pipelines by trenchless excavation</i></div> <div>49 CFR 192.361 <i>Service Lines: Installation</i></div> <div>49 CFR 192.363 <i>Service Lines: Valve Requirements</i></div> <div>49 CFR 192.365 <i>Service Lines: Location of Valves</i></div> <div>49 CFR 192.367 <i>Service Lines: General Requirements for Connections to Main Piping</i></div> <div>49 CFR 192.371 <i>Service Lines: Steel</i></div> <div>49 CFR 192.375 <i>Service Lines: Plastic</i></div> <div>49 CFR 192.379 <i>New Service Lines Not in Use</i></div> <div>49 CFR 192.381 <i>Service Lines: Excess Flow Valve Performance Standards</i> WTG P.192.605(b)(9) <i>Trench Safety</i></div> <div>WTG P-192.243 <i>Non-Destructive Testing of Welds</i></div> <div>WTG P-192.501 <i>Steel Pipeline Pressure Test Requirements</i></div> <div>WTG P-192.513 <i>Plastic Pipe Pressure Test Requirements</i></div> <div>OSHA 1926.651(c)(2) <i>Specific Excavation Requirements</i></div>	
Forms / Record Retention	WTG-1400 Project Report / Life of Pipeline	



**Related
Specifications**

None

**OQ Covered
Task**

0301	<i>Manually Open & Close Valves</i>				
0311	<i>Adjust & Monitor Flow or Pressure / Manual Valve Operation</i>				
0641	<i>Visually Inspect Pipe & Components Prior to Installation</i>				
0811	<i>Visually Inspections of Welding & Welds</i>				
0861	<i>Installation of Steel Pipe in a Ditch</i>				
0871	<i>Installation of Steel Pipe in a Bore</i>				
0901	<i>Installation of Plastic Pipe in a Ditch</i>				
0911	<i>Installation of Plastic Pipe in a Bore</i>				
0941	<i>Installation of Tracer Wire</i>				
0951	<i>Installation of Above Grade Pipe</i>				
0971	<i>Installation and Maintenance of Casings, Spacers, Vents & Seals</i>				
0981	<i>Backfilling</i>				
1341	<i>Provide</i>	<i>Or</i>	<i>Assure</i>	<i>Adequate</i>	<i>Pipeline Support</i>
	<i>During</i>	<i>Operator</i>	<i>Initiated</i>	<i>Excavation</i>	<i>Activities</i>

(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

NOTE: Lowering or relocating a main or lateral of a piping system under pressure will not be permitted unless a written plan is submitted and approved by senior management.

Prior to Excavating

1. Refer to your state specific Damage Prevention Plan located at www.westtexasgas.com for WTG approved procedures regarding excavation and damage prevention.
2. Refer to (P-192.605(b)(9) Trench Safety and P-192.69 Storage and Handling of Pipe
3. Ensure pipe is placed on padded blocks, wedges, etc to prevent movement during the fitting and welding process.
4. Inspect all equipment to be used such as side booms, track hoes, backhoes, rollers, calipers, lifting devices, etc for any defects that could harm the pipe.
5. Ensure that the trench is stable and can withstand vibration from heavy machinery.
6. If pipeline will encroach any underground facility, P-192.325 must be reviewed.

Installation of Plastic Pipe

1. Prior to beginning work in the trench and on a periodic basis while work is being performed, test the air in the trench with a certified CGI for concentrations of a combustible gaseous atmosphere which could cause an oxygen deficient atmosphere.
2. Visually inspect ditch.
 - a) Make sure the ditch is free of rocks and/or debris that can damage the pipeline.
 - b) Verify proper depth and width of the ditch.
 - c) Ensure that the ditch is padded and levelled properly to give good support to the pipe as well as not to add any stress to the line.
3. Lower piping and tracer wire into ditch in a manner that minimizes stress to the pipe.
4. In the event of installation by trenchless excavation
 - a) Ensure sufficient clearance from all other underground utilities and/or structures to allow for installation and maintenance activities going forward.
 - b) Utilize device or method (weak link) to protect the plastic pipe and components from excessive force and exceeding the maximum tensile stress during the pulling process.
5. Pressure test according to WTG P-192.513 for plastic.



Installing Steel Pipe

1. Prior to beginning work in the trench and on a periodic basis while work is being performed, test the air in the trench with a certified CGI for concentrations of a combustible gaseous atmosphere which could cause an oxygen deficient atmosphere.
2. Visually inspect ditch. Make sure the ditch is free of rocks and/or debris that can damage the pipeline.
 - a) Verify proper depth and width of the ditch.
 - b) Ensure that the ditch is padded and levelled properly to give good support to the pipe as well as not to add any stress to the line. For trenches with significant amount of rock, the bottom of the trench shall be padded with sand or other approved padding material. Recommendation of 6" of soft padding shall be in place on the bottom of the trench to prevent projections damaging the pipe or coating.
 - c) A rock shield can be used to line the ditch and/or wrap the pipe during installation to prevent coating damage.
 - d) Protective shields shall be placed along the trench walls to prevent damage to the coating during lowering-in if necessary. The shields shall be removed only after the pipe is in place and subject to no further movement.
3. Welds must be X-Rayed according to WTG P-192.243 and coated prior to installation.
4. Coating must be jeeped prior to lowering into ditch and holidays repaired.
5. Install pipeline into the ditch in a manner that minimizes stress to the coating. After lowering pipe into the ditch make sure that there is adequate support. If needed use sandbags and padding dirt.

Prior to Backfilling

1. Ensure the pipe in the ditch has adequate support. If needed use sandbags and padding dirt.
2. Ensure that there is adequate sidewall clearance for proper compaction.
3. Check that desired depth identified below is met.
4. Ensure that initial backfill material is free of rocks and debris capable of damaging coating or pipe. Use sand if needed.
5. If applicable, run gauge plate pig to ensure no damage has occurred and that there are no foreign objects in pipe.
6. Pressure test according to WTG P-192.501 for steel or WTG P-192.513 for plastic



Backfilling

1. Initial Backfilling

- a) Prior to initial backfill, ensure that all damage to the protective coating and wrapping has been repaired before allowing the pipeline to be backfilled.
- b) Prior to initial backfill, ensure the pipe is adequately supported along its entire length to avoid undue stresses and backfill material does not include any stones, rock or other material which may damage the pipe or the coating.
- c) The best backfill material shall be used as soft surround for the installed pipe. Carefully place this material around the pipe and thoroughly compact until the level is 8 inches above the crown of the pipe across the full width of the trench.

2. Final Backfill

- a) The remaining excavated material of suitable quality, together with any imported material, shall be returned to the trench. The backfill material shall be heaped up along the trench line to leave a crown of 8-12 inches above adjacent ground level unless otherwise specified in the job plan.
- b) Remove surplus excavated subsoil, if any, from site or spread over the right-of-way on exposed subsoil. Do not spread surplus subsoil on topsoil.

3. Provide erosion protection if necessary.

- a) On steep slopes or any other sections of the pipeline subject to erosion where there is danger of the backfill being washed out of the trench, place sandbags in position prior to backfilling.
- b) Provide diversionary furrows if necessary to direct the flow of water into natural drainage courses and away from the pipeline trench.

4. Support against Settlement

- a) Where the pipeline emerges above ground, take special care to ensure that the buried section of the pipeline is adequately supported against settlement.

5. Backfilling of Made Roads, Footpaths and Paved Areas

- a) Backfill across highway and road cuts shall be made with selected moist backfill material which is placed in layers, thoroughly compacted by mechanical tamping unless otherwise specified in job plan.
- b) Verify that compaction has been achieved by testing crossing to permit or agreement.

6. Backfill in Irrigation and Draining Areas

- a) After backfilling the pipe trench across irrigated fields, make furrows across the backfill crown and pipeline right-of-way to maintain or reinstate the flow of irrigation or drainage water into its normal flow pattern.
- b) Where the sides of drainage or irrigation ditches are cut by the pipe trench, the ground shall be backfilled and suitably compacted so as to provide a good bond between the undisturbed sides of the drainage or irrigation ditch and the new backfill material.



7. Ensure each buried Transmission Line is provided with adequate cover.

Transmission Table Class Location:	Normal soil	Consolidated rock
Class 1 locations	30"	18"
Class 2, 3, and 4 locations	36"	24"
Drainage ditches of public roads and railroad crossings	36"	24"

(See regulations for exceptions)

8. Ensure each buried Distribution main line is provided with adequate cover.
- Except as provided in paragraph (b) of this section, each buried main line must be installed with at least 24 inches of cover.
 - Where an underground structure prevents the installation of a line or main with the minimum cover, the line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
9. Upon the completion of backfilling and cleaning up of work site, transmission lines will be subject to an above ground indirect assessment. This assessment will be performed to identify areas of coating damage incurred during the lowering and back filling process. These assessments can be accomplished by Alternating Current Voltage Gradient (ACVG) or Direct Current Voltage Gradient (DCVG) surveys or other technology. Other technologies must be approved by PHMSA per CFR 192.18 paragraph (g). **This requirement does not apply to gas gathering nor gas distribution mains.**

Installation of Service Lines

Note: Disconnected service lines that are being reinstated must be tested in the same manner as new service lines. Service lines that are temporarily disconnected from the main must be tested from the point of disconnection to the service line in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as installation of a bypass, any part of the original service line used to maintain continuous service does not have to be tested.

1. Ensure service lines are installed as follows:
- With at least 12 inches of cover on private property and at least 18 inches of cover in streets and roads. Note: If an underground structure prevents installation at these depths, the service line must be able to withstand any anticipated external loads.
 - Properly supported on undisturbed or well-compacted soil, and the backfill that is free from materials that could damage the pipe or its coating.



- c) If condensate in the gas might cause interruption in the gas supply to the customer, the service line is graded to drain into the main or into drips at the low points in the service line.
 - d) Minimize anticipated piping strain and external loading.
 - e) WTG will not install a service line through the outer foundation wall of a building.
 - f) WTG will not install a service line under a building.
 - g) Nonmetallic service lines that are not encased are provided with a means for locating them that complies with 49 CFR 192.321(e) (tracer wire installed).
 - h) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic pipe must be closed before insertion. In steel casing, plastic pipe must have spacers installed to prevent future damage from friction or pipe movement between the two materials.
- 2. Ensure that each service line has a service-line valve that meets the applicable requirements of 49 CFR 192 Subpart B and D. Note: Valves incorporated in meter bars, which allow the meter to be bypassed, are not to be used as service-line valves.
 - a) This valve may not be a soft seat service line valve if its ability to control the flow of gas could be adversely affected by exposures to anticipated heat.
 - b) Each service-line valve on a high-pressure distribution line, installed aboveground or in an area where the blowing of gas would be hazardous, the valve must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.
- 3. Valves are to be located as follows:
 - a) Service-line valve upstream of the regulator or upstream of the meter if there is no regulator.
 - b) For new construction or replacement of a service line post April 14, 2017, when the installation of an EVF is not feasible, a curb valve will be installed unless the installation would add an inherent safety risk. If underground service valves are installed, they will be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service line. All valves will be maintained consistent with all valve manufacture's specifications.
 - c) Installation of the curb valve, EFV or the justification of the inherent safety risk will be documented on the Project Completion Report.
- 4. Ensure the following requirements are met for connections to main piping:
 - a) Located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.
 - b) Each compression type service line to main connection must.
 - i. Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and



- ii. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and
 - iii. If service line is connected to a plastic main, a connecting fitting that provides a seal plus resistance to pullout (Category 1) is installed.
- 5. Ensure steel service lines that are operated at less than 100 psi are still constructed of pipe that is designed for a minimum of 100 psi.
- 6. Ensure that plastic service lines installed outside a building are underground unless:
 - a) Risers are installed in accordance with 49 CFR 192.321 and 192.204; and
 - b) The line can terminate above ground level and outside the building if:
 - i. The above ground level part is protected against deterioration and external damage.
 - ii. It is not used to support external loads.
 - iii. Has a minimum wall thickness in accordance with 49 CFR 192.121.
 - iv. Tracer wire installed.
 - v. The riser portion of the service line meets the requirements of 49 CFR 192.204
- 7. Ensure that services lines that are constructed but not placed in service comply with one of the following until the customer is supplied with gas:
 - a) The valve that is closed to prevent the flow of gas to the customer has a locking device or other means designed to prevent the opening of the valve by individuals other than those authorized by Company.
 - b) A mechanical device or fitting that will prevent the flow of gas will be installed in the service line or in the meter assembly.
 - c) The customer's piping is physically disconnected from the gas supply and the ends sealed.
- 8. Ensure excess flow valves (EFV) meet the following requirements:
 - a) If used in a single residence service line that operates continuously throughout the year at a pressure greater than 10 psi gauge, it must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification to ensure the valve:
 - i. Functions properly up to the maximum operating pressure it is rated.
 - ii. Functions properly at all temperatures reasonably expected in the operating environment it is installed.
 - iii. At 10 psi gauge:
 - (1) It will close at or not more than 50% above the rated closure flow rate specified by the manufacturer; and
 - (2) Upon closure, reduce gas flow.



- (a) No more than 5% of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour if the valve is designed to all pressure to equalize across the valve; or
 - (b) No more than 0.4 cubic feet per hour if the valve is designed to prevent equalization of pressure across it.
- iv. Does not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.
- b) Meets the applicable requirements of 49 CFR Subpart B-Materials and D-Design of Pipeline Components.
- c) Its presence is marked or otherwise identified in the service line.
- d) Is located as near as practical to the fitting connecting the service line to its source of gas supply.
- e) Is not installed in a service line where there has been prior experience with contaminants in the gas stream if they could be expected to cause the valve to malfunction or where it would interfere with necessary operation or maintenance activities on the line, such as blowing liquids from the line.
- f) An excess flow valve (EFV) installation must comply with the performance standards in §192.381. The operator must install an EFV on any new or replaced service line after April 14, 2017, that services:
 - i. A single service line to one Single Family Residence (SFR).
 - ii. A branched service line to a SFR installed concurrently with the primary SFR service line (*i.e.*, a single EFV may be installed to protect both service lines).
 - iii. A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV.
 - iv. Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and
 - v. A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.
- g) Unless one or more of the following conditions is present, then an EFV is not required:
 - i. If the service line operates at a pressure less than 10 psig.
 - ii. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer.
 - iii. An EFV could interfere with necessary operations or maintenance activities.
 - iv. An EFV meeting the performance standards in CFR 192.381 is not commercially available.



Description	This procedure is used to determine the minimum clearance between existing pipe(s) and other underground structures installed by excavation, boring, or directional drilling.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) ¹ <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.325 <i>Underground Clearance</i> LA Title 43 Part XIII 1725 <i>Underground Clearance</i>	
Forms / Record Retention	Update maps as necessary F-192.614 <i>Damage Prevention / 5 Years</i> F-192.709 <i>Repair Work Order / Life of Pipeline System</i> WTG 1100 <i>Exposed Pipeline Inspection / 5 Years</i> WTG 1101 <i>Leak Report Form / Life of Pipeline System</i>	
Related Specifications	API 1104 <i>Welding of Pipelines and Related Facilities</i> ASME Boiler Pressure Vessel Code (Section 9)	
OQ Covered Task	CT0861 <i>Installation of Steel Pipe in a Ditch</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	

¹ If the line is new, replaced, relocated or changed.



Procedure Steps

1. Determine the method of installation for the WTG pipe or foreign structure being installed.
 - a) If structures are in an open trench, go to Step 6).
 - b) If foreign structure is installed by directional drilling or boring, go to Step 2).
2. Contractor is responsible to determine depth of the company pipeline at the location in question. Using methods approved by WTG:
 - a) Search records and maps for pipeline information.
 - b) Expose pipeline by spot excavations.
 - c) Hydrovac
3. When WTG is crossing foreign facilities work with representatives of facilities to determine depth of the foreign pipeline or structure.
4. Compare depths of the two structures to determine clearance.
5. Go to Step 18).
6. Verify excavation is safe to enter.
7. Measure distance between the pipeline and the nearest foreign structure.
8. Inspect condition of exposed pipeline.
 - a) If steel pipe or coating is not damaged or faulty, go to Step 13).
 - b) If steel pipe or coating is damaged or faulty, go to Step 9).
 - c) If plastic pipeline has been damaged, repair per O&M procedures.
9. Remove coating for pipe inspection.
10. Inspect pipe for damage.
 - a) If pipe damage is not found, go to Step 13).
 - b) If pipe damage is found, go to Step 11).
11. Measure damage and notify supervisor of damage and its extent.
12. Repair coating and/or pipe per WTG O&M.
13. To determine if clearance is adequate, refer to Procedure P-192.319.
14. Install Test Station as instructed by company standards for CP interference purposes.
15. Inspect support and span of exposed pipe and foreign object.
16. Ensure the support is adequate to maintain clearance during and after backfilling.
17. Secure or ensure the responsible party secures the perimeter of excavation if to be left open and unattended.



18. Approve the excavation for backfilling by notifying supervisor, local job foremen, or others as appropriate.
19. Complete exposed pipe report or other forms required by West Texas Gas O&M.



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Description	The purpose of this procedure is to give the minimum requirements for installing customer meters, service regulators, and service line valves.	
Regulatory Applicability	<input type="checkbox"/> Regulated Transmission Pipelines <input type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input type="checkbox"/> Regulated LNG Facilities	
Frequency	As needed	
Reference	49 CFR 192.351	<i>Scope</i>
	49 CFR 192.353	<i>Customer Meters and Regulators: Location</i>
	49 CFR 192.355	<i>Customer Meters and Regulators: Protection from Damage</i>
	49 CFR 192.357	<i>Customer Meters and Regulators: Installation</i>
	49 CFR 192.359	<i>Customer Meter Installations: Operating Pressure</i>
	49 CFR 192.383	<i>Excess Flow Customer Notification</i>
	49 CFR 192.385	<i>Manual Service Line Shut-off Valve Installation</i>
	49 CFR 192.725	<i>Test Requirements for Reinstating Service Lines</i>
Reference (Cont'd)	LA Title 43 Part XIII 1901	<i>Scope</i>
	LA Title 43 Part XIII 1903	<i>Customer Meters and Regulators: Location</i>
	LA Title 43 Part XIII 1905	<i>Customer Meters and Regulators: Protection from Damage</i>
	LA Title 43 Part XIII 1907	<i>Customer Meters and Regulators: Installation</i>
	LA Title 43 Part XIII 1959	<i>Customer Meter Installations: Operating Pressure</i>
	LA Title 43 Part XIII 1933	<i>Excess Flow Customer Notification</i>
	LA Title 43 Part XIII 2925	<i>Test Requirements for Reinstating Service Lines</i>
	165 OAC Chapter 20-5-35	<i>Restrictions on Connections to Consumers</i>
Forms / Record Retention	None	



**Related
Specifications**

None

**OQ Covered
Task**

1161 Installation of Customer Meters and Regulators – Residential and Small Commercial

1171 Installing Customer Meters – Large Commercial and Industrial

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Customer Meters and Regulators

1. Ensure customer meters and regulators are located as follows:
 - a) Installed in a readily accessible location and protected from corrosion or other damage; including vehicular damage, if installed outside a building; vehicular damage that may be anticipated. Note that an upstream regulator in a series may be buried.
 - b) If installed in a building, service regulators need to be as near as practical to the point of service line entrance.
 - c) Customer meters will not be installed within a building.
 - d) Upstream regulators in a series must be located outside the building unless it is located in a separate metering or regulating building.
2. Ensure customer meters and regulators are protected from damage by:
 - a) Installing a device to protect against vacuum or back pressure situations.
 - b) Terminating service regulator vents and relief vents outdoors with the outdoor terminal being:
 - i) Rain and insect resistant
 - ii) Located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and
 - iii) Protected from damage caused by submergence where flooding may occur.
 - c) Ensure that each pit or vault that houses a customer meter or regulator at a place where vehicle traffic is anticipated is able to support the traffic.
3. Ensure customer meters and regulators are installed:
 - a) To minimize anticipated stresses upon the connecting piping and the meter.
 - b) If using close all-thread nipples, the wall thickness remaining after the threads are cut meets the requirements of minimum wall thickness in 49 CFR 192.
 - c) Connections are not made of lead or other easily damaged material.
 - d) If the regulator may release gas during operation, it is vented to the outside atmosphere.
4. Ensure the following operating pressure limits are followed:
 - a) Meter is not used at a pressure that exceeds the manufacturer's recommended case rating.
 - b) Newly installed meters manufactured after November 12, 1970, has been tested to a minimum of 10 psi gauge.
 - c) Rebuilt or repaired tinned case meters are not used at a pressure that is more than 50% of the pressure used to test the meter after rebuilding or repairing.



Oklahoma Pipelines

The following restrictions are applicable to pipeline connections to consumers in Oklahoma:

1. The system will be maintained in such a condition that will enable it to furnish safe and adequate gas service, subject only to emergency conditions beyond WTG control;
2. House piping will conform to the requirements of the applicable city or town ordinances. In towns, villages, and suburban territory where there are no applicable regulations as to gas service, house piping, and venting, WTG will comply with the Standards for the Installation of Gas Appliances and Gas Piping, as set forth in the National Fire Protection Associations No. 54, dated 1969, and future amendments or supplements thereto. WTG may decline to serve a consumer or prospective consumer until he has complied with all applicable State and municipal regulations governing gas service.
3. Residential customer meters designed for above ground use will not be buried or installed in any manner which would cause the surface of the shell of the meter to directly contact the ground.
4. All gas supplied to a consumer will be substantially free of impurities which may cause corrosion of mains, piping, and consumer's appliances, or form corrosive or harmful fumes when burned in a properly designed and adjusted burner.



Description

This procedure gives the steps to use when installing cathodic protection systems.

**Regulatory
Applicability**

The following PHMSA regulated pipelines –

- Converted under 49 CFR 192.14 – Must meet the requirements of 49 CFR 192.457 and all other applicable requirements within 1 year of the pipeline being readied for service. However, the requirements of 49 CFR 192.455 apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment that is replaced, relocated or substantially altered.
- Regulated onshore gathering – If the pipeline existed on April 14, 2006, but was not previously subjected to 49 CFR, and any onshore gathering line that becomes a regulated onshore gathering line under 49 CFR 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:
 - The requirements for corrosion control specifically applicable to pipeline installed before August 1, 1971, apply to the gathering line regardless of the date was actually installed; and
 - The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
- Buried or submerged pipelines installed after July 31, 1971 unless they meet an exception as outlined in 49 CFR 192.455
- Buried or submerged pipelines installed before August 1, 1971 – If the line has an external coating it must be cathodically protected along the entire area that is effectively coated.

Note: Buried piping at compressor, regulator, and measuring stations are exempt from this requirement.

- Except for cast iron or ductile iron pipe, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with 49 CFR Subpart I only in areas where active corrosion is found. ("Active corrosion" is defined as continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.)
 - Bare or ineffectively coated transmission lines;
 - Bare or coated pipes at compressor, regulator, and measuring stations;
 - Bare or coated distribution lines.

Note: West Texas Gas will determine the areas of active corrosion, pursuant to P-192.465(e), by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other



effective means, documented by data substantiating results and determinations.

Cathodic protection is not required in areas where active corrosion is not found in pipelines installed before August 1, 1971.

- ☒ Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☒ Regulated Gathering Pipelines (Type B)
- ☒ Distribution Pipelines

Frequency	As needed after pipe repair, replacement, or to mitigate corrosion
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Reference	49 CFR 192.452	<i>How Does This Subpart Apply to Converted Pipelines and Regulated Onshore Gathering Lines?</i>
	49 CFR 192.453	<i>General</i>
	49 CFR 192.455	<i>External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971</i>
	49 CFR 192.457	<i>External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971</i>
	49 CFR 192 Appendix D	<i>Criteria for Cathodic Protection & Determination of Measurements</i>
	16, TAC Rule 8.203 Supplemental Regulations	
	LA Title 43 Part XIII 2103	<i>How Does This Subpart Apply to Converted Pipelines and Regulated Onshore Gathering Lines?</i>
	LA Title 43 Part XIII 2105	<i>General</i>
	LA Title 43 Part XIII 2107	<i>External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971</i>
	LA Title 43 Part XIII 2109	<i>External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971</i>

Forms / Record Retention	F-192.455	<i>Installation of Cathodic Protection System / Life of Pipeline System</i>
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**Related
Specifications**

NACE RP-769-2002 *Control of External Corrosion on
Underground or Submerged Metallic
Piping Systems*

**OQ Covered
Task**

0081 *Install Cathodic Protection Electrical Isolation Devices*

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Steel Pipelines:

Each buried or submerged pipeline installed prior to August 1, 1971, that has an effective external coating, must be protected against external corrosion.

- This is not required on the following locations unless areas are found where active corrosion is found the following must be cathodically protected:
 - Bare or ineffectively coated transmission lines
 - Bare or coated distribution lines
 - Bare or coated pipes at compressor, regulator, and measuring stations

Each buried or submerged pipeline installed after July 31, 1971 must be protected against external corrosion, including the following:

- It must have an external protective coating meeting the requirements of §192.461
- It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion on construction.

NOTE: If West Texas Gas can demonstrate through tests, investigation or experience in the area of application, including as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist; the pipeline is not required to have external corrosion control. Each test, investigation, or experience used when determining cathodic protection systems is not required must be backed by documented proof to substantiate results and determinations. However, within 6 months of this decision, West Texas Gas will conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet, and soil resistivity measurements at potential profile peal locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive environment exists, the pipeline must be cathodically protected.

When a condition of active external corrosion is found on a pipeline installed before August 1, 1971, positive action will be taken to mitigate and control the effects of the corrosion. Schedules will be established for application of corrosion control. Monitoring effectiveness will be adequate to mitigate and control the effects of the corrosion prior to it becoming a public hazard or endangering public safety. See Procedure P-192.465(a) for cathodic protection monitoring.

The cathodic protection system must be evaluated, designed, installed and maintained by persons qualified through training and experience, and who will utilize the following sources of information to evaluate and design a cathodic protection system:

- Soil resistance studies along the pipeline route.
- Electrical surveys of the unprotected pipeline.
- Areas of electrical interference.



- Areas with foreign pipelines crossing.
- Areas requiring electrical isolation.
- Soil areas along the pipeline route that might contain corrosive elements.¹

Plastic Pipelines

Normal construction and repair practices post January 22, 2019 does not include the installation of metallic fittings below grade. In the rare event of circumstances that the only method of installation or repair of the pipeline would include a metallic fitting below grade, notification to the Compliance Department is required and the following criteria is required:

- An anode of appropriate size must be installed unless the metallic fitting can be:
 - WTG can prove by test, investigation or experience the metallic fitting has adequate corrosion control within the alloy composition and the fitting is designed to prevent leakage caused by localized corrosion pitting. This information must be recorded and place into the project file.
 - The corrosion control method must be documented in writing and the document placed within the project file.

NOTE: Aluminum may not be installed in a buried or submerged pipeline if exposed to an environment with a natural pH in excess of 8.

Required Level of Cathodic Protection

The amount of protection must be controlled so as to not damage the coating or pipe. Any cathodic protection system required to be installed must meet one of the following criteria:

1. A negative voltage of at least 850 millivolts, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied.
2. A negative voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied. This applies to structures not in contact with metals of different anodic potentials.
3. A minimum negative polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay.
4. A voltage at least as negative as the originally established voltage at the beginning of the Tafel segment of the E-log-I curve.



5. A net productive current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

Interpretation of Voltage Measurement

Voltage (IR) drops other than those across the structure / electrolyte boundary must be considered for valid interpretation of the voltage measurements in #1 and #2 above.

Reference Half Cells

Except as provided below, negative (cathodic) voltage must be measured between the structure surface and a clean saturated copper-copper sulfate half cell contacting the electrolyte.

Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to 850 millivolts as referred to a saturated copper-copper sulfate half cell.

1. Saturated KCL calmel half cell : - 780 millivolts
2. Silver-silver chloride half cell used in sea water: - 800 millivolts.

In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate cell is established.

Ground Beds

Follow these steps to install ground beds for cathodic protection.

1. Excavate line.
2. Surface Beds:
 - a) Remote:
 - i) Install vertically or horizontally between 5 and 15 feet deep on 10- or 15-foot centers between anodes approximately 400 feet away from pipeline.
 - b) Distributed:
 - i) Locate in close proximity to structure. Anodes should be located 5 to 10 feet away from the structure.
3. Deep Beds:
 - a) Shallow well anodes:
 - i) Install in vertical hole.
 - ii) Drill hole depths according to company and manufacturer standards.
 - iii) Install anode singular or multiple stacked according to company needs.
 - iv) Install coated or high-silicon iron anodes.
 - b) Deep well anodes:



- i) Install in vertical drilled holes.
- ii) Drill hole depths according to company and manufacturer standards.

Drilling and completion procedures must comply with local and state regulations.

- 4. Backfill with carbonaceous backfill, or backfill with removed soil if prepackaged anodes have been used.
- 5. Test for the presence of AC/DC current interference. Potential sources include, but are not limited to, other pipeline cathodic protection facilities, DC Traction systems (subways, light rail systems, trolleys, etc.), high voltage AC transmission lines, welding facilities, stray currents, etc. Install bonds according to the following section as applicable.

Bonds

Follow these steps to install bonds for cathodic protection.

- 1. Conduct joint cooperative interference tests with personnel representing the affecting structure to determine location of current discharge and magnitude of interference current.
- 2. Install cathodic wire leads on structure being adversely affected at location of current discharge.
- 3. Install cathodic wire lead on structure receiving current at a convenient location.
- 4. Cathodic test wires are to be attached by thermite weld (Cadweld, Thermoweld, etc.), brazing or other method that will yield a permanent, low-resistance connection. This must be done by a qualified individual using a written procedure.
- 5. Terminate cathodic wires from both structures inside a single test box that is accessible to both structures.
- 6. Inside of the test box, install shunts for measurement of current flow. Also install resistors as required to limit current interchange between the structures.
- 7. Install blocking diodes as required.
- 8. Conduct tests to determine effectiveness of the installed interference bond.
- 9. Install rectifiers or reverse current switches in unusual situations where a conventional metallic bond is not effective. This installation must be done by a qualified person.

Anodes

Follow these steps to install anodes for cathodic protection.

- 1. Select the proper size anode according to amount of pipe to be protected and the soil conditions. A pound of magnesium can protect 3860 square inches of bare metal pipe.
 - a) A guide to selecting anodes for coated pipelines is provided below. However, the dielectric strength of the coating, soil resistivity, square feet of pipe being protected and the desired life of the anodes should also be considered.



Service Rises and etc.	1 lb.
Short, small diameter service lines and etc.	5 lbs. to 9 lbs.
Sections of mains, space for adequate coverage	17 lbs.
Sections of Mains in low resistance soils spaced for adequate coverage	32 lbs.

- b) Pipe-to-soil readings should be taken before and after anode installation, so that the pipeline meets the criteria for protection as described above.

2. Galvanic Anodes – Determine the most suitable location for anode installation.

- a) Excavate anode hole at least four feet from the pipeline and at the same or greater depth of the pipeline to be protected.
- b) Install anode by placing in horizontal position and perpendicular to the pipe.

NOTE: Do not lift or lower the anode by its lead wire.

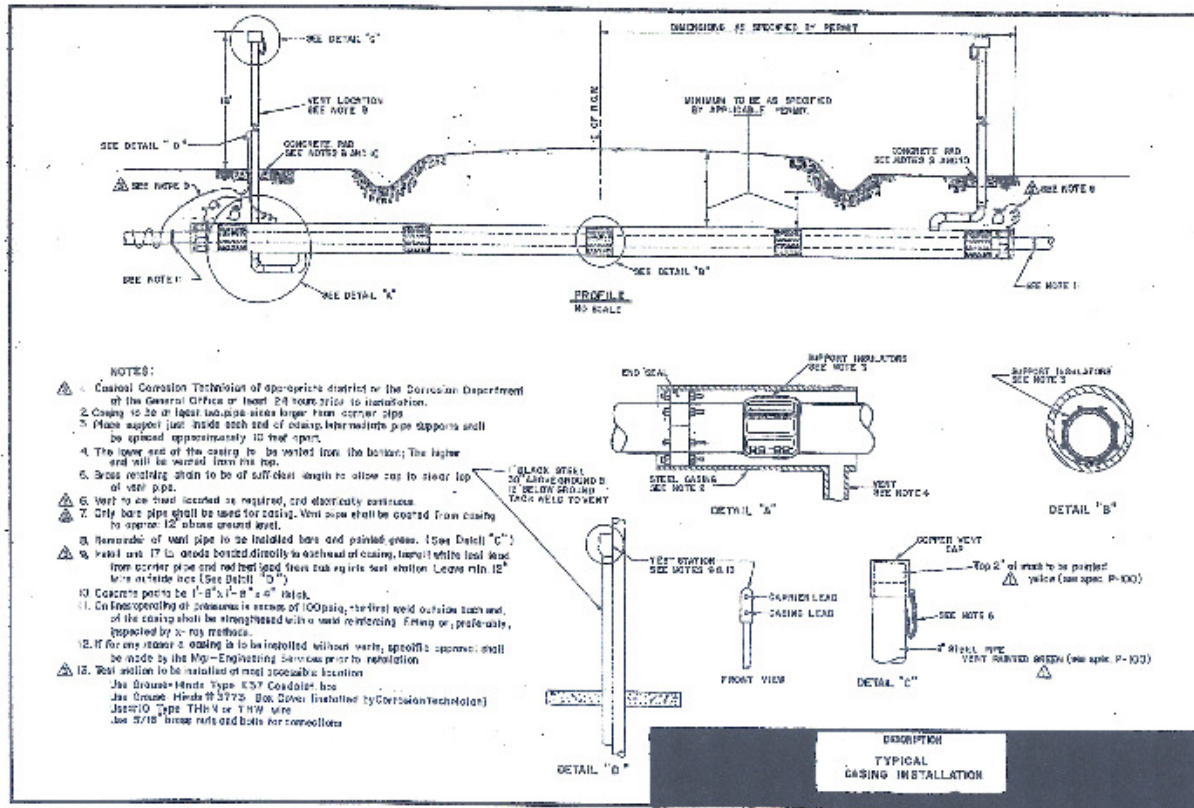
- c) Use care to protect the connection of the lead to the anode as even a small crack in the coating can allow moisture penetration leading to failure.
- d) Bury at sufficient depth to protect against accidental damage.
- e) Wet down anode prior to backfilling.
- f) Uncoil anode pigtail and extend fully, being careful not to damage or kink wire.
- g) Backfill carefully with native soil backfill. Use rock-free backfill to pad anode and the anode lead wire.
- h) Use care not to damage the coating of the lead wire.

3. Impressed Current Anodes

- a) Determine location of anode installation.
- b) Excavate vertical hole or horizontal ditch for anode installation.
- c) Carefully install anode(s) in excavated hole. Do not lift or lower an anode by its lead wire.
- d) Use care to protect the connection of the lead to the anode as even a small crack in the coating can allow moisture penetration leading to failure.
- e) Bury at sufficient depth to protect against accidental damage.
- f) Surround anode with coke breeze. For vertically augured holes, bring coke breeze level up to just under ground surface level if a vent pipe is not installed, to make a porous path for off-gassing to occur.

- g) Backfill with native soil. Use rock-free soil to pad the anode and the lead wire, being careful not to damage either.
- h) Use care not to damage the coating of the lead wire.

Figure 1. Typical Casing Installation





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Description	This procedure is designed to establish a standard program of examination of exposed metallic pipe for evidence of external corrosion.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	Any time buried pipe is exposed
Reference	49 CFR 192.459 <i>External Corrosion Control: Examination of Buried Pipeline When Exposed</i> LA Title 43 Part XIII 2111 <i>External Corrosion Control: Examination of Buried Pipeline When Exposed</i>
Forms	F-WTG-1100 <i>Exposed Pipeline Inspection / 5 Years</i> F-WTG-1400 <i>Project Report Form / Life of Pipeline System</i>
Related Specifications	None
OQ Covered Task	0151 <i>Visual Inspection of Buried Pipe and Components When Exposed</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Visually inspect exposed pipe for coating damage. Complete the appropriate form.
2. Tap the coating with a blunt object to ensure the coating is adhered to the pipe.
3. If the coating has been removed or has deteriorated, inspect the outer surface of the pipe for external corrosion and physical damage.
4. Measure wall thickness of pipe in areas with corrosion.
5. If corrosion requiring corrective action is found, investigate circumferentially and longitudinally beyond the exposed portion to determine if there is additional corrosion requiring remedial action in the vicinity.
6. Inspect the internal surface if pipe is cut per Procedure P-192.475(b).
7. Take remedial action as necessary according to procedure P-192.483.



Description	This procedure gives the steps required to apply and repair external coating.
Regulatory Applicability	<p>All DOT pipelines that are constructed, relocated, modified, replaced, including short segments replaced, will be coated. Pipelines that are converted to Part 192 service under 192.14 will be coated if relocated, replaced or substantially altered.</p> <p><input checked="" type="checkbox"/> Regulated Transmission Pipelines</p> <p><input checked="" type="checkbox"/> Regulated Gathering Pipelines</p> <p><input checked="" type="checkbox"/> Regulated Distribution Pipelines</p>
Frequency	As needed when a new pipeline is constructed or an existing pipeline is relocated, replaced or otherwise changed. This procedure may also be used after the pipeline coating has been damaged or a piece of pipe has been replaced. This should be done just prior to lowering the pipe into the ditch or submerging the pipe.
Reference	49 CFR 192.461 <i>External Corrosion Control: Protective Coating</i>
Forms / Record Retention	Document coating type with pipeline specifications
Related Specifications	None



**OQ Covered
Task**

-
- | | |
|------|--|
| 0991 | Coating Application and Repair: Brushed or Rolled |
| 1001 | Coating Application and Repair: Sprayed |
| 1011 | External Coating Application and Repair – Wrapped |
| 1021 | Apply or Repair Internal Coating Other Than by Brushing, Rolling or Spraying |

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Steel pipe that is to be buried must be coated to protect against corrosion. Weld joints, damaged areas, short sections of pipe, and buried fittings will have to be coated in the field.

1. Identify section to be coated.
2. Identify existing coating type, if previously coated.
3. Determine type of coating to be applied. Coating must:
 - a) Be designed to mitigate corrosion of the buried or submerged pipe and components
 - b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture
 - c) Be sufficiently ductile to resist cracking
 - d) Have enough strength to resist damage due handling (including but not limited to transportation, installation, boring and backfilling) and soil stress
 - e) Support any supplemental cathodic protection; and
 - f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
 - g) In the event the application of external coating is on a segment of a repaired or replacement that results in 1000' or more of backfill, within six months WTG will perform the same style of in directed assessment to ensure there was no damage to the integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons. WTG must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under this paragraph. WTG must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. WTG must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dB μ V for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits. WTG must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions.
4. Obtain the necessary tools, materials, and safety equipment.
5. If pipeline was previously coated, remove damaged coating on existing pipe.
6. Prepare surface for coating application according to coating manufacturer's specification.
7. Examine the pipe for evidence of corrosion, pitting, gouges, dents or other surface damage prior to applying coating.
8. Does the pipe surface have any of these damages that require further investigation?



- a) No: Continue with Step #9
 - b) Yes: Seek assistance from appropriate personnel for additional investigation and corrective actions before applying coating.
9. Apply coating according to vendor/manufacture specifications.
10. When applying the wrap:
- a) Pipe wrap tape and primer must be from the same manufacturer and approved for use with each other. Coating wrap should be minimum thickness of 35 mils.
 - b) The wrap must have sufficient adhesion to the material surface to effectively resist under film migration of moisture. It must be sufficiently ductile to resist cracking and have sufficient strength to resist damage due to handling and soil stress.
 - c) Coat the exposed steel with sufficient primer making sure to leave no voids in coverage. Primer must extend beyond tape one inch.
 - d) Let dry until tacky.
 - e) Tape wrap should extend no less than six inches onto existing coating on either side of weld area, repair, or replacement.
 - f) Wrap uphill, 50% overlap with no wrinkles.

Fusion Bond Epoxy Coatings:

Fusion Bond Epoxy coatings may be used for field joints, tie-ins, below ground fabrications, bore joint coating, and rehabilitation of existing pipelines. These products may be applied manually using brushes, rollers or by spraying using approved equipment. Strict manufacturer's instructions shall be followed pertaining to cleaning of materials to be coated, mixing and application of the product, regulating and inspecting the thickness of the application, and cure times due to changing conditions. Project inspectors will make sure that all equipment used in this process meets manufacturer's guidelines and all contract personnel and company personnel have the proper equipment and training to check material thickness either before curing (wet test) or after the material is cured (dry test).

Petrolatum Tape Installation:

Installation of petrolatum products should be limited to odd shaped buried pipeline components such as valves, flanges, service tee connections, and other applications that could be subject to voids in the coverage that would allow water or other impurities to collect on the pipe or component surface. When using these products strict attention shall be paid to manufacturer's instructions.



Roskoat/Mastic Coatings:

Roskoat/Mastic type coatings may be used for coating on exposed pipelines where repairs have been made to existing facilities. This type of coating should never be used on new construction, or on typical girth welds, and should be reserved for applications where wrapping the piping or components is not an option. All piping to be coated should be cleaned to bare metal with scrapers and power tools until all soil, rust, scale, and oil are removed. Care should be taken that all surfaces are coated with an even layer of material and allowed to dry and cure before backfilling.

Roskoat/Mastic coatings can be very damaging to plastic products and should never be allowed to accidentally come into contact with plastic piping as it can cause failures.

Coating Testing

All lengths of pipe shall be inspected for holidays in the coating prior to installation in the field as the pipe is lowered into the ditch. This may be accomplished by jeeping the pipe at the job site.

1. Equipment

Coating inspection shall be made with an approved (pulse type) holiday detector (jeep) having a voltage range of 1,000 - 14,000 volts.

2. Inspection Voltage

Required test voltages for various fusion-bonded coating thicknesses and for coal tar coating are as illustrated in the table below.

- a) Improper high voltage may damage the pipe coating.
- b) Improper low voltage settings will not provide valid testing.



Required Test Voltages For FUSION-BONDED Coating Thicknesses			
Coating Thickness (Mils)	Test Voltage	Coating Thickness (Mils)	Test Voltage
10	1,600	15	2,000
11	1,800	16	2,000
12	1,800	20	2,250
13	1,800	25	2,500
14	2,000	30	3,000
Required Test Voltage For COAL TAR Coating			
93.75	12,000	-	-

3. Equipment Check

- Test the energy source (battery) for proper voltage output. Refer to manufacturer's instructions.
- Connect the exploring electrode and grounding cable to the terminal of the detectors.
- Switch the detector to the "On" position.
- Touch the exploring electrode to the ground cable alligator clip. The instrument signal should actuate in accordance with the instrument manufacturer's operating instructions.
- If the instrument signal actuates, the instrument is ready to be calibrated. If it does not actuate, consider it defective and contact the manufacturer for repair.
- Full-circle wire-type spring electrodes shall be used for testing pipe sizes 3 inch and larger.
- Full-circle or half-circle wire-type spring electrodes may be used on 2-inch diameter pipe.
- Brush-type electrodes made of conductive rubber or half-circle spring electrodes shall be used for testing pipe 1 inch and 1 1/4 inch in diameter.

4. Equipment Calibration

- The detector shall be calibrated to the specified voltage to be used before each initial daily use. It shall be recalibrated periodically during the day.
- Connect a high-voltage voltmeter between the probe and ground lead.
- Switch the detector to the "On" position.
- Compare the voltage of the voltmeter with the output voltage of the detector.



- e) Switch the detector to the "Off" position and adjust to the specified voltage, if necessary.

CAUTION: Detector shall be in the "Off" position before making any changes in the voltage setting or connecting or disconnecting the voltmeter leads.

- f) Switch the detector to the "On" position.
- g) Again, compare the voltage of the voltmeter with the output voltage of the detector.
- h) Switch the detector to the "Off" position and disconnect the voltmeter.
- i) The instrument is now ready for use.

5. Testing Procedure

- a) The pipe to be inspected shall be grounded from the bare end of the pipe to the earth. When individual joints of pipe are being tested, each joint shall be individually grounded.
- b) If moisture exists on the coating surface, it shall either be removed or the surface shall be allowed to dry prior to conducting the test. Moisture on the coating surface can cause erroneous indications.
- c) Make contact with the detector electrode on the bare pipe end to verify that the instrument is properly grounded. This test shall be done each time a new section of coated piping is tested.
- d) For applications requiring a spring-type electrode, use a single pass, moving the electrode over the surface of the dry coating at a rate of approximately 1 foot per second.
- e) For applications requiring a brush-type or half-circle electrode, a pass on each side of the pipe 180° apart is required.
- f) As defects are identified, mark the location so repairs can be made upon completion of jacking and prior to installation.



Description	This procedure ensures cathodic protection is adequate.	
Regulatory Applicability	<p>Applies only to pipelines required to be cathodically protected under applicable regulations.</p> <p><input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines</p>	
Frequency	<p>Once per calendar year at intervals not to exceed 15 months.</p> <p>However, if tests at these intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10% of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10% checked each subsequent year, so that the entire system is tested in each 10-year period.</p>	
Reference	49 CFR 192.455	<i>External Corrosion Control: Pipeline installed after July 31, 1971</i>
	49 CFR 192.457	<i>External Corrosion Control: Pipeline installed before August 1, 1971</i>
	49 CFR 192.463	<i>External Corrosion Control: Cathodic Protection</i>
	49 CFR 192.465	<i>External Corrosion Control: Monitoring</i>
	16 TAC Rule 8.203	<i>Supplemental Regulations</i>
Forms / Record Retention	WTG 1203	<i>Cathodic Protection / Life of Pipeline System</i>
Related Specifications	None	



**OQ Covered
Task**

- | | |
|------|--|
| 0001 | Measure Structure-to-Electrolyte Potential |
| 0011 | Conduct Close Interval Survey |
| 0021 | Measure Soil Resistivity |
| 0031 | Inspect and Monitor Galvanic Ground Beds/Anodes |
| 0061 | Inspect or Test Cathodic Protection Bonds |
| 0071 | Inspect or Test Cathodic Protection Electrical isolation Devices |

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

NOTE: Refer to procedure P-192.483 for needed remedial actions.

Use the following as appropriate to determine the level of the cathodic protection on the pipeline. All Cathodic Protection voltage surveys will be conducted using a copper/copper sulfate half-cell will be connected to a quality digital voltmeter with an internal resistance of at least 10 Megohms (NACE standard).

Persons performing cathodic protection surveys should be aware that:

- Test points must be selected that will give a representative pipe-to-soil reading.
- Test points only over or near anode locations are not considered representative.

NOTE: Refer to procedure P-192.455 to determine if the cathodic protection is adequate and procedure P-192.483 for needed remedial actions.

Measure Pipeline-to-Soil Potentials, DC

Test points (electrode locations) used when taking pipe-to-soil readings shall be selected to give representative pipe-to-soil readings. Test points over or near an anode or anodes are not, by themselves, considered to be representative readings.

1. Bring proper equipment: Hi-impedance voltmeter; Copper-copper sulfate reference electrode (half-cell) and Test leads
2. Properly locate the half-cell relative to the structure.
3. Measure pipeline-to-soil potential by connecting the voltmeter's positive lead to the pipeline and the negative (common) lead to the half-cell. Use the DC voltage scale. Use of digital multi-meter preferred.
4. Document readings in appropriate format. Use Form WTG-1203, or cathodic data gathering software.
5. Field-analyze readings to ensure that they meet one of the following criteria as allowed in 49 CFR 192 Appendix D:
 - a) A negative voltage of at least 850 millivolts, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied.
 - b) A negative voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied. This applies to structures not in contact with metals of different anodic potentials.



- c) A minimum negative polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined by interrupting the protective current and measuring polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay.
 - d) A voltage at least as negative as the originally established voltage at the beginning of the Tafel segment of the E-log-I curve.
 - e) A net productive current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.
6. Promptly notify appropriate personnel if readings do not fall within desired range.
7. Forward all results to appropriate personnel for interpretation.

Measure Pipeline-to-Soil Potentials, AC

- 1. All steps are the same as for measuring pipeline-to-soil DC potentials, steps 1-4, except for step 3 where the scale setting of the voltmeter must be changed to AC voltage.
- 2. Notify appropriate personnel immediately if any reading is above 15 volts AC.

Measure Casing-to-Soil Potentials, DC

Repeat steps 1-4 from "Measure Pipeline-to-Soil Potentials, DC" for all casings, except connect voltmeter's positive lead to the test station lead connected to the casings. Keep the voltmeter negative (common) connected to the half-cell. If test station lead to the casing does not exist or produces a questionable reading, crosscheck by connecting positive lead of voltmeter directly to a clean metallic spot on the casing vent pipe, and retake reading.

- 1. NOTE: missing or inactive test station lead wire in "Comment" section of Form WTG 1203, or cathodic data gathering software.

Measure Amperage at Test Stations Where Anode Lead-Wire(s) Come Above-ground:

- 1. Use voltmeter on DC millivolt scale to read voltage drop across shunt, if installed. Be sure to record direction of current flow, positive or negative, using the following convention for use of the voltmeter: attach pipeline side of the shunt to the positive lead of the voltmeter, and the anode side to the negative, or "common" lead.
- 2. Record the DC millivolt reading, and whether the voltage is positive or negative.
- 3. Forward all results to appropriate personnel for interpretation.

Close Interval Survey (as needed)

- 1. Determine type of close interval survey to be performed.
 - a) Distance to cover



- b) Spacing between readings
- 2. Bring proper equipment:
 - a) Hi-impedance voltmeter
 - b) Copper-copper sulfate reference electrode (half-cell)
 - c) Test leads
 - d) Spool wire
 - e) Data logging equipment if available
- 3. Take readings, and record properly in field notes.
- 4. Forward all results to appropriate personnel for interpretation.



Description	This procedure is designed to check for proper operation of cathodic protection rectifiers.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	Six times per calendar year at intervals not to exceed 2 ½ months. Starting in January 2022 Rectifier inspections can be completed remotely however at least once per calendar year not to exceed fifteen months the rectifier must be physically inspected in person.	
Reference	49 CFR 192.465	<i>External Corrosion Control: Monitoring</i>
Forms / Record Retention	F-192.709 WTG 1200 WTG 1201	<i>Repair Work Order / Life of Pipeline System</i> <i>Rectifier Inspection Form / Life of Pipeline System</i> <i>Interference Bond Data Sheet / Life of Pipeline System</i>
Related Specifications	None	
OQ Covered Task	0101 <i>Inspect Rectifier and Obtain Readings</i> 0111 <i>Maintain Rectifier</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

NOTE: Refer to procedure P-192.483 for needed remedial actions. Remedial action must be taken promptly.

Inspect Rectifier

Remote Inspections: Amperage and voltage levels must be reviewed and recorded to ensure proper cathodic protection is being maintained during remote inspection.

Physical Inspections:

Note: No Rectifier should be touched until the case is checked for AC voltage with an approved voltage detection instrument. Rectifier chassis ground operability should be verified.

1. Read volts across rectifier terminals with appropriate voltage meter. Record on Form WTG 1200 or a comparable digital spreadsheet that gathers all pertinent information, or cathodic data gathering software.
2. Read amps utilizing an appropriate multi-meter or amp meter in conjunction with the main rectifier shunt. If amps on panel meter do not agree with amps determined by shunt, adjust the panel meter. If the unit is equipped with a multi circuit negative bond box then all shunts should be read and recorded.
3. Record tap positions, coarse and fine. Also check oil level if applicable.
4. Write a work order (Form F-192.709), if any step above shows rectifier is not working properly.

Adjust Calibrate Rectifier

1. Turn rectifier "off" with external switch or the provided switch/breaker.
2. Increase the fine tap setting in progressive steps. Turn rectifier back "on" after each step, and take pipe-to-soil potential off nearest test station reading again. Continue fine adjustment step-wise until desired pipe-to-soil has been achieved.
3. If the fine tap setting reaches its highest setting and desired pipe-to-soil potential has not yet been achieved, turn rectifier "off" again. Set fine tap to the lowest setting and increase the coarse tap setting by 1. Turn rectifier back "on" and recheck pipe-to-soil pipeline voltage. Repeat step-wise fine tap adjustments per step 2 until desired pipeline voltage is obtained.
4. Record final new tap settings, and voltage and amperage outputs. Read amperage across permanent shunt utilizing a high impedance multimeter. The multimeter setting shall be in the millivolt position. Take reading on millivolt meter, keeping in mind some shunts have correction factors which should be taken into consideration to determine true amperage reading.



Troubleshoot/Repair Rectifier and Bond Connections

1. Complete the following on primary AC breaker:
 - a) With power on, ensure the voltage is being supplied to the rectifier by confirming AC voltage on the line side of the rectifier's circuit breaker.
 - b) With the rectifier's circuit breaker closed, ensure the voltage is being supplied to the rectifier by confirming AC voltage on the load side of the rectifier's circuit breaker.

NOTE: AC voltage should be the same on the supplied and load sides of the circuit breaker.

2. Complete the following on primary AC fuses:
 - a) Remove fuse or fuses.
 - b) Check fuse or fuses for continuity with ohmmeter.
3. Complete the following on Transformer:
 - a) With the unit on, check the transformer secondary by reading AC voltage between the center studs of the tap setting terminals.
 - b) Voltage may be checked between any of the secondary taps.
 - c) The entire secondary winding can be measured between the highest coarse tap and the highest fine tap.
 - d) If the circuit breaker trips, indicating a short circuit, the transformer may be isolated from the DC circuit by removing either coarse or fine adjust link.
 - e) If the circuit breaker continues to trip, look for visible shorts between the transformer leads.
 - f) If the circuit breaker does not trip, the short is not in the transformer, but in the DC circuit.
4. Complete the following on secondary AC fuses:
 - a) Remove secondary AC fuses located in the circuit between the center studs of the tap setting terminals and the bridge connections on the stack.
 - b) Check fuse and fuses for continuity with ohmmeter.

5. Complete the following on Stack:

CAUTION – To check diodes in a stack, turn off at the unit breaker.

- a) Remove either the fine or coarse tap link bar.
- b) Remove either the positive or negative DC output lead.
- c) Connect one ohmmeter lead to either the coarse or fine tap center stud and the other lead to the positive terminal. Reverse the leads and check again.
- d) Move the lead from the positive terminal to the negative terminal. Reverse the leads and check again.
- e) Remove the other lead from whichever tap center stud it is connected to. Place it on the other tap center stud and repeat the checks at the negative and positive output terminals.



- f) Each diode should have a low resistance value in the forward direction and a very high or infinite resistance measured in the reverse direction. If a diode has a low or high resistance in both directions, replace and retest the stack.
- 6. Complete the following on DC fuses:
 - a) Remove fuse or fuses.
 - b) Replace defective fuse or fuses with proper size fuse.
- 7. Does rectifier need adjusting?
 - a) No – Continue with step 9.
 - b) Yes – Seek assistance from appropriate personnel for additional investigation and corrective actions before making any adjustments.
- 8. Examine rectifier for any abnormal defects.
- 9. Record all required information.

Repair or Replace Defective Rectifier Components

- 1. Complete the following on primary AC breaker:
 - a) Disconnect wires from supply to breaker.
 - b) Disconnect wires from breaker to rectifier.
 - c) Replace defective breaker with new breaker.
 - d) Connect wires from breaker to rectifier.
 - e) Connect wires from AC supply to breaker.
- 2. Complete the following on primary AC fuses:
 - a) Remove fuse or fuses.
 - b) Replace defective fuse or fuses with proper size fuse.
- 3. Complete the following on transformer:
 - a) Disconnect wires from rectifier AC breaker to transformer.
 - b) Disconnect wires from transformer to coarse and fine tap panels.
 - c) Replace defective transformer with new transformer.
 - d) Connect wires from transformer to coarse and fine tap panel.
 - e) Connect wires from transformer to AC rectifier breaker.
- 4. Complete the following on stack:
 - a) Disconnect wires from fine and coarse tap panel to stack.
 - b) Disconnect wires from stack to positive and negative DC output terminals.
 - c) (If stack is selenium) Remove stack and replace with new stack.



- d) (if stack is silicon) Remove defective diodes and replace with new diodes.
- e) Connect wires from stack to positive and negative DC output terminals.
- f) Connect wires from fine and coarse tap panel to stack.
- 5. Complete the following on DC fuses:
 - a) Remove fuse or fuses.
 - b) Replace defective fuse or fuses with proper size fuse.
- 6. Examine rectifier for any abnormal defects.
- 7. Does rectifier need adjusting?
 - a) NO – Continue with step 8.
 - b) YES – Seek assistance from appropriate personnel for additional investigation and corrective actions before making any adjustments.
- 8. Record all required information.
- 9. Complete the following on Bonds:
 - a) Measure the pipe to soil potential at the major bond for both the company pipeline and the foreign structure.
 - b) Measure and record the current flow and direction of the flow through the bond. If no current flow exists, check all circuit connections including but not limited to cable connections (including connections to the structure) and shunt connections.
 - c) All critical bonds shall be read and recorded every 2 months not to exceed 2 1/2 months or 6 times per year on WTG FORM 1201, or a cathodic data gathering software. All noncritical bonds shall be read and recorded annually. Not to exceed 15 months.



Description	To check metallic bonds between pipeline and foreign structures used to eliminate detrimental effect of interferences. This procedure also handles anodes placed at positions of known low pipeline voltage in lieu of a metallic bond when foreign interference has been determined to exist.	
Regulatory Applicability	Cathodically protected pipe with metallic bonds to foreign pipelines or structures or to anodes placed in lieu of metallic bonds. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Reverse current switches, diodes and interference bonds that can jeopardize structure protection on gas pipelines must be inspected six (6) times per year at an interval not to exceed 2½ months. All other bonds must be inspected once each calendar year at intervals not to exceed 15 months.	
Reference	49 CFR 192.463	<i>External Corrosion Control: Cathodic Protection</i>
	49 CFR 192.465	<i>External Corrosion Control: Monitoring</i>
	LA Title 43 Part XIII 2115	<i>External Corrosion Control: Cathodic Protection</i>
	LA Title 43 Part XIII 2117	<i>External Corrosion Control: Monitoring</i>
Forms / Record Retention	F-WTG 1203	<i>Cathodic Protection (non-critical bonds) / Life of Pipeline System</i>
	F-WTG 1200	<i>Rectifier Inspection Form / Life of Pipeline System</i>
	F-WTG 1201	<i>Interference Bond Data Sheet / Life of Pipeline System</i>
Related Specifications	None	



**OQ Covered
Task**

0061 *Inspect or Test Cathodic Protection Bonds*

0101 *Inspect Rectifier and Obtain Readings*

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

NOTE: Refer to procedure P-192.483 for needed remedial actions. Remedial action must be taken promptly. If rectifier located in Louisiana, the remedial action must take place within 90 days.

Test Reverse Current Switches and Diodes

1. Record current flow using either a calibrated shunt or a clamp-on ammeter.
2. In remote locations, high internal resistance ammeters may be used in series with the circuit provided the added resistance does not affect the required current and it does not produce an error in the reading. In this case, the pipe-to-soil potentials are not required unless the current changes by 20% or more from any reading since the last CPSS.

Test Bonds

1. Use hi-impedance voltmeter, test leads, and copper-copper sulfate half-cell.
2. Measure the pipe-to-soil potential at each bond of the company pipeline to a foreign structure. The bond may be a metallic wire connected to the foreign structure, or it may be sacrificial anodes that have been specifically placed to mitigate adverse effects of foreign interference current leaving the company pipeline.

- a) When taking a pipe-to-soil potential reading, place reference half-cell on ground directly over the location where bond wire connects to the company pipeline.

NOTE: This may not be the same location as where the test station containing the shunt and the lead wire from the foreign structure is located

- b) Connect the reference cell to the voltmeter negative (common) terminal, and the lead wire from the company pipeline (at test station) to the voltmeter positive terminal. If necessary, use a close-interval wire reel to connect the voltmeter positive to the test station while keeping the reference cell properly positioned.
 - c) Record results on Form F-WTG-1201.
 - d) If pipe-to-soil voltage is more positive than -0.85 volts DC, seek assistance immediately from appropriate personnel.
3. Measure and record the magnitude of current flow (millivolts across shunt,) and the direction of current flow.



4. Determine direction of current flow using the following convention:
 - a) Attach the positive lead of the voltmeter to the side of the shunt connected to the company pipeline.
 - b) Attach the negative (common) lead to the side of the shunt going to the foreign structure. Current flow must be "positive" if the company line was the "affected" pipeline. Record results on Form WTG 1201
 - c) If no current flow exists check all circuit connections: cable connections, shunt connections, and any resistors and/or diode connections.
 - d) If after field-inspection no current flow can be detected, or if current flow is negative, notify management and seek assistance from appropriate personnel for additional investigation
 - e) If a diode is used, temporarily jumper it out and recheck shunt voltage and direction of current flow. Record both in the appropriate section of Form WTG 1200. Remove the temporary jumper and log the removal on same form.



Description	To document corrective actions taken when Cathodic deficiencies are discovered	
Regulatory Applicability	All Cathodically Protected Pipe <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> All Gathering Pipelines <input checked="" type="checkbox"/> All Distribution Pipelines	
Frequency	Within a timely manner after the discovery of a Cathodic deficiency	
Reference	49 CFR 192.465	<i>External Corrosion Control: Monitoring</i>
Forms / Record Retention	F-192.465(d)	CP Remediation Log / Life of Pipeline System
Related Specifications	None	
OQ Covered Task	0061	<i>Inspect or Test Cathodic Protection Bonds</i>
	0101	<i>Inspect Rectifier and Obtain Readings</i>



Procedure Steps

1. Upon the discovery of a cathodic deficiency that cannot be corrected onsite, immediately contact the District / Division Manager.
2. Remedial action will be developed and (pending approval) started. This process will be documented using F-192.465(d).
3. WTG must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of CFR 192.465. For WTG transmission pipelines, we must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.
4. In the event that traditional remediation techniques do not correct deficiencies, the corrosion SME will determine the extent of the area with inadequate cathodic protection for gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in CFR 192 appendix D and implement the following.
 - a. WTG must investigate and mitigate any non-systemic(location-specific) inadequate cathodic protection causes on all transmission pipelines.
 - b. If the deficiencies affect entire geographical area/segment the issue is deemed to be systemic. To address systemic causes, WTG must
 - i. Conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. WTG must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons.
 - ii. Remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of CFR 192.465.
 - iii. Confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.



Description	This procedure describes the requirements for re-evaluating unprotected pipe after conducting the initial evaluation required by 49 CFR 192.455 (b), (c) and 192.457(b) and determining if they need to be cathodically protected in accordance with 49 CFR 192.452, 455 or 457.	
Regulatory Applicability	All unprotected DOT gas pipelines <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input type="checkbox"/>	
Frequency	Once every 3 years, not to exceed 39 months	
Reference	49 CFR 192.465 <i>External Corrosion Control: Monitoring</i> 16 TAC Rule 8.203 <i>Supplemental Regulations</i> LA Title 43 Part XIII 2117 <i>External Corrosion Control: Monitoring</i>	
Forms / Record Retention	F-192.465(e) System	<i>Re-evaluation of Unprotected Pipelines / Life of Pipeline</i>
Related Specifications	None	
OQ Covered Task	0001 <i>Measure Structure-to-Electrolyte Potential Surveys</i> 0011 <i>Conduct Close Interval Survey</i> 0021 <i>Measure Soil Resistivity</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

NOTE: If an electrical survey is impractical, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. ("Active Corrosion is defined as continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.")

1. Visually inspect below-ground unprotected pipe that is naturally accessible, if applicable, for active corrosion.
2. Determine areas of active corrosion by electrical survey or where affected by other means that include review and analysis of leak repair and inspection record, corrosion monitoring records, exposed pipe inspection records, and other effective means, documented by data substantiating results and determinations.

NOTE: If a leakage survey issued to determine the area of active corrosion, the survey frequency must be increased to monitor the corrosion rate and control the condition. The detection equipment must have the sensitivity adequate to detect gas concentration below the lower explosive limit and be suitable for such use.

3. Cathodically protect areas that contain "active corrosion". Follow procedure P-192.455.
4. Evaluate the MAOP of the pipeline and revise as necessary. Follow procedure P-192.619.
Repair as necessary. Follow procedure P-192.711.



Description	This procedure outlines the requirements for electrical isolation of buried or submerged pipeline facilities.			
Regulatory Applicability	All regulated buried or submerged gas pipelines that are not electrically interconnected and cathodically protected as a single unit with other underground structures. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines			
Frequency	After pipe repairs, at installation, when a new crossing is conducted, or anytime there is a suspect that there may be interference with the cathodic protection system. Testing must also be performed to ensure that the isolation is adequate.			
Reference	49 CFR 192.467 <i>External Corrosion Control: Electrical Isolation</i> LA Title 43 Part XIII 2119 <i>External Corrosion Control: Electrical Isolation</i>			
Forms / Record Retention	None			
Related Specifications	None			
OQ Covered Task	0071	Inspect or Test Cathodic Protection Electrical isolation Devices		
	0081	Install Cathodic Protection Electrical Isolation Devices		
	0091	<i>Troubleshoot System</i>	<i>In-service</i>	<i>Cathodic Protection</i>
(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)				



Procedure Steps

Standard Electrical Isolation Method

1. Flange Insulation

Standard raised-face flanges may be made an insulating device by installing an insulating kit in the flange. An insulating kit consists of an electrically non-conductive gasket, non-conductive sleeves to encase the studs, and non-conductive washers for both nuts of a stud. Steel washers should also be placed immediately under nuts to protect the insulating washer from being crushed during torquing. Where applicable, equipment grounding shall be verified or implemented.

When welding the insulating flange unit or the weld type insulated coupling into the line, care shall be exercised to be sure that the insulation is not damaged by the current "arc" that could occur from welding. This can be achieved by moving the ground cable to the same side of the flange set as the electrode cable thus eliminating current "arc" across the insulating flange during welding.

2. Monoblock Insulating Joints

Monoblock insulating joints are factory-assembled insulating assemblies that are welded into a pipeline; they have no serviceable parts.

3. Insulated Unions

Insulating unions are usually used for small-diameter (3 inches or less) piping attachments that require electrical insulation.

4. Casing Centralizers and End Seals

Non-conductive centralizing devices are attached to pipelines where the carrier pipe passes through a cased crossing. These centralizers prevent electrical contact between the casing and the carrier pipe. Casing end seals prevent water or soil from entering the annular space between the carrier pipe and casing and causing an "electrolytic" short between the casing and pipe.

5. Other Devices

Frequently, high-pressure laminated (e.g., micarta) dielectric blocks or neoprene rubber pads are used to electrically isolate a pipeline from supports or other structural appurtenances that are not a part of the cathodically protected pipeline.

Cased Crossings

Whenever possible, casing installations should be avoided. In some cases, however, railroad or public highway regulations required the installation of a casing for railway right-of-way or road crossings. When casings are required, the carrier pipe must be electrically isolated from the casing.



Electrical Isolation from a Foreign Pipeline Crossing

The pipeline can be tested for corrosion by conducting several pipe-to-soil potential readings either side of the crossing point. Adequate potential levels indicate isolation from the foreign pipeline. Adequate potential levels indicate isolation from the foreign pipeline.

If the potential levels are low in the area of foreign pipeline crossings, inadequate levels of isolation are indicated. This can be corrected by:

1. Installing anodes on our pipeline in this area until potential levels are adequate
2. Excavating the area and coating our pipeline with a suitable coating that achieves isolation
3. Excavating the area of crossing and physically separate the two pipelines until isolation is achieved.
4. Bonding the two pipelines together with resistance bonds to achieve protection from interference.

Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or other areas containing fault currents, protection must be provided by:

1. Kirk Cells
2. Current diodes
3. Fault interrupters



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Description	To describe the installation procedure for corrosion control test stations. This will ensure that pipelines under cathodic protection have sufficient test stations or other contact points for electrical measurement to determine adequacy of protection.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed. May be required for new construction and/or for existing pipelines that require additional or replacement test stations.	
Reference	49 CFR 192.469	<i>External Corrosion Control: Test Stations</i>
	49 CFR 192.471	<i>External Corrosion Control: Test Leads</i>
	LA Title 43 Part XIII 2121	<i>External Corrosion Control: Test Stations</i>
	LA Title 43 Part XIII 2123	<i>External Corrosion Control: Test Leads</i>
Forms / Record Retention	Update maps to show location.	
Related Specifications	None	
OQ Covered Task	0041	Installation and Maintenance of Mechanical Electrical Connections
	0051	<i>Installation of Exothermic Electrical Connections</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

1. Determine location of needed test station. Test leads should be less than 1 mile apart.
 - a) Each pipeline must have test stations that are:
 - i) Installed at each cased segment of pipeline, public roads, and railroad crossings. Note: Two test leads should be installed on the casing and two leads should be installed on the carrier pipe.
 - ii) Installed at each foreign metallic pipeline crossing.
2. Determine how test lead will be attached (Cadweld, thermite welding, magnetic block, brazing, non-acid solder) and follow the appropriate portion of this procedure.
3. Gather all needed permits – hot work, confined space entry.
4. Excavate area around pipe where leads will be attached. Take care not to damage the pipe or any other facilities in the area of excavation. Follow procedure P-192.319.
5. Remove existing coating to attach leads. Clean pipeline carefully in area where attachment will be made.
6. Determine wall thickness (connection cannot be made in an area of thinned pipe).
7. Wrap test leads around pipe and tie in a knot. Ensure that the connection will be mechanically secure and electrically conductive.
8. Make permanent connection using the appropriate portion of this procedure.
9. Coat test lead wire and pipe connection with an electrical insulating material compatible with the pipe coating and the wire insulation.
10. Prior to backfilling, measure the pipe-to-soil potential to ensure electro-conductivity between the wire and pipe.
11. Backfill without disturbing the test station or wires. Follow procedure P-192.319.
12. Install post or pole that will be the station marker directly above the pipeline. Do not connect the post or pole directly to the pipeline.
13. If more than one pipeline is monitored at this test station, attach permanent labels designating each pipeline to the appropriate station terminals and wires.
14. Add test station number and location to the most recent annual survey and map.
15. Distribute revised maps as required.



Inspect and Verify Test Lead Continuity

1. Have a qualified individual measure structure-to-soil potential.
2. Verify that the reading is within the desired range.
3. Confirm that test leads are installed and terminated properly and that test leads are not damaged.
4. If test lead continuity is not found, identify damage if possible and recommend mitigation actions based on readings and visible condition of the test lead.
5. Document findings in proper format.

Repair Test Lead

1. Identify the test lead damage.
2. Where necessary, make proper notifications to operations prior to working around structure.
3. Repair test lead damage.
4. Verify that test leads function properly and are no longer damaged.
5. Where necessary, make proper notifications to operations that work has been completed.
6. Document actions and readings.

Cadweld Procedure Steps

Cadweld General and Safety Information

1. Only CADWELD manufactured equipment and materials should be used to make CADWELD connections.
 - a) Do not connect items except as detailed on mold tag and in the instructions.
 - b) Do not use worn or broken equipment that could cause leakage.
 - c) Do not alter equipment or material without factory authorization.
 - d) Do not substitute for specified CADWELD manufactured equipment and materials.
 - e) Failure to comply with the above may result in hazards to the individual, improper connections, or damage to the items being connected.
2. Starting and welding materials are exothermic mixtures and react to produce molten materials with temperatures in excess of 2200° C (4000° F) and a localized release of smoke. These materials are not explosive. Ignition temperatures are in excess of 460° C (860° F) for starting material, and 900° C (1650° F) for welding material.



3. Make connections in accordance with the prescribed welding procedures and in consideration of surrounding conditions and personnel. Refer to ANSI Z-49.1 Safety in Welding and Cutting and your local safety procedures.
 - a) Personnel should be properly trained to use this product.
 - b) Avoid direct eye contact with flash of light from ignition of starting material.
 - c) Avoid breathing concentrations of smoke as it may be hazardous to health.
 - d) Avoid contact with hot materials.
 - e) Advise nearby personnel of welding operation in the area.
 - f) Remove or protect fire hazard in the immediate area.
 - g) Do not smoke when handling starting material.
4. Adhering to the recommended welding procedures will minimize risk of burns and fire caused by hot molten material spillage.
 - a) Make sure there is proper mold fit and assembly of equipment.
 - b) Avoid moisture and decomposable contaminants in mold and materials being welded. Contact of hot molten material with moisture or contaminants may result in spilling of hot material.
 - c) Material thickness must be sufficient for the size and type connection being made to prevent melt-through and leakage of hot molten metal.
5. Unusual application or condition may exist that require special considerations.
 - a) Provide adequate ventilation where natural air flow is not sufficient to prevent personnel breathing concentrations of smoke.
 - b) In case of fire, water or CO₂ will aid control of burning containers. Large quantities of water will aid in controlling a fire should the exothermic materials become involved. Water should be applied from a distance.

Preparation

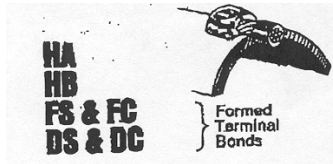
1. Cable, Ground Rods, and Lugs
 - a) Use cable cutters to minimize deforming cable. Burnt or out-of-round cable ends may mold open, causing leaks.
 - b) Conductor ends and adjacent length must be clean and dry to insure a good weld.
 - c) When using adaptor sleeves, let conductor protrude 1/8" beyond end of sleeve.
2. Steel or Cast Iron Surfaces
 - a) Surface must be clean to insure a good weld. Remove any surface protection. Use CADWELD CAT-321 rasp to avoid contaminating welding areas.



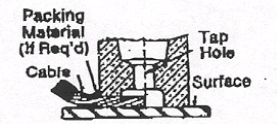
- b) Abrade "standard galvanized" surface with emery cloth to remove surface oxides in weld area. Clean "double or triple" galvanized surfaces with rasp to remove galvanizing in weld area.

Welding Procedure

1. Check the following:
 - a) Mold is correct for the conductor sizes and application. DO NOT MODIFY MOLDS.
 - b) Weld metal indicated on mold tag and steel disks are available. USE ONLY CADWELD WELD METAL.
 - c) Frame is attached to mold and adjusted properly.
 - d) Flint igniter is in working order.
2. Make sure mold is dry, clean and in good condition. Mold can be dried by heating to about 120° C (250° F).
3. Position mold on conductors following appropriate positioning instructions making a reference mark on conductors at entry point on mold aids in conductor positioning. Check before ignition and for inspection of completed connection.
4. Close mold and lock tightly with handle clamp if split type mold.
5. Use ERICO packing material to pack all openings around conductors at entry point into mold to prevent leaks of molten material, especially where noted on positioning instructions.
6. Insert steel disk, ditched (concave) side up, in crucible to cover tap hole.
7. Pour weld metal into crucible being careful not to upper the steel disk.
8. Tap weld metal container to loosen starting material. Place approximately 1/4 to 1/3 of the starting material on the top lip of the mold at cover opening. Distribute the remaining starting material over the welding material.
9. Close cover.
10. Check reference marks on conductor to verify correct positioning.
11. Stand to side of cover opening and unwind. Aiming flint igniter from the side, ignite starting material on mold lip. Withdraw igniter quickly to prevent fouling.
12. Allow approximately 30 seconds for completion of reaction and solidification of molten material.
13. Open and remove mold. Use care to prevent chipping mold.
14. Clear mold of residue using natural bristle, a soft-cloth, or newspaper before making the next weld. Dispose of residue and weld material package properly. USE CARE TO AVOID BURNS FROM HOT MOLD, CONNECTION, CONDUCTORS OR RESIDUE.

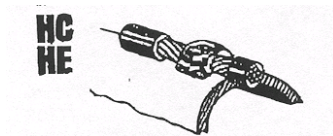


Place mold against surface with end of cable under center of tap hole #1 AWG and larger cables require the use of packing material to seal the mold cable opening. Use the handle or Cat. No CAT-340 Chain Clamp to secure mold to surface.

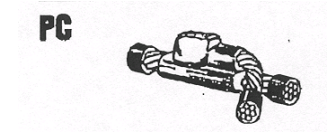
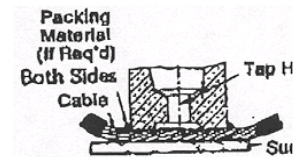


Field Made Formed Terminal Bonds

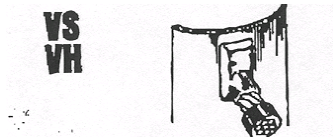
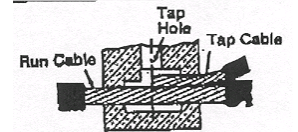
1. Insert cable thru sleeve with end protruding 1/8". Place in hammer die, close cover and form with cable protruding as noted.



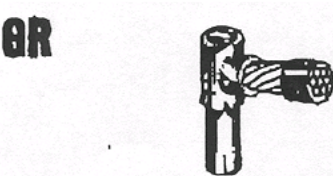
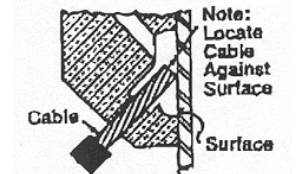
2. Place mold over cable and against surface. Follow "HA" instructions.



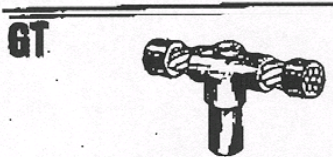
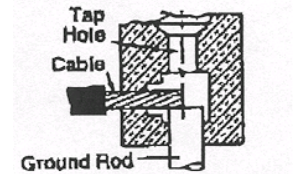
3. Place mold on run cable with end of tap cable under center of tap hole.



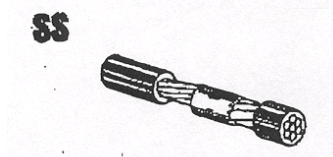
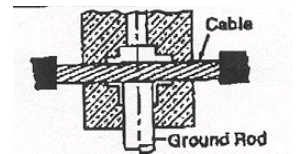
4. Place mold against surface with cable positioned as shown. Secure mold to surface with Cat. No. CAT-339 Chain or with "C" clamp.



5. Place mold on ground rod with end of cable positioned on top of rod and under center of tap hole. Cable must sit on top of rod as shown.

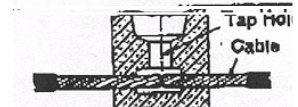


6. Place mold on ground rod with cable positioned across top of rod as shown.



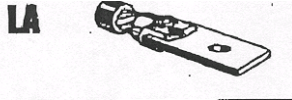
#4 AWG and LARGER

Place mold on cables with ends butting under center of tap hole.

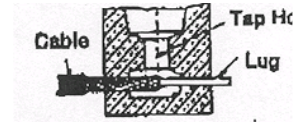
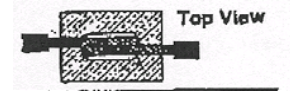


#6 AWG and SMALLER

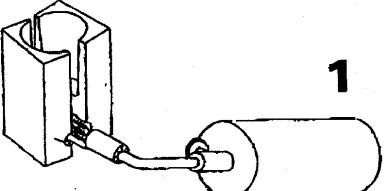
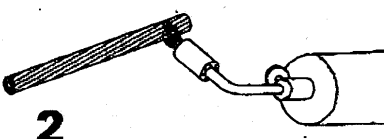
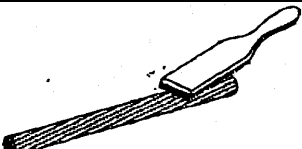
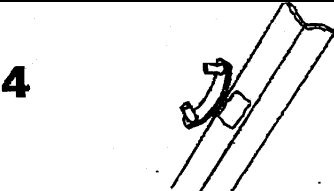
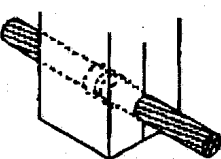
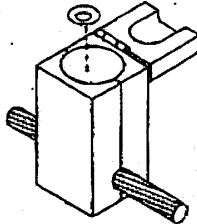
Place mold on overlapped cables and push each cable in until they bottom in weld cavity

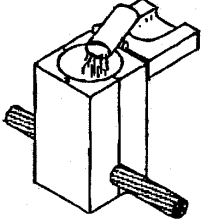
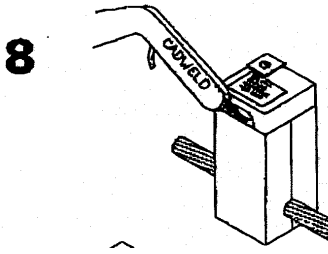
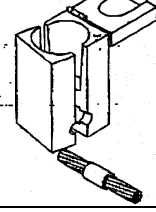
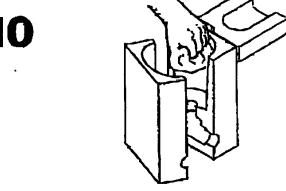
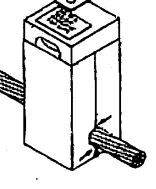


7. Place mold on cable and lug with ends butting under center of tap holes.



Cadweld Condensed Instructions

 <p>1</p>	<p>Before first connection of the day, dry the mold by heating with a torch.</p>
 <p>2</p>	<p>Dry conductors to be welded with a torch.</p>
 <p>3</p>	<p>Clean dried cable ends with a brush to remove dirt and oxides.</p>
 <p>4</p>	<p>When welding to a steel surface, use a rasp or Erico approved grinding wheel SBS2333 to remove paint, rust and mill scale from area to be welded. (Bright metal showing.)</p>
 <p>5</p>	<p>Position mold over conduction with conductor ends under center of tap hole. Gap distance, if required, is noted on mold tag.</p> <p>Lock mold handles.</p>
 <p>6</p>	<p>Insert round metal disk (packaged with weld mold) in bottom of crucible. Make sure it covers tap hole.</p>

	<p>7</p> <p>Dump in weld material.</p> <p>Sprinkle starting material on mold lip and over weld material.</p>
	<p>8</p> <p>Close cover.</p> <p>Ignite with spark from flint igniter.</p> <p>Note: Do not use a torch or matches</p>
	<p>9</p> <p>Wait 10-15 seconds.</p> <p>Open mold and remove from finished connection.</p>
	<p>10</p> <p>Remove slag and dust with clean rag or mold cleaning tool.</p> <p>Do not use a wire brush.</p> <p>*(An old natural bristle paint brush is ideal.)</p>
	<p>11</p> <p>Discard mold when excessive leakage occurs around mold openings or if mold disk seat is worn or chipped. Molds are not permanent equipment. They do wear out.</p>



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Description	This procedure gives steps in minimize stray currents and to prevent the adverse effects on gas pipelines.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.473	<i>External Corrosion Control: Interference Currents</i>
Forms / Record Retention	F-192.455 WTG 1200 WTG 1201	Installation of Cathodic Protection Systems / Life of Pipeline Rectifier Inspection Form / Life of Pipeline System Interference Bond Data Sheet / Life of Pipeline System
Related Specifications	Section 9 of NACE RP0169-02 <i>Control of External Corrosion on Underground or Submerged Metallic Piping Systems</i>	
OQ Covered Task	None (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

1. For WTG's pipelines systems that are subject to stray currents will have in effect a continuing program to minimize the detrimental effects of such current.
2. The company shall actively participate in corrosion coordinating committees or groups when available. These committees distribute information concerning the operation of cathodic protection systems for the purpose of providing opportunity for utilities to conduct cooperative interference testing to detect stray current interference conditions. When corrosion coordinating committees do not exist in the area, the company will make attempts to identify area utilities and structures that may be affected by company-operated cathodic protection systems and notify these utilities. The cathodic protection system information is distributed for new installations prior to activation and for existing systems if the output will increase above previously approved levels. When detected, the stray current interference conditions shall be resolved by mutual agreement between affected parties. Resolution of the stray current interference conditions may include but are not limited to installation of interference bonds, installation of galvanic anodes, and repair of coating deficiencies.
3. Unexpected and/or unusual variations in cathodic protection measurements encountered during normal testing will be evaluated to determine whether these test results may be caused by stray current interference. The company will work through corrosion coordinating committees or by direct contact with area utilities or other pipeline operators to resolve whether interference may be the cause of the unexpected and/or unusual test results and to resolve the stray current interference condition, if it exists.
4. Designs and installation for new cathodic protection systems will include evaluation of possible stray current interference effects on adjacent metallic structures. The design of the cathodic protection system will be modified to eliminate or minimize the stray current interference affects. If the cathodic protection system design can not be modified to eliminate or minimize the stray current interference effects, the owner of the adjacent metallic structure shall be contacted to determine if there will be objections to the proposed installation and what mitigative measures could be installed to resolve the objections. Use the process defined in Step 2 to resolve the issue of stray current interference on adjacent metallic structures.
5. Section 9 of NACE RP0169-02, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" may be used for guidance with stray current mitigation.

General Discussion

To establish foreign interference, two fundamental conditions must exist. First, there must be at least two conductive breaks or "holidays" in the coating of the affected line. One will let foreign current get onto the line, and the other(s) will allow the foreign current to leave.

Secondly, the foreign line must have enough voltage difference between parts of its own system so that it has pipe-to-soil voltages (in different areas) that are both higher and lower than the pipe-to-soil potentials of the pipeline being interfered with. Some part of the foreign pipeline (or structure) must be more positive in DC potential than the pipeline being interfered with, in order to get current to flow onto the affected pipeline. Additionally, voltage at another part of the foreign



pipeline must be more negative than voltage on the affected line at the location where the foreign interference current leaves. This happens by the voltage of the interfered-with pipeline becoming less negative and rising at the point of current discharge, rather than any perceptible negative shift happening to the voltage on the foreign line.

The anode-side of a rectifier is the most positive voltage source to be considered in looking for a high (positive) DC potential on a foreign structure. Foreign current coming onto the affected pipeline will cause the affected pipeline's pipe-to-soil voltage to be more negative than the normal voltage in the immediate surrounding area. Foreign current leaving the affected pipeline (which is the location of possible severe localized corrosion) will shift the affected line's pipe-to-soil voltage to be less negative than the line's "normal" voltage in areas immediately adjacent to the current discharge area.

The shifts in the affected pipeline's pipe-to-soil potentials are visible on a close-interval survey.

Also, note that the voltage shifts caused by foreign interference can be sharp, and confined to small areas. It is likely that foreign interference will not be detected by review of test-station data alone.

The locations of current in-flow and out-flow on the affected line may be very close to each other, or they can be widely separated, perhaps several miles apart.

It is also possible, especially near the area of a foreign pipeline's rectifier, for foreign current to get onto a neighboring pipeline by flowing in reverse through the neighboring (affected) pipeline's sacrificial anodes. The presence of an anode in this case acts like a break in the coating, and will cause a corresponding current discharge at another location. This discharge will cause corrosion to the affected line, and possibly pipeline failure, if it is either not stopped, or if it does not occur through either a metallic bond with the foreign pipeline or through anodes installed at the location of the current discharge.

Checking for Interference Procedure Steps

1. Review close interval survey or structure-to-soil potentials for possible interference. Look for unexplained rises or falls in voltage not explained by positioning/condition of anodes, or changes in soil condition.
2. Determine possible sources of the cathodic interference. Note: This can sometimes be difficult to accomplish. The following steps are often useful:
 - a) Determine whether any impressed current ground-beds for foreign structures are near the affected pipeline.
 - b) Consider routes of foreign pipelines and locations of any associated rectifiers in deciding which foreign pipelines to investigate. Foreign pipelines that run parallel to the affected pipeline are more likely to contribute to interference than pipelines that approach and cross the affected pipeline's route only a single time. Also consider the proximity of any branches of a foreign pipeline to the affected pipeline.
 - c) Either measure directly the structure-to-structure potential difference between the affected pipeline and foreign structure(s) suspected of causing interference, or measure the



structure-to-soil potentials of both pipelines separately, but without moving the reference half cell between the pairs of readings.

- d) Discuss with personnel representing a suspected foreign structure the usefulness of impressing clearly distinguishable on/off cycles of applied known potential on the foreign structure(s), and look for a corresponding response pattern of changing pipe-to-soil potentials on the affected (interfered with) pipeline.
3. Recommend the most effective method of interference mitigation between the structures. If it is possible to do, repair of the coating break(s) on the affected pipeline that allows foreign current to enter that pipeline should be considered.
4. Document readings and recommended mitigation in appropriate format.
5. If a foreign interference is determined to exist, and the pipeline's pipe-to-soil voltage is more positive than -0.85 volts, time will be of the essence. It will be imperative that corrective action be taken quickly in order to avoid a possible leak. Management must be immediately notified that such a condition exists.
6. If a bond is used to mitigate interference effects, use Form F-WTG 1201 to record initial information about connection. Use Form F-WTG 1200 to record performance information at least 6 times annually, at intervals not to exceed $2\frac{1}{2}$ months.
7. High Voltage Alternating Current (HVAC) power lines, new or enlarged power substations, wind energy and solar installations can cause both AC and DC interference. They can also include additional generation, voltage, uprating and or additional power lines. WTG performs pipeline patrols and pipe-to-soil surveys which ensure the total pipeline is inspected at required intervals. Upon discovery of interference, WTG will perform remedial actions from detrimental interfering currents no later than 15 months after discovery with allowance for permitting. This is only applicable to Transmission pipelines.



Description	To ensure prior to transporting corrosive gas in the pipeline, the corrosive effect of the gas on the pipeline is investigated and steps are taken to minimize internal corrosion.
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Note: In the state of Texas: Corrosive gas" means a gas which, by chemical reaction with the pipe to which it is exposed, usually metal, produces a deterioration of the material."

Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input type="checkbox"/>
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Frequency	As needed to determine the corrosiveness of the commodity being carried. Monitoring twice per year, but no more than 7 ½ months part.
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Reference	49 CFR 192.475 <i>Internal Corrosion Control: General</i> 49 CFR 192.476 <i>Internal corrosion control: Design and construction of transmission line</i> 16 TAC Rule 8.203 Supplemental Regulations LA Title 43 Part XIII 2127 <i>Internal Corrosion Control: General</i> LA Title 43 Part XIII 2128 <i>Internal corrosion control: Design and construction of transmission line</i>
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Forms / Record Retention	None / Life of Pipeline System
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Related Specifications	None
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**OQ Covered
Task**

1021 Apply or Repair Internal Coating Other Than by Brushing, Rolling or
 Spraying

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. If it can be determined from the MSDS or specification sheet that the gas is not corrosive, file documentation in the DOT files.
2. If necessary to determine the corrosiveness of the gas take a sample for analysis:
 - a) Locate Sample Site: Locate sample site, either for a sample container for a composite or a sample tap for a spot sample.
 - b) Check Atmospheric Conditions: Fire extinguisher operation. Utilize an appropriate air monitoring device to test for explosive or hazardous conditions.
 - c) Prepare Sample Container: Sample container must meet the requirements established by the company and/or analyzing laboratory. The sample container must also meet the Department of Transportations requirements for shipment of hazardous materials.
 - d) Collect Sample: Sample shall be collected according to industry approved practices.
3. Label the sample with the following information:
 - a) Company name
 - b) Facility/location
 - c) Product name
 - d) Date/Time
 - e) Temperature of sample
 - f) Operator name
 - g) Sample type (i.e. composite, grab or spot)
 - h) Package labeling must also meet all DOT requirements
4. Analyze the sample in company lab or ship to an appropriate lab for analysis.
5. Once report is received, have corrosion engineer determine if the sample is corrosive and if so what measures need to be taken to protect the pipe, including appropriate monitoring measures as described in procedure P-192.477.
6. File lab report and engineering analysis in DOT files.



Internal corrosion control: Design and construction of transmission line

Design and construction.

Except as provided in below, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line will have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line will:

- (1) Be configured to reduce the risk that liquids will collect in the line;
- (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
- (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

The design and construction requirements do not apply to the following:

- (1) Offshore pipeline; and
- (2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

Change to existing transmission line.

When the configuration of a transmission line changes, WTG will evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

Records.

WTG will maintain records demonstrating compliance with this section. Provided the records show why incorporating design features are impracticable or unnecessary, WTG may fulfill this requirement through written procedures supported by as-built drawings or other construction records.



Description	This procedure should be used anytime pipe is removed from the pipeline to determine the amount of internal corrosion.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.475 <i>Internal Corrosion Control: General</i> LA Title 43 Part XIII 2127 <i>Internal Corrosion Control: General</i>	
Forms / Record Retention	WTG 1100	<i>Exposed Pipeline Inspection / Life of Pipeline System</i>
Related Specifications	None	
OQ Covered Task	0161	<i>Visual Inspection for Internal Corrosion</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Orient pipe to be removed by clearly marking direction of flow in addition to top of pipe.
2. Cut and remove oriented section of pipe for analysis.
3. Label sample pipe with the following information:
 - a) Company
 - b) Facility
 - c) Operator
 - d) Date
 - e) Engineering station
 - f) Pipe grade
 - g) Wall thickness
4. Record initial inspection of the inside of pipe. This may be done in written form and may also be accompanied with a pictorial record.
5. Remove any residue with an approved solvent or mechanical means. Dispose of waste in an approved container. Care should be taken not to disturb the scale that has built up inside the pipe.
6. Record visual inspection of the inside of the pipe after cleaning. Special care should be taken in recording the patterns and location of pitting or scale buildup. This may be done in written form and may also be accompanied with a pictorial record. A sample of any foreign material recovered from the inside of the pipeline will be submitted for analysis.
7. With the use of measuring devices, measure and record the depth, diameter and duration of all pitted areas. Measure and record the remaining wall thickness around the circumference of the pipe including the pitted areas.
8. Carefully secure the pipe section to ensure it will not be damaged during transport. For future reference and analysis, transport the pipe to secure storage.
9. If internal corrosion is found, inspect the adjacent pipe to determine the extent of the internal corrosion.
10. Send all data pertaining to the removed sample and the adjacent pipe the corrosion engineer. Place a copy in the DOT files.
11. All remedial action (chemical injection, pipe replacement) will be completed prior to the next inspection. If corrosion is found in an area that has not been previously monitored, a monitoring system will be started. Refer to procedure P-192.483 for remedial measures that must be taken.



Description	This procedure gives the steps for monitoring for internal corrosion using coupons and probes.			
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines			
Frequency	Two times each calendar year at intervals not exceeding 7 ½ months.			
Reference	49 CFR 192.475	Internal Corrosion Control: General		
	49 CFR 192.477	Internal Corrosion Control: Monitoring		
	LA Title 43 Part XIII 2127	Internal Corrosion Control: General		
	LA Title 43 Part XIII 2129	Internal Corrosion Control: Monitoring		
Forms / Record Retention	F-192.477	Internal Corrosion Monitoring / Life of Pipeline System		
Related Specifications	None			
OQ Covered Task	0131	Insert and Remove Coupons/Probes for Internal Corrosion Monitoring		
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)			



Procedure Steps

Any time a segment of pipe is removed from the pipeline, the internal surface will be visually inspected for signs of pitting or damages that may be signs of internal corrosion. Also valves, meters, fitting, etc., can be examined when they are removed from the system.

NOTE: If internal corrosion has or may have reduced the wall thickness of a segment of pipe to less than 10%, pipe repair or replacement should be planned or the working pressure reduced.

Coupon Monitoring

1. Inform pipeline control center of planned activity.
2. Check wind direction and escape routes. Position yourself upwind of the liquid or gas released during the process. Identify means of egress in case of abnormal release of liquid or gas. Use personal protective equipment and clothing.
3. Remove fitting cap. Cap should be hand tight but pressure could be trapped. Remove with caution.
4. Install the valve and extractor tool on the access fitting with the service valve in the closed position and all bleeder valves closed.
5. Engage the tool in the plug assembly by revolving the hand wheel clockwise to the limit of travel while rotating the handles clockwise until resistance increases. Once the coupon is located, the hand wheel will no longer travel. Note: Tools may vary with manufacture.
6. To remove the coupon:
 - a) Remove the plug assembly from the nipple by applying slight pressure to the handle in the proper direction to extract the coupon.
 - b) Perform this function slowly, monitoring for any pressure / leaks.
 - c) Once you have achieved the required length of travel indicating that the tool has been removed clear of the service valve, close the service valve.
7. To bleed off pressure:
 - a) Install drain system to the extraction tool. Direct the end of the drain system into a containment device downwind of the assembly.
 - b) Crack the drain / bleeder valve slowly, allowing time for the pressure to be removed in a controlled fashion.
8. To Remove extractor tool:

WARNING: Do not touch the coupon with your bare hands.

- a) Break connection from the coupon holder.
- b) Check for any hazardous liquids.
- c) Remove tool with coupon.



- d) Document coupon's visual characteristics onto pull sheet.
- e) Confirm coupon is placed in its original shipping container.

9. To prepare new coupon:

WARNING: Do not touch the coupon with your bare hands.

- a) Properly record the new coupons serial number or identification and its associated shipping container.
- b) Thoroughly clean and prepare coupon holder and ancillary equipment for coupon installation.
- c) Attach new coupon-to-coupon holder.

10. To install new coupon:

- a) Install extractor tool onto the service valve.
- b) Confirm all bleeder valves are in the closed position.
- c) Equalize pressure between the process piping and the extractor tool. Inspect for leaks.
- d) Rotate tool to properly install the new coupon into the process stream.
- e) Release the tool from the coupon holder and retract the plug assembly into the extractor tool until full travel is achieved.
- f) Close service valve.

11. To bleed off pressure:

- a) Install drain system to the extraction tool. Direct the end of the drain system into a containment device downwind of the assembly.
- b) Crack the drain / bleeder valve slowly, allowing time for the pressure to be removed in a controlled fashion.
- c) Bleed off the extractor assembly of residual liquid or gas. Close bleeder valve. Monitor for pressure buildup in the tool to confirm the service valve has maintained a positive seal.

12. To remove extractor tool:

- a) Break connection from coupon holder.
- b) Check for any hazardous liquids.
- c) Dress plug threads with anti-seize and place plug back on tool adapter.

13. Inform pipeline control center planned activity is completed.

14. Document findings on Form F-192.477.

15. Refer to procedure P-192.711 for repairs options if repairs are needed and P-192.483 for remedial measures if it is determined additional protection is required.



The District Manager will begin an investigation into the causes of internal corrosion and determine:

- a. If the damage was caused by previous or present exposure to corrosive elements transported in the gas.
- b. If corrosive gas is being transported, take steps to eliminate corrosive elements.
- c. If a monitoring program is necessary.
- d. If introducing inhibitors is necessary.

Monitor Probes

1. Inform pipeline control center of planned activity.
2. Use personal protective equipment and clothing.
3. Locate probe site. Remove port cap at this time.
4. The data recorder has an adaptor that fits into the prongs (or terminals) on the probe. Connect the proper cord to the appropriate terminal of the probe. The cords are clearly marked on the ends. Turn the Data Logger on by pressing the "on" button firmly. An audible sound should be detected indicating the machine is "on". The data logger will prompt you through the steps required to obtain an accurate reading.
5. Depending on the Data Logger manufacture, you may need to document the reading indicated on LED, or the data may be stored in the Data Logger for later retrieval.
6. Locate probe site. Replace port cap at this time.
7. Readings indicate the probe needs inspection and/or replacement.
8. Does probe need to be removed?
 - a) No –Continue with step 9.
 - b) Yes - Probe replacement (if required): Seek assistance from appropriate personnel for additional investigation and corrective actions before removal. Consult manufacture recommendations or company O&M Manual for proper replacement.
9. Inform pipeline control center that planned activity is completed or further maintenance is required.
10. Document findings on Form F-192.477.
11. Refer to procedure P-192.711 for repairs options if repairs are needed and P-192.483 for remedial measures if it is determined additional protection is required.



Description	This procedure describes the steps taken to protect pipelines and their components that are exposed to the atmosphere from external corrosion.
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Note: In the state of Texas, 'atmospheric corrosion' means aboveground corrosion caused by chemical or electrochemical reaction between a pipe material, usually a metal, and its environment, that produces a deterioration of the material."

**Regulatory
Applicability**

All aboveground pipelines or portions of a pipeline

- ☒ Regulated Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☒ Regulated Gathering Pipelines (Type B)
- ☒ Regulated Distribution Pipelines

NOTE: Except for portions of pipelines in offshore splash zones or soil-to-air interfaces, pipelines do not have to be protected if the operator can demonstrate by test, investigation or experience appropriate to the environment of the pipeline that corrosion will only be a light surface oxide or will not affect the safe operation of the pipeline before the next scheduled inspection.

Frequency

- Provide protection against atmospheric corrosion as needed.

Reference

49 CFR Part 192.479 *Atmospheric Corrosion Control: General*
16 TAC 8.203 **Supplemental Regulations**
LA Title 43 Part XIII 2131 *Atmospheric Corrosion Control: General*

**Forms / Record
Retention**

None



**Related
Specifications**

None

**OQ Covered
Task**

0991	Coating Application and Repair: Brushed or Rolled
1001	Coating Application and Repair: Sprayed

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Atmospheric Coating Requirements

Each pipeline exposed to the atmosphere must be cleaned and coated with a coating material suitable for the prevention of atmospheric corrosion. Except for portions of pipeline in offshore splash zones or soil-to-air interfaces, pipelines exposed to the atmosphere need not be coated where test, investigation or experience appropriate to the environment indicates that corrosion will:

- Be a light surface oxide only; and
- Not affect the pipeline's safe operation before the next scheduled inspection.

Document testing, investigation or experience justification where it is determined that coatings are not needed and secure approval from the Operations Manager, or designated representative, for any pipeline facility that will not require coating in accordance with the criteria above.

Prevention against Atmospheric Corrosion

Note: Prior to abrasive blasting, the following steps must be taken to contain and capture blast residue in the vicinity of the work:

Fugitive Emissions Containment

1. Prior to abrasive blasting, steps must be taken to contain and capture blast residue in the vicinity of the work.
2. Tarps 20 ft. x 30 ft. or larger shall be placed over plastic before any blasting begins. The purpose of the plastic is to contain fine rust/paint particles while tarps contain coarse spent blast media.
3. At night, tarps should be pulled back from the pipeline facility to cover spent blast media and to keep it dry and easier to handle during cleanup.
4. Tank shells and/or other pipeline facilities may require containment screens in accordance with local or state fugitive emissions laws. The engineer must ensure that the company is in compliance with these laws and regulations.
5. If containment screens are required, 95-100% of the blasting area shall be covered to contain the dust and blast media.
6. No blasting shall be performed within 10 feet of the edge of containment screens.
7. Containment screen(s) design and installation shall be approved by the engineer prior to abrasive blasting.

Surface Preparation

The performance of any paint system relies on its adhesion to the steel surface, which is the direct result of adequate surface preparation.



Abrasive Blasting

1. All surfaces to be abrasively blasted should be evaluated to see if they must first be power washed to remove dirt, chalk, oils, grease, salts and other contaminants. These contaminants can be driven into the steel by mechanical cleaning or sandblasting that can cause premature failure of the newly applied paint system.
2. Abrasive blasting shall be in accordance with NACE #3 or SSPC #6 specifications for commercial blast. These specifications are defined as a surface from which all oil, grease, dirt, rust scale and foreign matter have been completely removed. Mill scale and old paint have been removed except for slight shadows, streaks or discolorations caused by rust stain. If the surface is pitted, slight residues or rust/paint can be found in the bottom of the pit.
3. NACE #3 or SSPC #6 visual specifications shall be the only reference used to measure surface preparation compliance. An anchor profile of 1.5 MILS shall be achieved on all surfaces that are blasted.
4. The compressed air used for abrasive blasting shall be free of detrimental amounts of water and oil. Adequate traps and separators shall be provided at the compressor.
5. All gauges, gauge boards, nameplates, valve stems, etc. shall be covered during blasting and painting processes to prevent damage. All equipment damaged by blasting or painting shall be repaired or replaced at the contractor's expense. Upon completion of the painting process, all protective coverings shall be removed by the contractor.
6. Prior to abrasive blasting, all detrimental amounts of oils, grease, and organic matter shall be removed from the surface by solvents or detergent washing. The engineer shall determine when solvent cleaning of the surface is necessary.
7. Blasting shall be done with media of mineral sand, or equal, that is no larger than that passing through a 16 mesh screen, and no smaller than that passing through a 40 mesh screen. The media shall be clean, dry, and free of extraneous matter. The media must be approved by the engineer before blasting begins.
8. Galvanized steel, brass, aluminum or stainless steel surfaces shall not be abrasive blasted.

Power Washing

1. Existing painted/coated surfaces that have good adhesion to the substrate may be power washed and scrubbed to remove chalk, dirt, and contaminants.
2. Water pressure is dependent on job requirements, but will normally be 400 - 500 PSI with a cleaning detergent added to the water.
3. The cleaning agent shall be trisodium sulfate or common liquid dish washing soap. Both agents are biodegradable and accepted by the EPA.
4. The areas power washed shall subsequently be rinsed thoroughly with clean water and allowed to dry prior to any coating application.



5. To check for chalk and contaminant removal from previously painted surfaces that have been power washed and rinsed, rub the area with a clean black cloth on the surface. Any chalk that remains will be detected on the black cloth.

Painting/Coating Application

1. Application shall be in accordance with the paint manufacturer's recommendations.
2. All sand and dust from the blasting operations shall be removed from surfaces before the painting application is begun.
3. Surface preparation or painting shall not be conducted when the relative humidity of the surrounding air meets or exceeds 85%, or when the ambient temperature is below 50° F and the dew point is within 5° F of the surface temperature.
4. A sling psychrometer, or equal, shall be used by the engineer to measure the wet and dry bulb temperatures of the surrounding air. These temperatures shall be converted to relative humidity. These measurements shall be taken prior to all surface preparation and painting procedures.
5. The sequence to be followed in the painting process shall be such that minimum damage to the finish coating will result.
6. All areas of surface preparation shall be kept "squared" up and coated the same day or sooner with one coat of primer to avoid surface contamination.
7. Corners and decorative breaks or protrusions will be coated in a manner to maintain specified film build on all edges, corners, and joints.
8. Areas coated are to be checked by the contractor at least once every 50 sq. ft. for proper film thickness with a wet film thickness gauge.
9. Primer shall not be applied closer than 2-4 inches to a non-blasted area. All subsequent blasting operation shall not result in sand particles becoming embedded in the coating.
10. All drops on tanks shall be completed in their entirety before proceeding to the adjacent areas.
11. The contractor shall ensure uniformity of texture throughout entire job. Abraded or otherwise marred spots shall be blended to surrounding areas.
12. Specified film thickness shall be stated as "MILS D.F.T." signifying acceptable dry film thickness per coat.
13. The primers, intermediate coat, and top coat shall be painted/coated with material manufactured no more than 12 (twelve) months prior to work commencing.
14. The prime coat shall be an alkyd rust-inhibitive primer of red or gray color. Primer shall be applied in one-coat, 4.0 - 6.0 MILS wet and 2.0 - 3.0 MILS dry. Allow adequate drying time between prime coat and the first finish coat.
15. All sandblasted surfaces shall be primed immediately following proper surface preparation.



16. All primers and finish coats shall be applied by roller on large flat areas and brush in areas impractical for rollers.
17. Following is a recommended procedure for maintenance painting. The engineer may approve an alternative system.
18. The bottom 1', cone roof, top side of wind girders and areas of water pooling or condensation forming shall be painted with two coats of a hi-solids epoxy (white in color) applied at 4 -5 dry MILS per coat as a prime, intermediate or finish coat. Allow 24 hours drying time between the two coats of epoxy.
19. The intermediate/first finish coat shall be a controlled chalking alkyd structural enamel or equal paint white in color. This first finish coat shall be applied 6 - 8 MILS wet and 3 - 4 MILS dry. Allow adequate drying time between subsequent coats.
20. The final/second finish coat shall be a controlled chalking alkyd structural enamel or equal paint white in color. The final coat shall be applied with 6 - 8 MILS wet and 3 -4 MILS dry.

Paint Maintenance

1. A sound, totally intact, previously applied paint/coating requires a minimum of surface preparation prior to maintenance painting. GOOD PAINT SHOULD NOT BE BLASTED OFF.
2. A careful examination of old coatings is a necessary step in deciding on an adequate routine of surface preparation.
3. A close visual inspection followed by the "knife test" is recommended to determine the amount of flexibility in the old coating. Brittle coating indicates its susceptibility to thermal shock and should be removed.
4. The degree of performance of the newly applied coating is directly proportionate to the performance value of the old coating over which it is applied.
5. Some coatings require an etch pattern prior to recoating. If required, a very fine abrasive - approximately 60 mesh - is recommended, which will eliminate the impact of large grit particles on the painting/coating to be saved.
6. Touch-up painting of bare spots requires application of an extremely low viscosity, high aromatic highly penetrating primer to the surface that will permeate any edge areas of poor adhesion in the feathered areas. The primer shall be a low viscosity, low molecular weight material, thoroughly compatible with both the existing coating and the steel surface, and that has high wetting characteristics for each.
7. Mechanical application, preferably by brush, will aid in the wetting and penetration of the primer into the porosity of the feathered section of the coating.
8. Subsequent intermediate coat and final coats shall be applied in accordance with the application procedure described previously.



Waste Disposal

1. The removal by abrasive blasting of most paints/coatings creates a waste material that has to be disposed of in accordance with EPA regulations. The containment and disposal of this material shall be coordinated with the company's compliance supervisor on each project.
2. The blast media shall be collected on tarps and/or plastic sheets and dumped into clean 55-gallon drums with lids and sealing rings at the job site. Each drum shall be labeled in accordance with EPA rules and regulations. On large jobs, a properly labeled roll off trailer may be used to dump the spent blast media. The roll off shall be lined with plastic and covered with a tarp to prevent rain water from entering the trailer.
3. Spent abrasive material is classified as hazardous when it contains more than 5 PPM of leachable lead or chromium compounds as determined by the EPA's toxicity characteristic leaching procedure (TCLP). This test shall be conducted on each project generating spent blast media except new construction blasting.
4. Spent blast media that is not hazardous according to EPA guidelines may be hauled to a local landfill approved by the company's environmental supervisor.



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Description	To establish the procedures for inspection and maintenance of above-ground metallic pipeline systems for atmospheric corrosion.
Regulatory Applicability	All above-ground metallic gas pipelines <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	Onshore other than a "Service Line": At least once every 3 calendar years, but with intervals not exceeding 39 months OnShore "Service Line": At least once every 5 calendar years, but with interval not to exceed 63 months unless atmospheric corrosion was found during the previous inspection. When atmospheric corrosion is found on a service line, the next inspection is to be conducted within 3 calendar years not to exceed 39 months.
Reference	49 CFR 192.481 <i>Atmospheric Corrosion Control: Monitoring</i> LA Title 43 Part XIII 2133 <i>Atmospheric Corrosion Control: Monitoring</i>
Forms / Record Retention	WTG 1202 <i>Atmospheric Corrosion Survey / Life of Pipeline System</i> Atmospheric Corrosion Survey Service Lines / Two Survey Cycles or 5 Year Whichever is GreaterF-192.709 <i>Repair Work Order / Life of Pipeline System</i>
Related Specifications	None
OQ Covered Task	0141 <i>Visual Inspection for Atmospheric Corrosion</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Inspect all aboveground piping.
2. If visual inspection shows evidence of corrosion damage or other conditions warrant, conduct non-destructive testing.
3. Inspect the soil/air interfaces, or transition zone of pipe entering the ground or water to confirm that it is properly coated to prevent the penetration of water between the pipe and the coating. Ensure special attention is paid to areas under thermal disbonded coating, pipe supports, splash zones, deck penetrations, and spans over water.
4. If a condition is observed where moisture may be retained between the coating and pipe, remove the coating, inspect the pipe, evaluate the severity of any present corrosion, take remedial action (See procedure P-192.483), and recoat the pipe prior to the next inspection. (See Procedure P-192.461 or P-192.479.)
5. Complete Form WTG 1202.
6. Issue a repair order (F-192.709) to handle any required repairs.
7. Determine if any safety-related conditions are present, and report per procedure #P-191.23.
8. Maintain a continuing program of painting based upon the results of the external inspection program. Refer to procedure P-192.479 for painting requirements.
9. If the pipe wall loss exceeds 10% of the nominal wall thickness, review the MAOP for possible revision and/or recommend pipeline repair requirements. (See procedure P-192.619.)



Description	To prescribe the minimum steps required to remediate cathodic protection.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines Installed after August 1, 1971	
Frequency	When corrosion is found on cathodically protected pipe.	
Reference	49 CFR 192.483	<i>Remedial Measures: General</i>
	49 CFR 192.485	<i>Remedial Measures: Transmission Lines</i>
	LA Title 43 Part XIII 2135	<i>Remedial Measures: General</i>
	LA Title 43 Part XIII 2137	<i>Remedial Measures: Transmission Lines</i>
Forms	F-192.455	<i>Installation of Cathodic Protection System</i>
Related Specifications	ASME/ANSI B31G AGA Pipeline Research Committee Project PR-805 (with RSTRENG disk)	
OQ Covered Task	0081	<i>Install Cathodic Protection Electrical Isolation Devices</i>
	0091	<i>Troubleshoot In-service Cathodic Protection Systems</i>
	(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

1. Have an engineer or qualified individual determine what changes need to be made in the cathodic protection system.
2. Use ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk) to determine the strength of the pipe based on the actual remaining wall thickness.
3. Replace sections of pipe that have areas of general corrosion (corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion) and a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline.

NOTE: These areas may be repaired by a method that reliable engineering tests and analyses have shown can permanently restore the serviceability of the pipe.

4. Replace or repair sections of pipe that have areas of localized corrosion pitting to a degree that leakage might result.

NOTE: If repair or replacement is not performed, the operating pressure must be reduced to commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

5. Ensure the pipe being used in the replacement has a properly prepared surface, is provided with an external protective coating that meets the requirements of 49 CFR 192.461 (See procedure P-192.461), and is cathodically protected in accordance with the requirements of 49 CFR Subpart I. Follow procedure P-192.455 for installation requirements.
6. Repair any other areas of pipe that show extensive corrosion.
7. Make appropriate changes to the cathodic protection system in an attempt to stop the corrosion. Install any additional equipment according to procedure P-192.455.



Description	To prescribe the minimum steps required to remediate cathodic protection for distribution systems installed prior to August 1, 1971, and under mandatory or voluntary cathodic protection.	
Regulatory Applicability	<input type="checkbox"/> Regulated Transmission Pipelines <input type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines Installed before August 1, 1971	
Frequency	When active corrosion is found.	
Reference	49 CFR 192.483	<i>Remedial Measures: General</i>
	49 CFR 192.487	<i>Remedial Measures: Distribution Lines</i>
	49 CFR 192.465(d)	<i>Remedial Action to Correct Defects</i>
Forms	F-192.455	<i>Installation of Cathodic Protection System</i>
Related Specifications	ASME/ANSI B31G AGA Pipeline Research Committee Project PR-805 (with RSTRENG disk)	
OQ Covered Task	0081	<i>Install Cathodic Protection Electrical Isolation Devices</i>
	0091	<i>Troubleshoot In-service Cathodic Protection Systems</i>
	(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

1. Identify the offending segment of pipeline where “active corrosion” exists. (Active corrosion is defined as continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.
2. Make appropriate repairs/improvements to the cathodic protection system in an attempt to control the corrosion. Install any additional facilities according to procedure P-192.455.
3. If attempts to repair/improve the cathodic protection system are infeasible or prove unsuccessful, replace the offending segment of steel pipe with polyethylene pipe.



Description	This procedure is used to establish guidelines for pressure testing steel pipelines.		
Regulatory Applicability	<div><input checked="" type="checkbox"/> Transmission Pipelines</div> <div><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A)</div> <div><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B)¹</div> <div><input checked="" type="checkbox"/> Distribution Pipelines</div>		
Frequency	Prior to operating a new pipeline or returning to service a pipeline that has been relocated or replaced, pressure test the line according to the requirements of this procedure to substantiate the MAOP (See procedure P-192.619) and locate and eliminate each potentially hazardous leak.		
Reference	49 CFR 192.501	Scope	
	49 CFR 192.503	General Requirements	
	49 CFR 192.505	Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30% or More of SMYS	
	49 CFR 192.507	Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30% of SMYS At or Above 100 psi	
	49 CFR 192.509	Test Requirements for Pipelines to Operate Below 100 psi	
	49 CFR 192.511	Test Requirements for Service Lines	
	49 CFR 192.515	Environmental Requirements	Protection and Safety
	49 CFR 192.517	Records	
Reference (Cont'd)			

Forms / Record F-192.517 *Pipeline Pressure Test Record / Life of Pipeline System,*

¹ If the line is new, replaced, relocated or changed.



Retention	<i>Keep most current copy of records</i>
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Related Specifications	None
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OQ Covered Task	0561	<i>Pressure Test – Non-Liquid Medium – MAOP Less Than 100 PSI</i>
	0571	<i>Pressure Test – Non-Liquid Medium – MAOP Greater Than or Equal to 100 PSI</i>
	0581	<i>Pressure Test – Liquid Medium</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

NOTE: A job-specific procedure must be developed to cover the items discussed in this procedure.

General Requirements

1. The test medium used must be liquid, air, natural gas or an inert gas that is compatible with the pipe material, relatively free of sedimentary materials, and nonflammable (except for natural gas).
2. Unless otherwise noted in this procedure, the following maximum hoop stress limitations apply:

Class Location	Maximum hoop stress allowed as percentage of SMYS	
	Natural Gas	Air or Inert Gas
1	80	80
2	30	75
3	30	50
4	30	40

3. Although each joint used to tie in a test segment of the pipeline is excepted from the specific requirements of this procedure, each non-welded joint must be leak tested to not less than its operating pressure.
4. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required as long as the manufacturer of the component certifies that –
 - a) the component was tested to at least the pressure required for the pipeline to which it is being added;
 - b) the component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
 - c) The component carries a pressure rating established through applicable ASME.ANSI, MSS specifications, or by unit strength calculations as described in 49 CFR 192.143.
5. Safety is the primary consideration during planning and completion of all pressure test. All associated equipment and material must be secured or anchored to prevent uncontrolled pressure releases.



Strength Test Requirements for Steel Pipe Operating at a Hoop Stress >30%

1. In a Class 1 or Class 2 location, if a building(s) intended for human occupancy exists within 300 feet of a pipeline whose design hoop stress level is 30% or more of SMYS, the test pressure must be a minimum of 1.25 times MAOP (see P-192.619). In no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. If an inert gas or air test is to be conducted, the building(s) must be evacuated while the hoop stress level exceeds 50% of SMYS. If building(s) cannot be evacuated, the piping must be hydrostatically tested.
2. In Class 1 or Class 2, each compressor station, regulating station and measuring station must be tested to at least Class 3 test requirements of a minimum of 1.50 times MAOP (see P-192.619)
3. The test pressure must be maintained throughout the part of the system being tested for eight (8) hours. However, fabricated units and short sections of pipe for which a post installation test is impractical, a pre-installation strength test may be conducted by maintaining the pressure at or above the test pressure for at least four (4) hours.

Strength Test Requirements for Steel Pipe Operating at a Hoop Stress <30% and At or Above 100

1. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.
2. If during the test the segment is to be stressed to 20% or more of SMYS and natural gas, inert gas or air is the test medium.
3. A leak test must be performed at a pressure between 100 psi gauge and the pressure required to produce a hoop stress of 20% or SMYS; or
4. The line must be checked for leaks using Leak Detection equipment Pipeline Inspection used while the hoop stress is held at approximately 20% of SMYS. (The TRRC recently gave approval to WTG to use aerial leak surveying for this task).
5. The pressure must be maintained at or above the test pressure for at least one (1) hour.
6. For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation hydrostatic pressure test must be conducted in accordance with the requirements of this section.

Test requirements for Pipelines to Operate Below 100 psig.

1. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.
2. Each main that is to be operated at less than 1 psig must be tested to at least 10 psig.
3. Each main that is to be operated at or above 1 psig must be tested to at least 90 psig.
4. Each test must be a minimum of 1 hour.



Test Requirements for Service Lines (Other than Plastic)

1. If feasible, the service line connection to the main must be included in the test. If this is not feasible, it must be given a leakage test at the operating pressure when placed in service.
2. Each segment of a service line intended to be operated at a pressure of at least 1 psi gauge but not more than 40 psi gage must be given a leak test at a pressure not less than 50 psi gauge.
3. Each segment of a service line intended to be operated at pressures of more than 40 psi gauge must be tested to at least 90 psi.

NOTE: Each segment of a steel service line stressed to 20% or more of SMYS must be tested in accordance with 49 CFR 192.507.

Environmental Protection and Safety Requirements

1. Every reasonable precaution must be taken to protect employees and the general public during testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50% of SMYS, all practical steps shall be taken to keep people not working on the testing operations outside of the testing area until the pressure is reduced to or below the MAOP.
2. The test medium shall be disposed of in a manner that will minimize damage to the environment.

Records

1. A record of each test performed under 49 CFR 192.505 and 507 (steel pipelines operating above 100 psi) shall be maintained and kept for the useful life of the pipeline.
2. The record must contain: (Complete Form F-192.517 or equivalent documentation)
 - a) The operator's name, the name of the operator, employee responsible for making the test, the name of the test company used;
 - b) Test medium used;
 - c) Test pressure;
 - d) Test duration;
 - e) Pressure recording charts, or other record of pressure readings;
 - f) Elevation variations, whenever significant for the particular test; and
 - g) Leaks and failures noted and their disposition.

Records of pressure tests performed under 49 CFR 192.509 and 192.511 must be maintained for the useful life of the pipeline.



Transmission lines: Spike hydrostatic pressure test.

1. *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.
 - a) The test must use water as the test medium.
 - b) The baseline test pressure must be as specified in the applicable paragraphs of §192.619(a)(2) or §192.620(a)(2), whichever applies.
 - c) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in §192.505.
 - d) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.
2. *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with §192.18 and must include the following information:
 - a) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
 - b) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
 - c) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;
 - d) Assessment techniques and acceptance criteria;
 - e) Remediation methods for assessment findings;
 - f) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
 - g) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and
 - h) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert



Description	This procedure is used to establish guidelines for pressure testing plastic pipelines.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Gathering Pipelines <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	Prior to operating a new pipeline or returning to service a pipeline that has been relocated or replaced, pressure test the line according to the requirements of this procedure to substantiate the MAOP (See procedure P-192.619) and locate and eliminate each potentially hazardous leak.	
Reference	49 CFR 192.501	<i>Scope</i>
	49 CFR 192.503	<i>General Requirements</i>
	49 CFR 192.513	<i>Test Requirements for Plastic Pipelines</i>
	49 CFR 192.515	<i>Environmental Protection and Safety Requirements</i>
	49 CFR 192.517	<i>Records</i>
Forms / Record Retention	F-192.513	<i>Plastic Pipeline Pressure Test Record / Life of Pipeline System</i>
	WTG-1400	<i>Project Report Form / Life of Pipeline System</i>
Related Specifications	None	
OQ Covered Task	0561	<i>Pressure Test – Non-Liquid Medium – MAOP Less Than 100 PSI</i>
	0571	<i>Pressure Test – Non-Liquid Medium – MAOP Greater Than or Equal to 100 PSI</i>
	0581	<i>Pressure Test – Liquid Medium</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

NOTES:

- Written job-specific pressure test procedure/instructions to cover the items discussed in this procedure are suggested for complex tests.
- During the test the temperature of the thermoplastic material may not be more than 100° F or less than 35° F.
- Any leak discovered during testing must be repaired before final testing is complete.

Test requirements for Plastic Pipeline Mains.

1. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.
2. Pipeline pressure tests are not to exceed the following maximum pressures:

Grade	Type	Maximum Test Pressure (psig)
SDR 11	4710	150
SDR 11	3408	150
SDR 11	2406	120
SDR 17	3408	96

Note: The test pressure must be at least 150% of the Maximum Operating Pressure or 50 psig; whichever is greater. The maximum test pressure may not be more than 2.5 times the pressure determined under CFR 192.121 at a temperature not less than the pipe temperature during the test.

Test Requirements for Plastic Service Lines

1. If feasible, the service line connection to the main must be included in the test. If this is not feasible, it must be given a leakage test at the operating pressure when placed in service.
2. If plastic service lines are to be tested at the same time as the distribution mainline, operating personnel completing the test must ensure that all EFV's included in the test are in the open position and not disrupting flow to the downstream side of the EFV. To do this, the operating personnel will need to either test the service for adequate flow or check pressure at the riser valve once the mainline is brought up to the proper test pressure.



3. Pipeline pressure tests are not to exceed the following maximum pressures:

Grade	Type	Maximum Test Pressure (psig)
SDR 11	4710	150
SDR 11	3408	150
SDR 11	2406	120
SDR 17	3408	96

Note: The test pressure must be at least 150% of the Maximum Operating Pressure or 50 psig; whichever is greater. However, the maximum test pressure may not be more than 3 times the design pressure of the pipe.

Environmental Protection and Safety Requirements

1. Every reasonable precaution must be taken to protect employees and the general public during testing. All practical steps shall be taken to keep people not working on the testing operations outside of the testing area until the test is complete and pipeline segment pressure is return to normal operations.
2. The test medium shall be disposed of in a manner that will minimize damage to the environment.

Records

1. Each District/Division Manger shall make, and retain for the useful life of the pipeline, a record of each test performed under these requirements. The record must contain the following information:
 - a) Name of employee or Contractor Employee that conducted the test.
 - b) Test medium used.
 - c) Test pressure and temperature.
 - d) Test duration.
 - e) Elevation variations, if significant.
 - f) Leaks and failures and the root cause of such.



Description	To outline the minimum requirements for increasing the maximum allowable operating pressure (MAOP) in pipelines.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	As needed	
Reference	<div>49 CFR 192.551 <i>Scope</i></div> <div>49 CFR 192.553 <i>General Requirement</i></div> <div>49 CFR 192.555 <i>Uprating to a Pressure that Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines.</i></div> <div>49 CFR 192.557 <i>Uprating: Steel Pipelines to a Pressure that will Produce a Hoop Stress Less than 30 Percent of SMYS; Plastic, Cast Iron, and Ductile Iron Pipelines.</i></div> <div>49 CFR 192.619 <i>Maximum Allowable Operating Pressure: Steel and Plastic Pipelines</i></div> <div>LA Title 43 Part XIII 2501 <i>Scope</i></div> <div>LA Title 43 Part XIII 2503 <i>General Requirement</i></div> <div>LA Title 43 Part XIII 2505 <i>Uprating to a Pressure that Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines.</i></div> <div>LA Title 43 Part XIII 2507 <i>Uprating: Steel Pipelines to a Pressure that will Produce a Hoop Stress Less than 30 Percent of SMYS; Plastic, Cast Iron, and Ductile Iron Pipelines.</i></div> <div>LA Title 43 Part XIII 2719 <i>Maximum Allowable Operating Pressure: Steel and Plastic Pipelines</i></div>	
Forms / Record Retention	None / Life of Pipeline System	
Related Specifications	None	



OQ Covered Task	0381	<i>Spring Loaded Pressure Regulated Device – Inspection and Testing, Prevention and Corrective Maintenance</i>
	0391	<i>Pilot Operated Pressure Regulated Device – Inspection and Testing, Prevention and Corrective Maintenance</i>
	0401	<i>Controller Type Pressure Regulated Device – Inspection and Testing, Prevention and Corrective Maintenance</i>
	0221	<i>Inspect, test, and Maintain Sensing Devices</i>
	1311	<i>Inspect Pipeline Surface Conditions – Patrol Right – of – Way or Easement</i>
	1261	<i>Walking Gas Leakage Survey</i>
	1271	<i>Mobile Gas Leakage Survey</i>
	1281	<i>Mobile Gas Leakage Survey</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Establish a written uprating plan that is in accordance with the requirements outlined in this procedure for each segment of pipeline to be uprated. The written uprating plan must be approved by Operations Manager or compliance Department or District Manager.

Uprating Requirements

1. No segment of pipeline may be subjected to an operating pressure that will produce a hoop stress of 30% or more of SMYS and that is above the established maximum allowable operating pressure unless it is in accordance with the following:
 - a) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:
 - i) Review the design, operating and maintenance history, and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this procedure.
 - ii) Perform a leakage survey and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, it is monitored during the pressure increase and it does not become potentially hazardous.
 - iii) Make any repairs, replacements, or alternations in the segment of pipeline that are necessary for safe operation at the increased pressure.
 - b) After complying with paragraph 1a above, the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970 may be increased to the highest pressure permitted in P-192.619, using as a test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).
 - c) After complying with paragraph 1a above, the maximum allowable operating pressure of a pipeline segment that does not qualify under paragraph 1b may be increase if at least one of the following requirements is met:
 - i) The segment of pipeline is successfully tested in accordance with the requirements of part 192 Subpart J for a new line of the same material in the same location.
 - ii) The maximum allowable operating pressure of a pipeline segment in a Class 1 location that has not been previously pressure tested may be increased if:
 - (1) It is impractical to test it in accordance with the requirements of this part;
 - (2) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and
 - (3) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this procedure.
2. No segment of a steel pipeline may be subjected to an operating pressure that will produce a hoop stress of less than 30 percent of SMYS and that is above the established maximum allowable operating pressure unless it is in accordance with paragraphs a and b below.



Also, no segment of plastic pipeline may be subjected to an operating pressure that is above the established maximum allowable operating pressure unless it is in accordance with paragraph (a) below.

- a) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:
 - i) Review the design, operating, and maintenance history of the segment of pipeline.
 - ii) Perform a leakage survey and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, it is monitored during the pressure increase and it does not become potentially hazardous.
 - iii) Make any repairs, replacement, or alterations in the segment of pipeline that are necessary for safe operation at the increase pressure.
 - iv) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation
 - v) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure.
 - vi) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.
3. Ensure that a new MAOP cannot be exceeded in operation.
4. Conduct a series of incremental pressure increases that comply with:
 - a) 10 psi gauge increases; or
 - b) 25% of the total pressure increase, whichever results in the fewer number of increments.
5. At the end of each incremental increase, the pressure must be held constant while the entire segment is checked for leaks.
6. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure test conducted, in connection with the uprating.
7. A record of this uprating will be made and retained for the life of the pipeline segment. The mapping department will be notified of all changes of MAOP. These records must contain:
 - a) Copies of the design, operating and maintenance history records that were reviewed prior to testing.
 - b) All leak surveys and repairs made prior to testing.
 - c) Results of the incremental pressure tests conducted to uprate the pipeline and pressure recording charts or other records of pressure readings.
 - d) Elevation variations, whenever significant for the particular test.



- e) The name of the employee in charge of the test and the names of all who helped and what they did.
- f) All leak surveys made during the test.



Description	This procedure is used to review the Operations & Maintenance Manual and revise it as necessary.		
Regulatory Applicability	Operations & Maintenance Manual as well as company policies referenced within. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines		
Frequency	At least once each calendar year, not to exceed 15 months		
Reference	49 CFR 192.605(a) Procedural Manual for Operations, Maintenance and Emergencies LA Title 43 Part XIII 2705(a) <i>Procedural Manual for Operations, Maintenance and Emergencies</i>		
Forms / Record Retention	F-192.605(a)	Operations and Maintenance Manual Annual Review / 2 Years or Until Next Review Whichever is Longer	
Related Specifications	None		
OQ Covered Task	None		



Procedure Steps

1. Have personnel who are knowledgeable in pipeline operations and maintenance review the Operations & Maintenance Manual. This review is accomplished through the following activities:
 - a) Reviewing the contents of this Operation, Maintenance and Emergency (OME) Plan, including all procedures and forms used;
 - b) reviewing other Company manuals referenced in this manual;
 - c) reviewing Pipeline Specific Operations Manuals (PSOM);
 - d) reviewing job/project plans, by operating area supervisors or foremen; and
 - i) This review shall include actual observation of the work performed in the field, where applicable. The review shall determine the effectiveness and safety of the procedures used in normal operation or maintenance. Procedures must be modified where deficiencies are found.
 - e) Reviewing the regulatory required changes.
 - f) West Texas Gas' response in controlling abnormal operations will be reviewed. Any deficiencies to the response will be corrected through changes to written procedures; or through operator training; or both.
2. Document these reviews on form F-192.605(a).
3. The WTG Compliance Department is responsible for updating the manual using form F-192.605(a).
4. Update the revisions page in the manual. Other pages of this plan that are revised will carry a revision date at the bottom of the page.
5. Communicate and distribute the changes accordingly. Ensure appropriate parts are available at locations where O&M activities are conducted.
6. These reviews will be conducted by company supervision as well as outside specialist.



Description	This procedure is designed to make construction records, maps, and operations history available to appropriate operation personnel.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	As needed
Reference	49 CFR 192.605(b)(3) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> LA Title 43 Part XIII 2705(b)(9) <i>Procedural Manual for Operations, Maintenance and Emergencies</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	None



Procedure Steps

Safe and efficient operation of the pipeline system depends upon the availability of up-to-date maps, records, and operating history. The WTG Compliance Department is responsible for providing guidance on pipeline system records management and documentation. The *Specifics* Section of this manual lists general guidelines for gas pipeline safety records.

1. All information on pipeline maintenance or station modification shall be forwarded to the WTG Mapping Department as soon as possible after completion of the construction or repair, so that system maps and station drawings can be updated.
2. Once updated, a copy of the systems maps will be forwarded to the appropriate WTG District offices.
3. A copy of the station map will be posted in each station control building as appropriate and marked up pending update.

By following this procedure, each operating area will be assured of having a current record of the status of all piping and equipment within the area of their operating responsibility at all times.



Description	This procedure is designed to give general information for pipeline start-up and shutdown. Refer to the PSOM for specific procedures.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.605(b)(5) WTG P-192.629	<i>Procedural Manual for Operations, Maintenance and Emergencies</i> Purging of Pipeline
Forms / Record Retention	None	
Related Specifications	None	
OQ Covered Task	0301 <i>Manually Opening and Closing Valves</i> 1381 <i>Operate Gas Pipeline – Local Facility Remote Control Operations</i> 1401 <i>Operate Liquids Pipeline – Local Facility Remote Control Operations</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

Prior to starting-up or shutting down a pipeline; identify/notify affected external customers and appropriate internal company personnel.

Start-up

These procedures can be used on new pipeline installations or those pipelines that have been repaired.

1. If the pipeline has been pressure tested, remove any test medium; prepare the system to be purged of all air by the use of gas. Make sure all vents or valves used in the purging process are equipped with vents at least 6 feet above the ground. If necessary to protect the public, barricade the area, and stop vehicle traffic and other sources of ignition.
2. The flow of purge gas must be of sufficient pressure and volume to ensure a complete exclusion of air. The entire segment of pipeline and related equipment must be purged. (**REVIEW PIPELINE PURGING PROCEDURES IN P-192.629**).
3. After purging is completed, all open valves must be closed to prevent air from re-entering the system.
4. The pipeline and related equipment can now be pressured to the normal operating pressures. The pressurization process must be slow and steady. Pressure indicators must be monitored continuously to make certain that the system is not pressured above the established system MAOP.
5. Once the system is pressured to normal operating pressure, all valves, vents, regulators, etc. Should be checked for normal operations.

Shutdown

1. To begin the shutdown procedure, first close the upstream block valve and any additional pressure sources to stop the flow of gas into the pipeline. This will prevent over pressuring of a pipeline. Isolate the downstream block valve at the other end of the pipeline or segment.
2. If the gas pressure must be vented, precautions must be taken to prevent danger to the public, public property, our employees and our facilities. (**REVIEW PIPELINE PURGING PROCEDURES IN P-192.629**).



Description	The purpose of this procedure is to safely conduct scheduled and unscheduled maintenance of compressors and other equipment through the use of appropriate isolation procedures. These procedures minimize the chances of a release of hydrocarbons in the compressor building and an unexpected release of energy while personnel are working on equipment.
Regulatory Applicability	Maintenance activities on regulated compressors that requires that the equipment or line segment be taken out of service to perform the work safely. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input type="checkbox"/> Regulated Distribution Pipelines
Frequency	As needed
Reference	49 CFR 192.605(b)(6) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> LA Title 43 Part XIII 2705(b)(6) <i>Procedural Manual for Operations, Maintenance and Emergencies</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	0441 <i>Compressor Start Up and Shutdown - Manual</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Isolation of the Unit

1. Read and follow Lockout/Tag-out procedure.
2. Follow shut down procedure (See Procedure P-192.605(b)(7)).
3. Lockout/Tag-out suction and discharge valves.
4. Lockout and tag-out procedures shall be used on the following operations:
 - a) When opening systems, which normally contain process gas.
 - b) Any maintenance projects.
 - c) Any time internal maintenance is required.
 - d) When conducting electrical work.
5. Seal any open lines and accessory inlets to prevent entry of foreign material while servicing the unit.
6. Release all internal pressure in the unit piping and/or compressor before beginning any hot work or disassembling any part.
7. Lock and tag out pressure supply to engine starter
8. Attempt to start unit, testing for any stored energy.
9. Electrical Isolation of Skid, if required.
 - a. Turn off disconnects and install locks and tags per lockout/tag-out procedures.
 - b. Isolate utility powers by installing a breaker lock device and tag the lock per lockout/tag-out procedures.
10. For extended downtime periods due to major maintenance or for hot work, equipment and piping should be isolated from all pressure sources by installing blind flanges or flange plates, when possible.
11. If hot work is to be done, purge the equipment and/or piping until free of hydrocarbons as indicated by a gas test instrument.

Purging of the Unit (in the event the unit has been isolated and de-pressured)

1. Ensure all work has been completed and compressor components are installed as designed
2. Remove Locks and tags
3. Ensure blowdown valve is in the open position and bypass valve is in the closed position
4. Slowly open the suction valve until gas is flowing into the unit



5. Verify there is no gas leaking from compressor components or piping flanges
6. Purge until all air is removed or 100% gas level is attained
7. Open bypass valve to sweep bypass piping
8. Close blowdown valve
9. Open discharge valve
10. Open suction valve
11. Reconfirm there is no gas leaking from unit (compressor components and piping)

Isolation Procedure for a Compressor Station

1. To isolate station, follow the shutdown procedure.
2. Lock and Tag Out Suction Valve.
3. Lock and Tag Out Discharge valve
4. Lock and Tag Out Fuel supply
5. To assure station is isolated check gauges for pressure.

Purge of a Compressor Station

Due to the complexity of each Compressor station, a specific purging procedure is include with each station's ESD manual.



Description	Refer to the Pipeline Specific Operations Manual for specific Compressor Station Operating Procedures.		
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines		
Frequency	As needed		
Reference	49 CFR 192.605(b)(7) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> LA Title 43 Part XIII 2705(b)(7) <i>Procedural Manual for Operations, Maintenance and Emergencies</i>		
Forms / Record Retention	None / 1 Year		
Related Specifications	None		
OQ Covered Task	0441	Compressor Start-up and Shutdown-Manual	
(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)			



Procedure Steps

This procedure establishes the requirement for written instructions for starting, operating, and shutdown of natural gas compressor units and contributes to compliance with DOT Regulations 192.605(b)(7). It requires similar written instructions for all other complex equipment systems.

General

1. During start up, the maximum allowable operating pressure or MAOP of any piping shall not be exceeded.
2. During normal operation, the maximum allowable operating pressure or MAOP of any piping shall not be exceeded.
3. The operating speed on any reciprocating or centrifugal engine shall at no time exceed the manufacturer's maximum rated speed.
4. Simple equipment such as air compressors without external lube, or small pumps which are not part of a complex system, do not require written instructions.
5. Written procedures will contain pertinent manufacturer's instructions, and local station directives applicable to starting, operating, and shutting down of all pumps, compressor units, auxiliaries, and compressor station equipment. The location, together with local management, may add other checks to the procedures as suggested by experience.

Procedures

1. Develop written, detailed instructions for starting, operating, and shutdown of natural gas compressor units and other complex equipment prior to initial start-up. Assemble the instructions in a durable format or container to allow easy readability and to prevent damage or fading. Display applicable instructions prominently near the starting controls of each item of equipment.
2. Revise instructions as necessary to accommodate changes in equipment or operating conditions. Replace instructions when they become unreadable or damaged.
3. Take the following actions prior to starting any compressor unit or other complex equipment:
 - a. Notify all personnel to the immediate vicinity of the compressor unit or other complex equipment that is about to be started.
 - b. Ascertain that:
 - i. All critical operating variables such as suction and discharge pressure are within the safe limits of the units.
 - ii. All critical Compressor Station operating variables such as operating pressures, fluid levels, flow rates, and solution concentrations are within safe limits of the plant facilities.
 - iii. All personnel are clear of the equipment to be started.



- iv. All applicable valves are properly positioned for starting and operating.
 - v. All applicable safety alarm and shutdown devices are properly set to function.
 - vi. All electrical switches required for the starting sequence are properly positioned.
 - vii. Review all critical operating variables to assure that variables are within acceptable limits.
4. Follow detailed instructions for operating the equipment after it has been started to assure that the equipment is, at all times, within safe operating limits. In addition to those instructions, adhere to the following requirements:
- a. On all manually operated installations, daily operating log sheets shall be filled out with the critical operating variables noted and recorded on the log sheet or electronic record, at prescribed time intervals throughout the normal work hours
 - b. On all automatically controlled installations, the attendant shall periodically check all operating variables such as suction and discharge pressures, lube oil pressures, end temperatures, cooling water temperatures, fluid levels, flow rates, solution concentration and etc. during normal shift;
 - c. On all unattended installations, periodically check operations via SCADA equipment from remote location.
 - d. Unattended installations shall be equipped with sufficient alarm and shutdown devices to shut down the installation any time an operating variable exceeds the maximum safe limit set by design limitations or the equipment manufacturer. If an operating variable is noted to be approaching a safe limit, every effort shall be made to correct this situation before the variable exceeds the safe limit.
 - e. If any equipment cannot be maintained within safe operating limits or is malfunctioning to the extent that a potential hazard to personnel or property exists, it shall be shut down, and the reason for malfunctioning determined and corrected before initiating a restart.
5. Follow detailed instructions when shutting down a compressor or pumping unit or other complex equipment to assure that unsafe operating limit or potential hazard to personnel or property is not encountered during the shutdown.
- a. Reciprocating unit need not be blown down.
 - b. Where applicable, fuel and starting gas valves to the compressor engine shall be closed and maintained in a closed position until ready to start engine.
 - c. The compressor suction, discharge, and by-pass valves shall be positioned as outlined in the written operating procedures for shutdown.
6. Follow detailed instructions when removing liquids from station piping to assure that potential hazard to personnel or property is not encountered during liquid removal.



- a. Ensure all personnel have been notified and no work is being performed at the station tank.
- b. Verify the location of the valve to be used for liquid removal.
- c. Slowly open valve just far enough to achieve flow. Do not leave the valve unattended.
- d. Close valve when liquid removal is completed.
- e. Operating a vehicle in the proximity of the liquids tank during liquids removal is prohibited.

Records

1. Compressor station daily log sheets or a SCADA operating log shall be completed as applicable.
2. Gas compressor log sheets, at manned units, shall include suction and discharge temperatures and pressures. Retain these records for 12 months.
3. Use an electronic scheduler if available to ensure start-up and shutdown instruction reviews. If no electronic scheduler is available, the time intervals for these reviews are to be determined by the personnel in charge of the compressor station.



Description	To periodically review the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operations and maintenance, and to modify the procedures when deficiencies are found.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	Periodically as needed
Reference	49 CFR 192.605(b)(8) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> LA Title 43 Part XIII 2705(b)(8) <i>Procedural Manual for Operations, Maintenance and Emergencies</i>
Forms / Record Retention	F-192.605(b)(8) <i>Review of Work Done by Operator Personnel / 2 Years or Until Next Review whichever is Longer</i>
Related Specifications	None
OQ Covered Task	None



Procedure Steps

1. Annually, the WTG Compliance Department will develop a rotating schedule of the procedures to be reviewed by each individual District Manager. This review shall be documented on Form F-192.605(b)(8).
2. After completing the review, the form should be forwarded to the WTG Compliance Department for review.
3. The WTG Compliance Department will incorporate any approved procedure revisions as defined in the Management of Change process.
4. Below is a list of the procedures identified by WTG as normal operations and maintenance activities:
 - a) P-192.273, P-192.281, P-192.319, P-192.459, P-192.461, P-192.465(a), P-192.465(b), P-192.605(b)(5), P-192.605(b)(6), P-192.605(b)(7), P-192.605(b)(9), P-192.613, P-192.625, P-192.627, P-192.629, P-192.705, P-192.706, P-192.706(b), P-192.711, P-192.739, P-192.745, P-192.749



Description	This procedure was designed to develop safety practices to protect personnel from the hazards of unsafe accumulations of vapors or gas when working in excavated trenches.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	As required for excavation
Reference	49 CFR 192.605(b)(9) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> OSHA regulation 29 CFR 1926.650 Subpart P
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	None



Procedure Steps

1. Ensure that communications between personnel in the trench and on the ground are possible.
2. Ensure excavated or other materials are at least 2 feet from the edge of the trench. Surface encumbrances (trees, boulders, etc.) that may create a hazard to employees involved in excavation work need to be removed or secured.
3. Determine if a confined space entry permit is required. If so, ensure all applicable work is covered by the permit.
4. Prior to beginning work in the trench and on a periodic basis while work is being performed, test for an oxygen deficient atmosphere containing less than 19.5% oxygen and unsafe accumulations of vapor (concentration of flammable gas in excess of 20% of the lower flammable limit (LEL) of the gas) or gas. Use SCBA as appropriate.
5. Minimize water accumulation in trenches as necessary. This may be done with diversion ditches, dikes, or other suitable means.
6. Use devices such as stop logs or chocks to prevent mobile equipment from accidentally entering the excavation. When possible, the grade in such areas will slope away from the excavation.
7. Provide an exit such as a sloped cut-out, ladder or steps in trenches that are 4 feet deep or more. These should be located so that no more than 25 feet of lateral travel is required [See OSHA 1926.651(c)(2)]. Provide rescue harnesses and lines as appropriate.
8. When performing rock excavation, use either a jackhammer or a hydro-hammer to remove rock from under the pipe. Explosives may be used if the ditch is new or if the line in the ditch is not loaded. Explosives will only be used under the approval of the Manager of Engineering. For further information and guidelines on using explosives, refer to OSHA 1926.650, Subpart U.
9. Shore, lay back to a stable slope, or provide some other equivalent means of protection where personnel may be exposed to moving ground or cave-ins when the trench is more than 5 feet deep. This protection will also be provided in trenches less than 5 feet deep if soil conditions so dictate. Refer to the diagram on the next page as a guide in sloping banks. Trenches will be shored as follows:
 - a) Unstable or Soft Soil - (5 feet or more in depth)

Sides of the trench will be shored, sheeted, braced, sloped, or otherwise supported by means of sufficient strength to protect the personnel working with them.
 - b) Hard or Compact Shell - (5 feet or more in depth and 8 or more feet in length)

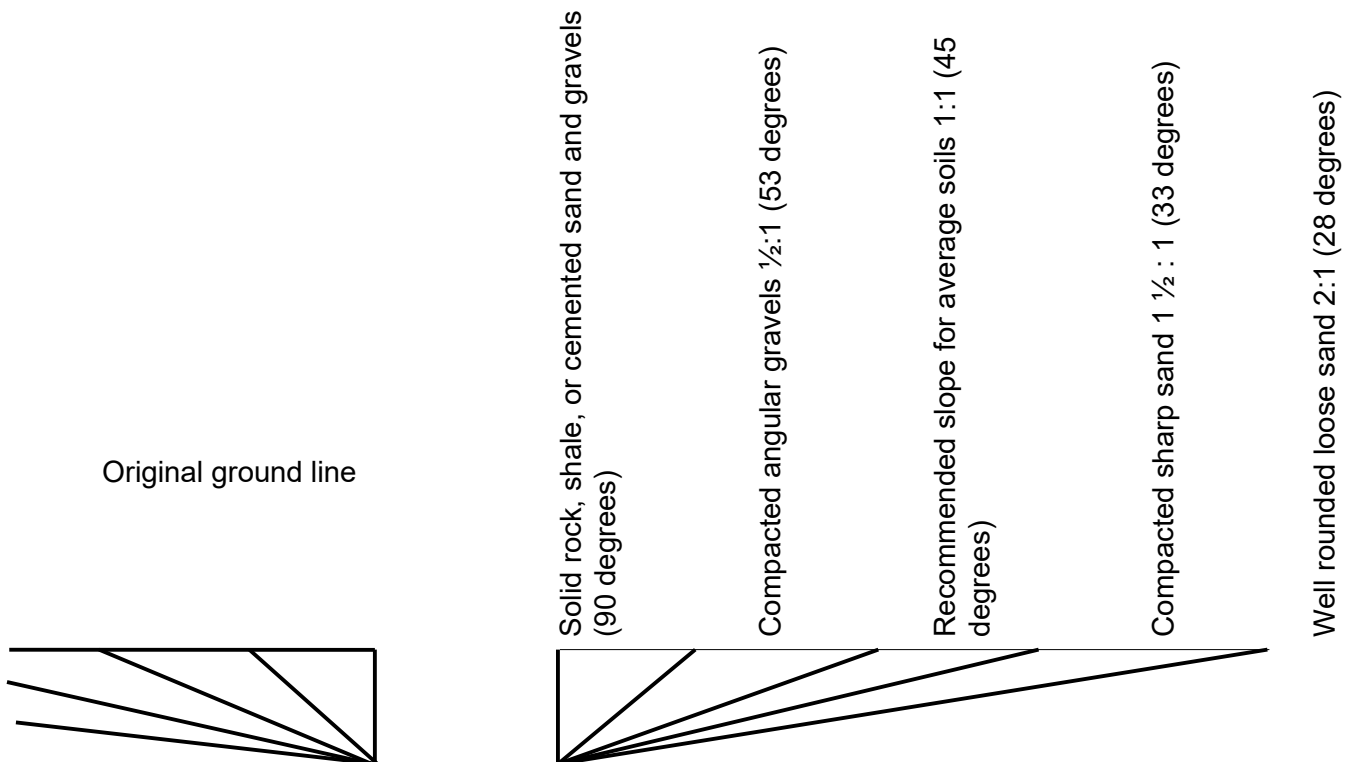
Sides of trenches will be shored or otherwise supported. In lieu of shoring, the sides of the trench above the 4-foot level may be sloped to preclude collapse, but will not be any steeper than a 1-foot rise per each ½ foot horizontal.
 - c) Shoring Materials - Materials used for sheeting and sheet piling, bracing, shoring, and underpinning should be in good serviceable condition. Timbers used will be sound and free from large or loose knots and will be designed and installed to be effective to the bottom of the excavation.



10. Clear the surface of the slope of boulders, stumps, or other hard masses of earth that could roll or slide into the open excavation and endanger personnel below.
11. Keep the slope well packed at all times and at the angles described in the figure on the last page of this procedure.
12. Where hazardous atmospheric conditions exist or may reasonably be expected to develop, emergency rescue equipment, (i.e. breathing apparatus, safety harness and lifeline, basket stretcher, etc.), must be readily available and attended when in use.
13. Employees entering bell-bottom pier holes, or other similar deep and confined footing excavations, must wear a harness with a lifeline securely attached to it. The lifeline must be separate from any other line used to handle material and must be individually attended at all times.
14. If leaving the trench unattended, be sure to properly secure the area. This may be done with barbed wire fences, wooden stockade barriers or steel sheet piles.

Approximate Angle of Repose for Sloping of Sides of Excavations

NOTE: Clays, silts, loams, or non-homogenous soils require shoring and bracing. The presence of ground water requires special treatment.





Description	To determine when an abnormal operation exists and to give operator personnel the appropriate steps to correct the AOC and return the pipeline and/or facility to normal operating conditions.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input type="checkbox"/> Distribution Pipelines
Frequency	As required
Reference	WTG P-191.23 Safety Related Conditions 49 CFR 192.605(c) <i>Procedural Manual for Operations, Maintenance and Emergencies: Abnormal Operation</i>
Forms / Record Retention	<i>District Specific Abnormal Operations Log / 5 years</i> WTG F-192.605(c) / 5 years
Related Specifications	None
OQ Covered Task	None



General Procedures for Abnormal Operations

1. Reports of possible abnormal conditions can come from almost any source, company communication systems, the general public, landowners, vendors, customers, travelers, etc. The employee/company representative receiving such reports should get as much information as possible, such as:
 - a) Nature of the possible issue/incident.
 - b) Location of the possible issue/incident.
 - c) Name and contact information of the person reporting.
 - d) Details of the possible issue/incident.
2. An abnormal operation is:
 - a) Any operation that exceeds the pipeline's design limits. Note: the definition of design limits is any operation parameter outside of "normal" operating conditions (which may result in hazard to persons or property).
 - b) Unintended valve closures or station shutdowns
 - c) Loss of communications unless normal operating conditions can be verified by other means. Activation of any safety device
 - d) Malfunction of a component (which may result in hazard to persons or property).
 - e) Personnel error related to pipeline activities (which may result in hazard to persons or property)
3. The company employee should take immediate steps to identify the cause of the possible abnormal operation and take appropriate corrective action. Ensuring personal safety and public safety is the priority when taking corrective actions.
4. Once the cause of abnormal operation has been identified and corrected, the appropriate field personnel should monitor the pipeline to ensure it has returned to normal operating conditions. All critical operational points must be reviewed and any variation from normal operation must be accounted for.
5. The responding company employee will communicate with the District Manager and report the abnormal operations, the root cause, and methods of correction.
6. Following an abnormal operation, the District Manager is responsible for the following actions for each AOC within their district:
 - a) Review the event and ensure the root cause was identified.
 - b) Enter the event in the District Specific Abnormal Operations Log.
 - c) Review the response to ensure employee actions were effective.
 - d) Ensure the event did not contain a safety-related condition (See P-191.23).



- e) In addition, the procedures used during the abnormal operations will be periodically reviewed for effectiveness.
- f) In the event information/lessons learned by other WTG district employees can be obtained by sharing the specifics of the AOC, the District Manager will complete Form F-192.605(c) and forward it to the Compliance Department.
- g) Retain documentation in the DOT files.



Description	To establish the process for verification and documentation of material properties and attributes of onshore steel transmission pipelines.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input type="checkbox"/> Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.607	<i>Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission pipelines</i>
	49 CFR 192.619	<i>Maximum Allowable Operating Pressure: Steel or Plastic Pipelines</i>
	49 CFR 192.620	<i>Alternative maximum allowable operating pressure for certain steel pipelines</i>
	49 CFR 192.624	<i>Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.</i>
	LA Title 43 Part XIII 2719	<i>Maximum Allowable Operating Pressure: Steel or Plastic Pipelines</i>
Forms / Record Retention		
Related Specifications	ASME/ANSI B31.8-2003 <i>Gas Transmission and Distribution Piping Systems</i>	
OQ Covered Task	None	



Procedure Steps

Steel Transmission Pipeline Segments

1. Documentation of material properties and attributes for each pipeline segment must be maintained for the life of the system. The records must be Traceable, Verifiable, and Complete (TVC). These records include physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.). If Charpy v-notch toughness values established under this section are used, they are required to meet the requirements of the ECA method at §192.624(c)(3) or the fracture mechanics requirements at §192.712 must be maintained for the life of the pipeline.
2. If the documentation of material properties and attributes for each pipeline system are not Traceable, Verifiable, and Complete (TVC), the following process must be completed. A conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:
 - a) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.
 - b) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.
 - c) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
 - d) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.
 - e) Verification of material properties and attributes for non-line pipe components must comply with paragraph (5) of this section.
3. Procedures developed in accordance with paragraph (2) of this section for verification of material properties and attributes using nondestructive methods must:
 - a) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;
 - b) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and



- c) Use test equipment that has been properly calibrated for comparable test materials prior to usage.
- 4. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:
 - a) WTG must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: **Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates**. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.
 - b) In addition to the requirements in paragraph (4)(a) of this section, the WTG must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to §192.614, until completion of the lesser of the following:
 - i) One excavation per mile rounded up to the nearest whole number; or
 - ii) 150 excavations if the population is more than 150 miles.
 - c) Prior tests conducted for a single excavation according to the requirements of paragraph (3) of this section may be counted as one sample under the sampling requirements of this paragraph (4).
 - d) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the WTG must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve **at least a 95% confidence level** that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. WTG must notify PHMSA in advance of using an expanded sampling approach in accordance with §192.18.
 - e) WTG may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (4)(b) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. WTG must notify PHMSA in advance of using an alternative sampling approach in accordance with §192.18.



5. For mainline pipeline components other than line pipe, WTG must develop and implement procedures in accordance with paragraph (3) of this section for establishing and documenting the ANSI rating or pressure rating
 - a) WTG is not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.
 - b) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
 - i) Larger than 2 inches in nominal outside diameter,
 - ii) Material grades of 42,000 psi (Grade X-42) or greater, or
 - iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
 - c) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. WTG must document the method used to determine the pressure rating and the findings of that determination.
6. The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi.



Description	To describe the process for providing continuing surveillance on the pipelines. This will include surveillance following extreme weather events and natural disasters.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (<input type="checkbox"/> <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Ongoing	
Reference	49 CFR 192.613	<i>Continuing Surveillance</i>
Forms / Record Retention	F-192.613/Life of Pipeline	
Related Specifications	Emergency Operations Plan(EOP)	
OQ Covered Task	None	



Procedure Steps

Responsibilities for continuing surveillance are distributed throughout the company. Each work order has a designated person or position that is responsible for completing that task.

It is the overall responsibility of the District Manager to review work orders or any forms completed during routine maintenance of the line along with any safety related condition reports, incident reports, emergency actions, pipeline integrity reports and any other relevant data.

Special attention should be paid to changes in class location, failures, leakage surveys, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

Information from these reviews is used to determine the overall integrity of the pipeline and any trends that could lead to pipeline failures.

If a segment of pipe is determined to be in unsatisfactory condition, but without immediate hazards existing, the operator will develop and initiate a program to recondition or phase out the segment involved, or if this is not possible, reduce the maximum operating pressure in accordance with 49 CFR 192.619(a) and (b).

If the District Manager determines a segment of pipeline is unsafe, he will take immediate steps to have the segment repaired, replaced, or removed from service.

In the case of an extreme weather event or natural disaster, the EOP is to be activated. As required in the EOP the operator must inspect all potentially affected pipelines to detect any new hazards that may have occurred from the event. The inspection should be made when the operator determines the area can be accessed safely by personnel and equipment. In the event that the inspection cannot be completed within 72 hours, notification must be made to the compliance department. The compliance department will notify the appropriate PHMSA region director as soon as possible.

Following the inspection, the operator must take prompt and appropriate remedial actions to ensure the safe operation of pipeline. Document inspection and any actions taken on F-192.613. Such actions may include

1. Reducing the operating pressure or shutting in pipeline
2. Modifying, repairing or replacing any damaged pipeline facilities
3. Preventing, mitigating or eliminating any unsafe conditions in ROW
4. Performing additional patrols, surveys, tests, or inspections
5. Implementing emergency response activities with Federal, State or local personnel
6. Notifying affected communities of the steps that can be taken to ensure public safety



Description

This procedure describes the requirements for public notice and follow-up in connection with excavation activities around gas pipelines.

NOTE: Texas Intrastate Pipelines: WTG will follow the excavator portions of this procedure when they are performing excavations or have contractors excavating on their behalf. They will follow the operator requirements when others are excavating in the vicinity of WTG pipelines.

**Regulatory
Applicability**

- ☒ Regulated Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☒ Regulated Gathering Pipelines (Type B)
- ☒ Regulated Distribution Pipelines

The following Texas intrastate pipelines are exempt from the requirements of this procedure:

- The exemptions in Texas Utilities Code, §251.003;
 - The movement of earth that does not exceed a depth of 16 inches;
 - Surface mining operations;
 - The following activities when performed by an employee of TxDOT within TxDOT right-of-way:
 - Sampling and repair of pavement, base, and subgrade;
 - Repair of roadway embankment adjacent to pavement structure;
 - Reshaping of unpaved shoulders and drop-offs;
 - installation and maintenance of guardrails, cable barriers, delineators, vehicle attenuators, sign posts, mailboxes, and cables for traffic signals and luminaries;
 - Cleaning of ditches; and
 - Removal of silt from culverts; or
 - Hand digging by an employee or contractor of TxDOT for TxDOT's archeological program.
-

Frequency

Provide notifications to excavators and the public as often as needed to make them aware of the damage prevention program.

Receive and respond to line locate requests on an ongoing basis.

Reporting for Texas Intrastate Pipelines:

- Excavator –
 - When damage is done to an underground pipeline, contact the Operator through the notification center immediately, but no more than 2 hours after the damage and the Commission within 10 days through TDRF.



- If a second notification is required for marking due to no response, notify the Commission through TDRF.
- If an Operator does not provide a positive response to the second notification notify the Commission through TDRF.
- Operator
 - Report to the Commission all damage to pipelines caused by an excavator within 10 days of the damage incident or of the operator's actual knowledge of the damage incident through TDRF.

Reference	49 CFR 192.614 <i>Damage Prevention Program</i>
	LA Title 43 Part XIII <i>Damage Prevention Program</i>
	165 OAC Chapter 20-5-51 <i>Mandatory Participation in Oklahoma One Call</i>
	NM 18.60.5 <i>Pipeline Excavation Damage Prevention</i>
	TAC Title 16, Part 1, Chapter 18, <i>Underground Pipeline Damage Prevention</i>
	Texas Utilities Code, Section 251
	American Public Works Association (APWA) Uniform Color Code (ANSI Standard Z535.1, Safety Color Code)

Forms / Record Retention	F-192.614 <i>Damage Prevention / Life of Pipeline System if our line was crossed; 5 Years if it was not</i>
	F-192.706 <i>Leakage Survey / 5 Years</i>
	Form WTG-1100 <i>Exposed Pipeline Inspection / 5 Years</i>
	Form WTG-1101 <i>Leak Survey Report Form / Life of the Pipeline System</i>
	One-Call Ticket or Excavator Request

Related Specifications	None
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OQ Covered Task	1291 <i>Locate underground Pipelines</i>
	1331 <i>Damage Prevention Inspection During Third Party Excavation or Encroachment Activities as Determined Necessary by Operator</i>
	1341 <i>Provide or Assure Adequate Pipeline Support During Operator Initiated Excavation Activities</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



***WTG's Individual State Specific Damage Prevention Plans are located at
www.westtexasgas.com.***



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Description	This procedure provides guidelines personnel will follow in order to effectively respond to an emergency. Note: This procedure is to be furnished to all supervisory personnel that are responsible for emergency action.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Any time an emergency is suspected	
Reference	49 CFR 192.605(b)(11) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> 49 CFR 192.615 <i>Emergency Plans</i> LA Title 43 Part XIII 2705(b)(11) <i>Procedural Manual for Operations, Maintenance and Emergencies</i> LA Title 43 Part XIII 2715 <i>Emergency Plans</i> 165 OCC Chapter 20-5-14 <i>Telephonic notice of an evacuation of a building</i>	
Forms / Record Retention	F-192.615	<i>Handling Emergencies / 3 Years</i>
	F-191.1	<i>Incident Notification, Reporting & Investigation / Life of the Pipeline System</i>
	F-191.9	<i>Incident Notification, Reporting & Investigation (Distribution) / Life of the Pipeline System</i>
Related Specifications	<i>West Texas Gas Emergency Plan</i>	
OQ Covered Task	None	



*WTG's Company Emergency Plan is located at
www.westtexasgas.com.*



Description	This procedure ensures that emergency responders and public officials for areas affected by pipeline operations are contacted periodically for emergency planning.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Annually, at intervals not to exceed 15 months for each fire, police or other public official in the area that may respond to a pipeline emergency. Texas – Proximity to School - No later than January 15 th of every even-numbered year	
Reference	49 CFR 192.615 <i>Emergency Plans</i> 16 TAC Title Rule 8.235 <i>Natural Gas Pipeline Public Education and Liaison</i> LA Title 43 Part XIII 2715(c) <i>Emergency Plans</i>	
Forms / Record Retention	F-192.615(c)	<i>Public Liaison / 2 years or Until Next Review whichever is Longer</i>
Related Specifications	None	
OQ Covered Task	None	



Procedure Steps

1. Contact appropriate fire, police, and other public officials who might have a role in response to a local pipeline emergency. Pipeline regulating agencies require liaison with groups who would normally be involved in emergency response in connection with pipeline operations. Those groups include local fire and police departments as well as other organizations that undertake emergency response functions.

- a) Fire Departments-Local municipal or volunteer fire departments will typically respond to pipeline emergencies. While their involvement may be limited to fighting secondary fires, they play an important role in the response. Lack of coordination between the pipeline operator and local fire officials may result in a dangerous situation. Similarly, the lack of pipeline emergency experience and knowledge of the pipeline system can present serious dangers for the firefighting team. Therefore, the pipeline operator will identify and contact each fire department along its line that might be called upon to respond to a fire.
- b) Police Departments-Local municipal police or county sheriff departments may also respond to a pipeline emergency. Their function will typically be crowd control and evacuation of persons in the vicinity of the emergency. Police agencies that might respond to emergencies along a pipeline should be identified and contacted. As with fire officials, lack of coordination between the pipeline operator and police organizations can endanger the police and others.
- c) Other Organizations-An investigation of the emergency response plan for an area may reveal that part or all the firefighting or policing functions are handled by local emergency planning committees or Civil Defense agencies. In such a case, the officials of these agencies should be identified and contacted for liaison. Similarly, in some rural areas, the city or county governments may be so small that firefighting or policing functions are handled by elected officials such as mayors, city council members, or county commissioners. If elected officials handle firefighting or policing functions, they will be contacted for liaison.

Liaison will be performed with an official of each fire and police department whose area is traversed by the regulated pipeline. Where firefighting or policing functions are handled by other organizations (such as local emergency planning committees) or where, in less populated areas, these duties are handled by elected officials, they will be contacted.

2. Meeting objectives:

- a) Learn the responsibility and resources of each government organization that may respond to a pipeline emergency. (Document the anticipated response of the officials to a typical emergency and the resources they have available.)
- b) Acquaint the officials with the operator's ability and plans for response to a pipeline emergency. (Explain how we would handle various types of emergencies.)
- c) Identify the types of pipeline emergencies where the operator will notify public officials.
- d) Plan how the operator and public officials can engage in mutual assistance to minimize hazards to life and property. (Note what contacts should be made in an emergency. Also



consider how and when we should coordinate a response with local emergency responders.)

3. Face-to-face meetings are preferred. When local officials are unavailable after repeated attempts to arrange a meeting, it is recommended that attempts at liaison be documented in a letter to the officials. A documentation letter will provide information required by the regulation such as a description of the operator's system and the operator's plans in the event of a pipeline emergency.
4. Where a public official declines a face-to-face meeting, but will discuss, by phone, pipeline safety issues, it is recommended that a confirmation letter be sent discussing the points communicated and areas of cooperation identified in the phone conversation in addition to the operator's capabilities and plans.
5. The documentation of any meeting with public officials should indicate that we provided the officials the following information about our system:
 - a) Location of our regulated lines
 - b) Materials carried in our pipelines
 - c) Normal pressures in the pipelines
 - d) General system design and shutdown procedures
 - e) Emergency plans and resources
6. Document specific emergency contacts for the agency, the resources the agency may have at its disposal, and how the agency might respond to an emergency. Document conclusions reached as to the following:
 - a) Type of events that might be classified as emergencies
 - b) Situations where notice and coordination might be necessary
 - c) Potential joint response appropriate for given emergency scenarios
7. A face-to-face meeting is recommended with each emergency responder who might be called upon to respond to a pipeline emergency. Where an emergency responder declines to meet, a letter is recommended from the operator to demonstrate compliance. Liaison contacts, whether by face-to-face meetings or other means, will be documented on Form F-192.615(c).

Texas Intrastate Pipelines

Designated representative will communicate and conduct liaison activities on an annual basis (at intervals not exceeding 15 months) with fire, police, and other appropriate public emergency response officials according to the provisions in the first part of this procedure. These activities will be conducted as follows:

1. An effort to conduct a community liaison meeting in person with the officials by one of the following methods must be done first:
 - mailing a written request for a meeting in person to the appropriate officials by certified mail, return receipt requested;



- sending a request for a meeting in person to the appropriate officials by facsimile transmission; or
 - making one or more telephone calls or e-mail message transmissions to the appropriate officials to request a meeting in person.
 - If a scheduled meeting does not take place, the operator or operator's representative shall make an effort to re-schedule the community liaison meeting in person with the officials using one of the methods above before proceeding to arrange a conference as described below.
2. If the operator or operator's representative cannot arrange a meeting in person after complying with #1 of this section, the operator or the operator's representative will make an effort to conduct community liaison activities by means of a telephone conference call with the officials by one of the following methods:
- mailing a written request for a telephone conference to the appropriate officials by certified mail, return receipt requested;
 - sending a request for a telephone conference to the appropriate officials by facsimile transmission; or
 - making one or more telephone calls or e-mail message transmissions to the appropriate officials to request a telephone conference.
 - If a scheduled telephone conference call does not take place, the operator or operator's representative shall make an effort to re-schedule the community liaison telephone conference call with the officials using one of the methods above before proceeding to mail the liaison information as described below.
3. If the operator or the operator's representative has made the efforts required by #1 and #2 above but has not successfully arranged and held either a meeting in person or a telephone conference, the community liaison information required to be conveyed will be delivered by mailing the information by certified mail, return receipt requested.
4. In areas where any part of the natural gas pipeline facility is located within 1,000 feet of a public school building or public school recreational area West Texas Gas will notify the Commission by filing with the Safety Division, using the electronic version of the Form PS-87, no later than January 15th of every even-numbered year the following information:
- the name of the school;
 - the street address of the school; and
 - the identification (system name) of the pipeline.
5. Maintain records documenting compliance with the liaison activities. Records of attendance and acknowledgment of receipt by the emergency response officials will be retained for five years from the date of the event that is commemorated by the record. Records of certified mail and/or telephone transmissions will also be retained.



Description	To establish and implement a written continuing education program that follows the guidance provided in the American Petroleum Institute's Recommended Practice 1162. Note that this is a stand alone program and should be referred to for provisions on handling public awareness requirements.
<hr/>	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
<hr/>	
Frequency	As needed per API 1162 Program
<hr/>	
Reference	49 CFR 192.616 <i>Public Education</i> LA Title 43 Part XIII 2716 <i>Public Education</i>
<hr/>	
Forms / Record Retention	None
<hr/>	
Related Specifications	API Recommended Practice 1162 <i>Public Awareness Programs for Pipeline Operator, First Edition (December 2003).</i>
<hr/>	
OQ Covered Task	None



Procedure Steps

Refer to COMPANY's API RP 1162 Public Awareness Program.



Description	To establish the procedure that will be followed to efficiently investigate pipeline incidents and failures.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.617 <i>Investigation of Failures</i>	
Forms / Record Retention	F-191.1	<i>Incident Notification, Transmission Reporting and Investigation Packet / Life of Pipeline System</i>
	F-191.9	<i>Incident Notification, Distribution Reporting and Investigation Packet / Life of Pipeline System</i>
Related Specifications	West Texas Gas Operator Qualification Program	
OQ Covered Task	None	



Procedure Steps

1. For Texas intrastate pipelines, a supervisory review of leak complaints must be completed and documented by 10:00 a.m. each day for calls received by Midnight on the previous day.
2. Secure the site and maintain it as undisturbed as possible.
3. Each accident and/or failure shall be investigated as soon as possible after the incident and that investigation will include interviews of witnesses, if any, to determine the following:
 - a) The cause of the accident or failure
 - b) The method by which it could have been prevented
 - c) What measures should be taken to prevent it from recurring
4. Excavate surrounding areas as needed. If appropriate, samples of the failed facility or equipment should be retained for examination or laboratory analysis. Each must be properly marked or tagged for identification.
5. Arrange for employee interviews.
6. Alcohol test each employee or contractor's employee whose performance may have contributed to the incident in accordance with the DOT Drug and Alcohol Plan. (This must be done within 2 hours of the incident.)
7. Drug test each employee or contractor's employee whose performance may have contributed to the incident in accordance with the DOT Drug and Alcohol Plan. (This must be done within 32 hours of the incident.)
8. Refer to the Operator Qualification Program for information on handling employee's whose performance of a covered task may have contributed to the incident.
9. Conduct on-site investigation using form F-191.1 for Transmission or F-191.9 for Distribution.
10. Arrange consultants to assist in the investigation.
11. Analyze field data, operating history, and lab results.
 - a) Study system pressures.
 - b) Study most recent leak surveys.
 - c) Study most recent patrols.
 - d) Check for construction activity in the area.
 - e) Other data pertinent to this accident/failure.
 - f) Check for extenuating damage along pipeline outside the initial damage zone.
12. Provide a lesson learned that includes but not limited to;
 - a) Operational changes or facility modifications.
 - b) personnel training and qualification programs
 - c) design
 - d) construction



- e) testing
 - f) maintenance and operations
 - g) emergency procedure manual and specifications
 - h) potential preventative and mitigative measures (HCA areas)
 - i) SCADA system performance
 - j) Emergency valves or rupture mitigation valve locations and valve actuation (response time)
 - k) Any additional factors to prevent or minimize future incidents
13. For incidents that include rupture mitigation valves (RMV) or alternative equivalent technology that is part of a Transmission pipeline or Type A gathering; a summary of an incident review must be completed within 90 days of the incident. During the completion of the incident review, quarterly a status review must be completed until the investigation is complete and a final summary is prepared. These documents must be reviewed, dated, and signed by the appropriate senior manager. All data collected, including witness interviews and samples, regarding the accident/failure will be fully documented and kept for as long as the facility in question is in service. For Type B, C, R gathering and distribution, RMV's or alternative equivalent technology are not required thus these investigation requirements are not applicable.
14. If there is third party damage, complete form PS-89 on the TRRC website.



Description	To establish the process for determining the Maximum Allowable Operating Pressure (MAOP) for gas pipeline facilities.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.619	<i>Maximum Allowable Operating Pressure: Steel or Plastic Pipelines</i>
	49 CFR 192.620	<i>Alternative maximum allowable operating pressure for certain steel pipelines</i>
	49 CFR 192.621	<i>Maximum allowable operating pressure: High-pressure distribution systems</i>
	49 CFR 192.623	<i>Maximum and minimum allowable operating pressure; Low-pressure distribution systems</i>
	49 CFR 192.624	<i>Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.</i>
	49 CFR 192.632	<i>Engineering Critical Assessment Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.</i>
Forms / Record Retention	F-192.619	<i>MAOP Determination / Life of Pipeline System</i>
Related Specifications	ASME/ANSI B31.8-2003	<i>Gas Transmission and Distribution Piping Systems</i>
OQ Covered Task	None	



Procedure Steps

Transmission and Gathering

1. Gather the following information to complete form F-192.619 and calculate the maximum allowable operating pressure of the pipeline that commensurate with the class location.
 - a) Class location
 - b) Pipe specification – yield strength, nominal wall thickness, outside diameter
 - c) Gas temperature in pipeline
 - d) Type of longitudinal seams
 - e) Date of pipe manufacture
 - f) Flange pressure rating
 - g) Component pressure ratings
 - h) Pipeline pressure test
2. Use this data to determine which is lower:
 - a) The design pressure of the weakest element
 - b) Test pressure divided by the applicable following factors:

Class location	Factors			
	Installed prior to 11-12-70	Installed after 11- 11-70	Installed on or after 7-1-2020	Converted under 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

For a component whose design pressure is not known, pressure test factor is ≥ 1.3

- c) Highest actual operating pressure to which the pipeline was subjected during the 5 years preceding the applicable date in the second column of the table below. This pressure restriction applies unless the segment was tested according to the requirements of 49 CFR Subpart J after the applicable date in the third column or the segment was uprated according to the requirements in 49 CFR Subpart K.

Pipeline Segment	Pressure Date	Test Date
Onshore gathering line that first became subject to 49 CFR 192 (other than 612) after 4-13-06	March 15, 2006, or date line becomes subject to 49 CFR 192, whichever is later	5 years preceding applicable date in second column
Onshore transmission line that was a gathering line not subject to 49 CFR 192 before 3-15-06	7-1-1976	7-1-1971
All other pipelines	7-1-1970	7-1-1965



- d) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with §192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure
- 3. No segment of the pipeline may be operated at a pressure that exceeds the MAOP as determined in F-192.619.
- 4. Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in §192.624(a) must establish and document the maximum allowable operating pressure in accordance with §192.624.
- 5. Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (1) through (5) of this section as follows:
 - a) Operators of pipelines in operation as of July 1, 2020, must retain any existing records establishing MAOP for the life of the pipeline.
 - b) Operators of pipelines in operation as of July 1, 2020, that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with §192.624, must retain the records reconfirming MAOP for the life of the pipeline; and
 - c) Operators of pipelines placed in operation after July 1, 2020, must make and retain records establishing MAOP for the life of the pipeline.

Note: The requirements of pressure restrictions described in this procedure do not apply if the pipeline is in satisfactory condition, considering its operations and maintenance history, and the highest actual operating pressure of the pipeline during 5 years preceding the applicable date in the second column of the above table. 49 CFR Part 192.611 must still be followed.

In the unlikely event WTG will need to utilize an Alternative Maximum Allowable Operating Pressure, a written process will be developed and all regulations within CFR 192.620 will be followed.

Distribution

1. High-Pressure Distribution

For a segment of a high-pressure distribution system, the MAOP cannot exceed the lowest of the following, as applicable:

- a) The design pressure of the segment's weakest element
- b) 60 psig for a distribution system segment otherwise designated to operate at over 60 psig, unless the segment service lines are equipped with service regulators or other pressure limiting devices in series that meet 49 CFR Part 192.197(c) requirements



- c) The pressure the operator determines to be the maximum safe pressure after considering the segment's history. In conformance with 49 CFR Part 192.195, overpressure protective devices must be installed in a manner that will prevent exceeding the MAOP.

2. Low-Pressure Distribution

For a low-pressure distribution system, the MAOP cannot exceed a pressure high enough to make operating any connected and properly adjusted low pressure gas-burning equipment unsafe.

A low-pressure distribution system may not be operated at a pressure lower than the minimum pressure at which safely and continuously operating any connected and properly adjusted low pressure gas burning equipment can be assured.

Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

1. Applicability.

West Texas Gas will review all appropriate MAOP documentation of onshore steel transmission pipeline segments to ensure records are traceable verifiable and complete (TVC). In situations where records are not TVC, WTG will follow this reconfirmation procedure. For the following segments:

- a) A high consequence area as defined in §192.903; or
- b) A Class 3 or Class 4 location.

- 2. Currently WTG's pipeline segment's MAOP are established in accordance with §192.619(a). Thus, currently §192.619(c) is not applicable to WTG. The list of applicable segments for MAOP reconfirmation can be found on the compliance drive under reconfirmation file. Procedures and completion dates.

For pipelines that MAOP reconfirmation is required one of the following 5 methods must be completed: Method 1 pressure test(including spike test and material verification) Method 2 pressure reduction Method 3 critical engineering assessment (ECA) Method 4 pipe replacement Method 5 pressure reduction for segments with small PIR. Details of the processes can be found below. The following schedule will be utilized. WTG must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

- a) WTG will complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035, or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of §192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.
- b) If operational and environmental constraints limit an operator from meeting the deadlines in §192.624, a petition can be made for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with §192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding



remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

- a) One of the following 5 methods will be utilized to reconfirm MAOP for segments that do not have TVC documentation. Method 1: Pressure test. Perform a pressure and verify material properties records in accordance with §192.607 and the following requirements:
 - i. Pressure test. Perform a pressure test in accordance with subpart J of §192.. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii). Which will include a spike pressure test for segments operating at a stress level greater \neq $>$ 30% SMYS in accordance with §192.506.
 - ii. Material properties records. Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).
 - iii. Material properties verification. If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with §192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with §192.607.
- b) Method 2: Pressure Reduction. Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location).
 - i. Where the pipeline segment has had a class location change in accordance with §192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:
 - a. For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.
 - b. For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.



- ii. Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.
- iii. If WTG elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, PHMSA will be notified in accordance with §192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:
 - a. Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in §192.624(c)(2);
 - b. The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with §192.712.
 - c. Justification that establishing MAOP by another method allowed by this section is impractical.
 - d. Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance §192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and
 - e. Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.
- c) Method 3: Engineering Critical Assessment (ECA). Conduct an ECA in accordance with §192.632.
- d) Method 4: Pipe Replacement. Replace the pipeline segment in accordance with this part.
- e) Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius. Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:
 - i. Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (i.e., the location specific operating pressure at each location).
 - ii. Conduct patrols in accordance with §192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with §192.706 at intervals not to exceed those in the following table 1 to §192.624(c)(5)(ii):



Table 1 to §192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3 1/2 months, but at least four times each calendar year	3 1/2 months, but at least four times each calendar year.
Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

- iii. Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.
- f) Method 6: Alternative Technology. WTG may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with §192.18. The notification must include descriptions of the following details:
 - i. The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated.
 - ii. Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered.
 - iii. Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization.
 - iv. Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength.
 - v. If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph §192.712.
 - vi. Operational monitoring procedures.
 - vii. Methodology and criteria used to justify and establish the MAOP; and
 - viii. Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.
- 3. WTG will retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.



Engineering Critical Assessment

If WTG conducts an MAOP reconfirmation in accordance with “Method 3” in the above section, using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA will comply with §192.632. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance.



Description	To establish guidelines for odorization of gas and testing of the odorant amounts. Each gas company shall continuously odorize gas by the use of a malodorant agent as set forth in this section unless the gas contains a natural malodor or is odorized prior to delivery by a supplier.
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**Regulatory
Applicability**

- ☒ Regulated Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☒ Regulated Gathering Pipelines (Type B)
- ☒ Distribution Pipelines

State of Texas:

- Unless otherwise required by 49 CFR Part 192.625(B) or by TAC Rule 8.215, odorization is not required for:
 - gas in underground or other storage;
 - gas used or sold primarily for use in natural gasoline extraction plants, recycling plants, chemical plants, carbon black plants, industrial plants, or irrigation pumps; or
 - gas used in lease and field operation or development or in re-pressuring wells.
 - Gas shall be odorized by the user if:
 - the gas is delivered for use primarily in one of the activities or facilities listed above and is also used in one of those activities for space heating, refrigeration, water heating, cooking, and other domestic uses; or
 - the gas is used for furnishing heat or air conditioning for office or living quarters.
 - In the case of lease users, the supplier shall ensure that the gas will be odorized before being used by the consumer.
-

Frequency

Continually odorize the gas and test levels.

- Record as frequently as necessary to maintain adequate odorization; but not less than once each quarter, record malodorant information for all odorization equipment.
 - Perform sniff test annually
-



Reference	49 CFR 192.625	<i>Odorization of Gas</i>
	TAC Rule 8.215	<i>Odorization of Gas</i>
	LA Title 43 Part XIII 2725	<i>Odorization of Gas</i>

Forms / Record Retention	WTG 1301	Odorant Usage Report / 5 Years
	WTG 1302	Farm Tap Odorant Inspection & Maintenance / 5 Years
	WTG 1303	Odorant Concentration Test / 5 Years

Related Specifications	None	
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OQ Covered Task	1211	<i>Odorization – Periodic Sampling</i>
	1221	<i>Odorization – Odorizer Inspection, Testing, Preventive and Corrective Maintenance</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

The following steps are applicable to both distribution lines and odorized transmission lines, and are to ensure both are odorized to a concentration in air of 1/5 of the lower explosive limit of the gas and are readily detectable by a person with a normal sense of smell:

If WTG odorizes the gas:

1. At intervals not exceeding once each quarter WTG will conduct an Odorant usage injection report, and record on WTG Form F-1301, which includes the following information:
 - a. Odorizer location
 - b. Brand name and model of odorizer
 - c. Name of malodorant, concentrate, or dilute
 - d. Quantity of malodorant at beginning of each reporting period
 - e. Amount added during reporting period
 - f. Quantity at end of reporting period
 - g. MMcf of gas odorized during month/quarter; and
 - h. Injection rate per MMcf
2. At intervals not exceeding 15 months, but at least once each calendar year, WTG will conduct Odorant concentration tests, and record on WTG Form F-1303, which include the following information:
 - a. Odorizer name and location
 - b. Malodorant concentration meter make, model, and serial number
 - c. Date test performed, test time, odorizer tested, and distance from odorizer
 - d. Test results indicating percent in gas in air when malodorant is readily detectable
 - e. Signature of person performing the test

NOTE: The Odorant concentration test shall be conducted at the furthest most point of WTG's system, downstream from the odorization equipment, which is representative of the gas within that system.



Transmission – Class 3 or 4

1. This is not required if:

- At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
- The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;
 - An underground storage field;
 - A gas processing plant;
 - A gas dehydration plant; or
 - An industrial plant using gas in a process where the presence of an odorant:
 - Makes the end product unfit for the purpose for which it is intended;
 - Reduces the activity of a catalyst; or
 - Reduces the percentage completion of a chemical reaction;
- 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
- The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.



Odorant Requirements

Ensure the odorant is commercially available and complies with the following in the concentration that is it used:

1. The odorant may not be harmful to persons, materials, or pipe.
2. The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.
3. Is not soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

Is introduced to the pipeline system, to ensure the level of odorant concentration is consistent with the requirements listed on page 1 of this section.

Texas Intrastate Pipelines

Equipment Requirements:

The odorization equipment meets the following standards:

1. Must be commercially available in any installation made on or after February 4, 2009. Shop-made or other odorization equipment previously approved by the Commission and in use as of February 4, 2009, may continue to be used in its current service, but may not be re-installed in a different location.
2. Maintain a list of odorization equipment used, including the location of the odorization equipment, the brand name, model number, and the date last serviced. The list shall be available for review during safety evaluations by the TRRC Division.

Farm Tap Odorizer tests and reports.

As stated above, WTG will ensure all Farm Tap odorizers contain a natural odorant or are odorized to a concentration in air of 1/5 of the lower explosive limit of the gas by following the steps listed below:

1. Check, test, and service farm tap odorizers at intervals not exceeding 15 months, but at least once each calendar year.
2. At intervals not exceeding 15 months, but at least once each calendar year, WTG will conduct Odorant concentration tests, and record on WTG Form F-1303, which include the following information:
 - a. Odorizer name and location
 - b. Malodorant concentration meter make, model, and serial number
 - c. Date test performed, test time, odorizer tested, and distance from odorizer
 - d. Test results indicating percent in gas in air when malodorant is readily detectable
 - e. Signature of person performing the test



If WTG does not odorize the gas:

In regards to both Transmission and Distribution pipelines, if WTG obtains gas which malodorant previously has been injected WTG does not odorize the gas; WTG will conduct quarterly malodorant concentration tests and retain records for a period of five years.



Description	This procedure provides guidelines to use when performing taps on pressurized pipelines.		
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines		
Frequency	As needed		
Reference	49 CFR 192.627 <i>Tapping Pipelines Under Pressure</i> LA Title 43 Part XIII 2727 <i>Tapping Pipeline Under Pressure</i>		
Forms / Record Retention	NDT Reports, OQ Records, and Project related documents for the Life of the Pipeline System		
Related Specifications	API RP 2201 <i>Safe Hot Tapping Practices in the Petroleum & Petrochemical Industries</i>		
OQ Covered Task	1081	<i>Tapping a Pipeline (Tap Diameter 2 Inch and Less)</i>	
	1091	<i>Tapping a Pipeline (Tap Diameter Greater Than 2 Inch)</i>	
	1101	<i>Tapping a Pipeline With a Built-In Cutter</i>	
	1111	<i>Tapping Cast and Ductile Iron Pipe, and Low Pressure Steel</i>	

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Prerequisites

1. Determine and have engineering review the exact procedure and equipment that will be used for the hot tap.
2. Project Manager, prior to installing the tap assembly, should ensure that appropriate pipeline pressures and flow rates are established for safe welding, tapping operations.
3. Equipment
 - a) The hot tap branch connection shall comply with DOT Part 192. The installed piping base metal thickness and auxiliary support must provide support for the new connection and the hot tapping machine. The hot tap connection shall be designed for the pressure and grade of the pipe being tapped.
 - b) The hot tap fitting must be designed to match or exceed the line's MAOP. Acceptable area of replacement calculation is required for all taps equal to and greater than 2 inches and must be included in the project file. The fitting sleeve shall have a carbon equivalent (CE) of less than 0.45 based upon the manufacturers design.
 - c) Fittings must be supported to remove any induced moment caused by the piping system according to the manufacturers' recommendation.
 - d) Seals and materials of construction must be compatible with the contents in the piping.
 - e) Hot tapping machine must be able to retain and remove the blank or coupon.
4. Location
 - a) Before choosing the hot tap location, the Project Manager shall assess the site to determine its suitability, including but not limited to depth of cover, access and environmental considerations and subsurface water removal requirements, as well as above and below ground obstructions. Once a potential site is determined, calculate to insure that the existing pipeline design and proposed fitting have adequate metal area available for reinforcement in conformance to ASME B31.8, Appendix F.
 - b) The tapping operation produces steel cuttings that fall directly into the pipeline. The possibility of damaging or impairing downstream equipment operation should be considered.
 - c) Install the hot tap fitting in a straight section of pipe. Do not install the hot tap fitting on another fitting. Do not install the hot tap fitting over a circumferential pipeline weld or the weld heat affected zone. Maintain a minimum distance of 1.5 times the nominal pipe diameter or 36 inches, whichever is less, between an end fillet weld on the hot tap fitting and the nearest pipeline girth weld.
 - d) In the area of the proposed hot tap installation, buff the exposed pipe with a wire wheel to bare metal. A hot tap is not allowed on a pipeline if the minimum wall thickness is less than 90% of the nominal specified thickness.
5. Pre-Installation Checklist



Before proceeding with the hot tap, the project manager shall ensure that:

- a) A qualified person must conduct hot tapping or utilize span of control.
- b) The area where the connection is to be made has been identified and physically marked.
- c) The pipe wall thickness has been verified, and any metal imperfections that might prevent a proper weld have been identified and evaluated. An ultrasonic thickness gauge should be used on steel pipe.
- d) A plan has been prepared to monitor and control pressure in the pipeline within the required limits during welding.
- e) All necessary testing for flammable vapors, oxygen and hazardous air contaminants has been conducted using an approved and calibrated CGI to ensure a safe environment.
- f) Potential safety and health hazards have been assessed, personal protective equipment provided and fire retardant clothing used as necessary.
- g) Hot Work Permit has been issued if required.
- h) A fire watch has been established and equipped with a suitable dry chemical fire extinguisher or pressurized fire hose.
- i) Signs and barriers have been provided when warranted.
- j) Procedures have been prepared and are in place to isolate the work area in the event of an emergency.

Hot Tap Operation

1. The Project Supervisor shall conduct a project orientation and safety meeting before work starts. Only qualified personnel shall mount, assemble and operate the hot tapping machines.
2. Perform a dry run before cutting. This dry run includes assuring the vent (bleed valve) is in place. Also, ensure the cutter will clear the hot-tap block valve and the block valve will close.
3. Verify all distance measurements, such as:
 - a) the distance between the retracted pilot drill and the bottom edge of the hot-tap machine adaptor flange face
 - b) the distance between this flange face and the pipeline
 - c) the distance the pilot drill extends beyond the shell cutter
 - d) the shell cutter lowering-in distance (top of pipe where the pilot drill contacts the pipe and the bottom of the coupon formed by the shell cutter)
4. Monitor the hot-tap progress. Monitoring includes:
 - a) watching the travel measurement rod
 - b) noting running time
 - c) noting number of hand cranks
 - d) listening to the drill motor sound



5. Monitor drill motor sound changes: as the cutter starts cutting; when the cutter penetrates the pipe wall; and when it finishes cutting.
6. After completing the tap and before removing the tapping machine, the project supervisor shall ensure that:
 - a) The cutter and pilot bit are fully retracted.
 - b) The hot tap valve is closed.
 - c) The bleeder valve is open and all pressure has been bled off the hot tap machine.
 - d) The hot tap coupon has been retrieved and given to the Company representative for corrosion analysis
7. Repair all damaged coating and coat all added fittings, components and piping in accordance with the Paint, Coatings, and Inhibitors Inspection and Maintenance Manual.

Documentation

Maintain NDT reports, operator qualification records and other project-related documents in the project file for the life of the pipeline.



Description	This procedure establishes the guidelines for purging in order to prevent entrapment of an explosive mixture in new or modified gas pipelines. Also, when purging air from new or modified gas pipelines by using natural gas prior to placing them in service or when purging of natural gas prior to maintenance, testing or abandonment.	
Regulatory Applicability	<input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines	
Frequency	As required	
Reference	49 CFR 192.629	<i>Purging of Pipelines</i>
Forms / Record Retention	None	
Safety and Environmental Precautions	Review all safe and practical methods to reduce the pipeline pressure prior to venting to the atmosphere.	
OQ Covered Task	0301 Manually Opening and Closing Valves 0311 Adjust and Monitor Flow or Pressure Manual Valve Operation 1801 <i>Purging, Abandonment, or Inactivation of Facilities</i>	



Purge Procedure Steps

Note: The following precautions should be taken while conducting this procedure:

Safety precautions should be observed during the purging operations. These precautions should include, but not limited to:

1. Prohibit smoking and open flames in the area
2. Prohibit operation of spark producing equipment such as internal combustion engines, electric motors or switches, etc
3. In the event the facilities being purged are straight forward without multiple laterals or looping systems that includes only one upstream valve or isolation device and one downstream valve or isolation device with an existing blowdown valve, step 4 does not have to be completed.
4. In the event the purging process is for new construction and/or includes multiple laterals or loop lines, a written purge plan must be developed, approved by District Manager and followed during the purge process. Within the written purge plan, careful consideration must be given to the following:
 - a. Completely purging of extremities of all segments/laterals
 - b. Purge process of any piping "loops" within the system which has the potential of air being reintroduced into the main body of the pipeline system.
 - c. When tying in a poly system and there is not a permanent vent valve:
 - i. There must be a safe method to isolate the blowdown process (i.e., temporary manual valve installed or a set of poly squeezers a safe distance from the purge point)
 - ii. Purge point must be located outside of bell hole, be completely vertical and secured to the ground to prevent movement.
5. (If Necessary) Post warning signs and/or barricade area to control public access
6. Purge only thru a vent stack that is at least 6 feet above ground, with secured fittings
7. Each venting areas must be supervised by qualified company employees during purging
8. Provide a fire extinguisher of appropriate type and size at the purging area

Precautions should also be taken to prevent static electrical sparks from igniting escaping gas vapors on plastic pipe.



NOTE: When the pipeline is being purged of air using natural gas, the gas must be released into the pipeline at a moderately rapid and continuous flow. If the gas cannot be supplied in enough quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be placed into the line before the gas. The same is true of air being used to purge gas from the pipeline.

1. Conduct a tailgate meeting prior to purging the pipeline. Discuss the following:
 - a) Blowdown and purging safety and possible hazards
 - b) Location of personnel involved and their duties
 - c) Description, use, and location of each piece of work equipment
 - d) Flow of the purge gas
 - e) Location of firefighting equipment
 - f) Pressure of the gas used to purge the pipeline
 - g) Time required
 - h) Method to check air/gas mixture concentration
 - i) Sequence of valve operations
 - j) Presence of liquids or other special conditions
 - k) Use of personal protective equipment
2. Determine the blow off size, pipeline size, and length of section to be purged
3. Determine the inlet control pressure (see table below)
4. Calculate the purging time period (2 minutes per mile)
5. Before purging is completed, a 100% combustible gas must be achieved and verified with a CGI
6. Install a pressure gauge at the inlet of the section to be purged
7. Have local law enforcement control traffic as necessary
8. Establish communications with all personnel involved in purging of the pipeline
9. Open the blow off valve at the downstream end of the section to be purged
10. Inject inert gas into the inlet end of the pipeline to rapidly displace at least 2 miles of pipe, if necessary in order to prevent a hazardous mixture of gas and air
11. Open the inlet valve far enough to quickly obtain the determined control pressure and maintain this pressure for the necessary purging time
12. At the end of the purging time, close the inlet gas flow valve and continue to vent through the downstream blow off valve for an additional minute per mile of pipe being purged
13. Close the downstream blow off valve



14. Open the inlet valve and slowly bring the pipeline to operating pressure
15. Ensure all valves on the system are open to the proper operating position



Minimum Purge Gas Control Pressure (PSIG) Required for a 2 Minute/Mile Purge Rate

PIPELINE LENGTH (MILE)	2" B/OFF VALVE Inlet Pressure (psig)		4" BLOWOFF VALVE Inlet Pressure (psig)				6" BLOWOFF VALVE Inlet Pressure (psig)					
	4" Pipe	6" Pipe	6" Pipe	8"Pipe	10" Pipe	12" Pipe	12" Pipe	16" Pipe	18" Pipe	20" Pipe	22" Pipe	24" Pipe
1	6	9	3	3	3	5	2	3	4	5	8	12
2	12	13	7	5	5	7	3	4	5	6	8	12
3	18	17	10	7	7	8	5	5	5	7	9	13
4	24	21	13	10	9	10	6	6	6	8	10	14
5	32	25	16	12	11	11	7	7	7	8	11	15
6	40	30	20	14	12	13	9	8	8	9	12	15
7	49	35	24	17	14	14	10	9	9	10	12	16
8	59	41	28	20	16	16	11	10	10	11	13	17
9	71	46	33	22	18	18	13	11	11	12	14	18
10	83	52	38	25	20	19	14	12	12	13	15	19
11	97	59	43	28	22	21	16	13	13	14	16	20
12		66	48	31	25	23	17	14	14	15	17	20
13		73	54	35	27	25	19	15	15	15	17	21
14		81	60	38	29	27	21	16	16	16	18	22
15		90	67	42	32	29	22	18	17	17	19	23
20				63	45	40	31	24	22	22	24	28
25				90	62	52	42	31	28	28	29	33
30					81	66	54	39	35	33	34	38
35						82	68	47	42	40	40	44
40							84	57	50	46	46	50
45								67	58	54	53	56
50								79	67	61	60	63



PIPELINE LENGTH (MILE)	8" BLOWOFF VALVE Inlet Pressure (psig)			10" BLOWOFF VALVE Inlet Pressure (psig)			12" BLOWOFF VALVE Inlet Pressure (psig)			
	20" Pipe	22" Pipe	24" Pipe	24" Pipe	26" Pipe	30" Pipe	34" Pipe	36" Pipe	42" Pipe	48" Pipe
1	2	3	3	2	2	3	2	3	6	10
2	3	3	4	2	3	3	3	3	6	11
3	3	4	5	3	3	4	3	4	6	11
4	4	5	5	3	4	5	4	4	6	11
5	5	5	6	4	4	5	4	4	7	12
6	6	6	6	5	5	5	4	5	7	12
7	7	7	7	5	5	6	5	5	7	12
8	7	7	8	6	6	6	5	6	8	12
9	8	8	8	6	6	7	6	6	8	13
10	9	9	9	7	7	7	6	6	8	13
11	10	9	10	8	7	8	6	7	9	13
12	10	10	10	8	8	8	7	7	9	14
13	11	11	11	9	9	9	7	7	9	14
14	12	12	12	9	9	9	8	8	10	14
15	13	12	12	10	10	10	8	8	10	15
20	17	16	16	13	13	12	10	10	12	16
25	22	20	19	17	16	15	12	12	14	18
30	27	24	23	20	19	17	14	14	15	20
35	32	29	27	24	22	20	17	16	17	22
40	38	34	32	28	26	23	19	18	19	24
45	44	39	36	32	29	26	21	21	21	25
50	51	45	41	37	33	29	24	23	23	27



Notes:

- (1) Purge pressures that exceed 100 psig are not shown in the table. Possible detonation of flammable gases could create unsafe pipeline pressures. Longer purge times (greater than 2 min/mile) and lower purge pressures should be used. See Figure 5-3 for geometry and operating conditions used to calculate the purge pressures in Table 5-1.
- (2) Add 5 psig to the pressures shown in Table 5-1, if purging is done through a crossover arrangement and the pressure is measured at the crossover valve. Example: A 30" pipe, 13 miles long, is to be placed into service. A 10" blowdown is to be used for venting. A fifty percent safety factor is selected. Table 5-1 shows that 30" pipe, 13 miles long, requires a natural gas inlet pressure of 9 psig. The length of time is 13 miles times 2 minutes per mile or 26 minutes. After 26 minutes have elapsed, the venting continues for an additional 13 minutes more. Then the blowoff valve is closed.

Source: AGA Purging Principles and Practice Third Edition 2001



Blowdown Procedure/Safety Precautions

The following Safety precautions should be taken while conducting this blowdown procedure including, but are not limited to:

- 1) Proper PPE
- 2) Prohibit smoking and open flames in area
- 3) Prohibit operation of spark producing equipment such as internal combustion engines, electric motors, or switches, cell phones, or other ignition sources
- 4) (If Necessary) Post warning signs and/or barricade area to prevent public access
- 5) Purge only through a vent stack that is at least 6 feet above ground level with secured fittings
- 6) Each venting area must be supervised by qualified company employees during blowdown.

Precautions should also be taken to prevent static electrical sparks from igniting escaping gas vapors on plastic pipe

Blowdown Procedure Steps

- 1) Conduct tailgate meeting prior to blowing down the pipeline. Discuss the following, but not limited to:
 - a) Blowdown safety and possible hazards
 - b) Location of personnel and their duties
 - c) Description, use, and location of each piece of work equipment
 - d) Where blowdown will occur
 - e) When electrical high lines are an issue, it is recommended that a liquids truck be used with a long enough high pressure hose to safely vent gas away from electrical lines or an anchored directional fitting (non threaded)
 - f) Sequence of valve operations
 - g) Presence of liquids or other special conditions
 - h) Use of proper personal protective equipment
 - i) Continuous monitoring of weather conditions such as (wind direction, thunder storms, etc.) and its effects concerning surrounding facilities for possible ignition sources
 - j) A review of the impact on facilities and customers (including points of receipts, delivery and farm taps) including both upstream and downstream. Affected customers shall be notified prior to work being started
- 2) Install a gauge at various locations to determine complete system blowdown. Ensure gauge is working properly prior to installation



- 3) Secure necessary local permits and have local law enforcement control traffic as necessary
- 4) Establish communications with all personnel involved in blowdown
- 5) Blowdown stack to be at least 6 feet above ground level
- 6) Shut in all affected valves
- 7) Apply WTG's lock-out tag-out procedure
- 8) Eliminate all potential sources of ignition, such as automobiles, cell phones, two-way radios and all other non-intrinsically safe devices
- 9) Begin blowdown using a continuous and moderately rapid flow
- 10) A slug of inert gas may be used to prevent a hazardous mixture of gas and air
- 11) Upon completion of blowdown allow extra time to insure complete depressurization of segment
- 12) Check pressure gauges to insure pipeline is completely blown down. Ensure pressure gauges are working properly
- 13) Use a CGI to determine area safe before introducing an ignition source and continue to check periodically to insure there is no gas build up
- 14) Monitor gas supply and pressure to remaining facilities that are still in-service (upstream and downstream)



Description	The purpose of this procedure to comply with regulations concerning RMV's.	
Regulatory Applicability	<p>Pipelines converted to service regulated by 49 CFR Part 192.</p> <p><input checked="" type="checkbox"/> Regulated Transmission Pipelines</p> <p><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A)</p> <p><input checked="" type="checkbox"/> New or entirely replaced pipelines that meet the follow criteria; greater than or equal to 6" diameter that presides in the following locations: HCA, Class 4, Class 3, and Class 1 or 2 with a PIR greater than 150 feet.</p>	
Frequency	N/A	
Reference	192.3	Definitions
	192.9	What requirements Apply to Gathering Lines?
	192.18	How to Notify PHMSA
	192.179	Transmission Line Valves
	192.610	Change in Class Location
	192.615	Emergency Plan
	192.617	Investigation of Failures and Incidents
	192.634	Transmission Lines: Onshore Valve Shut-off for Rupture Mitigation
	192.635	Notification of potential rupture
	192.636	Response to a Rupture; Capabilities of RMVs or Alternative Equivalent Technologies
	192.745	Valve Maintenance: Transmission Lines
	192.935	What Additional Preventive and Mitigative Measures Must an Operator Take?
Forms / Record Retention		
Related	WTG's Emergency Plan	



Specifications WTG's O&M
 P-192.617
 WTG's TIMP

OQ Covered Task 0331 Visual Inspection and Partial Operation
 0431 Valve Preventative Maintenance
 1341 Provide or Assure Adequate Pipeline Support During Operator
 Initiated Excavation Activities



Definitions

Entirely replaced onshore transmission pipeline segments means, for the purposes of valve spacing found in 192.179 and 192.634, when 2 or more miles of transmission pipeline have been replaced within any 5 continuous miles of pipeline within any 24-month period.

Notification of potential rupture means the notification to, or observation by, the public, emergency notification center or a WTG employee (on-site or SCADA alarms) with indications of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. Rupture identification is when the previous defined release is confirmed. Confirmation can be gained with SCADA or visually.

The following is in addition to the definition of "Notification of Potential Rupture." When an unanticipated or unscheduled change of pressure greater than ~10% occurs and continues to occur within a time interval of 15 minutes or less, SCADA alarms will be sent out automatically to the District Manager or appropriate designee. Some SCADA alarms will be adjusted if documentation in written procedures show operational need for a greater pressure-change threshold due to pipeline flow dynamics that are caused by fluctuations in gas demand, gas receipts, or gas deliveries.

Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that WTG uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. For the purpose of this Definition, PHMSA approved Alternative equivalent technology could be substituted for a RMV in this procedure.

Change in class location

In the event a class location changes on a transmission pipeline or type A gathering occurs after October 5, 2022, the following requirement must be met;

For pipeline replacement that results in 1,000 feet or more of pipeline within the class location within any 24-month period, RMV or alternative equivalent technologies must be installed.



Procedure Steps

WTG will comply with the following procedures to install RMV's when applicable.

RMV's will be installed to completely isolate the applicable segment, which includes upstream supply source, downstream piping, and any laterals or crossover lines. The intent is to completely isolate the gas supply to the ruptured pipeline segment.

Installation Requirements

RMV's must be installed and operational within 14 days of placing the new or replaced pipeline segment into service after March 10, 2023 (check date). If needed, an extension may be requested to PHMSA per CFR 192.18

Shut-off segment valve spacing

RMV's are required not to exceed the following spacing requirements

- (i) 8 miles for any Class 4 location,
- (ii) 15 miles for any Class 3 location, or
- (iii) 20 miles for all other locations.

Laterals

Laterals connected to the ruptured pipeline segment may have RMV's installed at locations other than at the mainline if the contributing gas volumes are less than 5% of the total gas volume. If the above criteria are not met, the RMV must be installed at the mainline.

Laterals that are 12 inches or less may use check valve as an RMV, however the check valve is considered as an alternative equivalent technology and must be approved by PHMSA prior to use.

Crossovers

Manual valves can be used as a RMV for crossover connections, if during normal operations the valve is closed to prevent the flow of gas. An operating procedure must be implemented to document that the valve is closed and locked to prevent the flow of gas. Manual valves are considered as an alternative equivalent technology and must be approved by PHMSA prior to use.



Manual Operation Upon Identification of a Rupture

If a PHMSA approved manual valve is being used and can be operated within 30 minutes at all times, an operating procedure must be implemented that includes consideration of the following.

- a) Response time for designate personnel to ensure valve shut-off
- b) Acquisition of necessary tools and equipment
- c) Driving time under heavy or inclement traffic conditions and at the posted speed limit
- d) Walking time to access the valve
- e) Time to physically shut off all valves manually

Response to a rupture

Valve Shut-off Time

WTG must, as soon as practicable but within 30 minutes of rupture identification, fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.

RMV Valve Operations

WTG will take every action necessary to **protect life first and property second from danger!** In the rare occurrence, by operating the RMV poses a greater safety risk to the public than the venting gas at the ruptured pipeline segment, the RMV can be left open greater than the 30-minute time frame. WTG will develop operating procedures and gain approval from PHMSA prior to taking this action.

Valve Monitoring and Operation Capabilities

During normal operations, abnormal operating, and emergency operating conditions, the SCADA system monitors downstream, pressure, and flow rates. These SCADA points and SCADA computers have the capability to monitor rate of change. In the event a SCADA point fluctuates outside of normal operating parameters, an alarm is sent to district personal. WTG SCADA alarms includes low, critical low, high, and critical high. Any SCADA communication failure results in an alarm and district management is notified. At such time the district management will assign a WTG employee to be within 20 minutes of the RMV to manually operate. Until such time the communication failure is repaired.

Flow modeling



At this time, WTG's infrastructure does not have ASV installed and negates the need for flow modeling simulations of the effected areas. In the event WTG chooses to install any ASV's, this section will be reviewed and revised.

Manual Valves in non-HCA, Class 1 Locations

When using a manual valve for a RMV, WTG must receive PHMSA's approval. When submitting a request to PHMSA the requirements of 192.636(b) must be followed.

RMV maintenance

For valve maintenance see procedure p-192.745 Valve Maintenance.

Additional Preventive & Mitigative Measures

The Installation of RMV will follow Procedure P-192.634. For additional preventive and mitigative measures, see WTG's TIMP plan.

Notification to PHMSA

In the event WTG has the intent to use other technology methods or compliance timeline that differs from regulations, prior notification (90 day minimum) to PHMSA will be made following 192.18. If other technology methods include the use of a manual valve in place of a RMV, the notification to PHMSA must also including the demonstration that installation of a RMV would be economically, technically, or operationally infeasible.

Emergency Plan

WTG's Emergency Plan is a stand-alone plan that can be found by contacting WTG's Compliance Department.

Incident Investigation

For Incident Investigations, See P-192.617



Description To establish a patrol program to observe the surface conditions on and adjacent to the pipeline right-of-way of the pipeline system and to check for leaks.

Regulatory Applicability

- ☒ Regulated Transmission Pipelines
- ☒ Regulated Gathering Pipelines (Type A)
- ☐ Regulated Gathering Pipelines (Type B)
- ☒ Regulated Distribution Pipelines

Frequency **Gas Transmission Lines: Patrols**
The frequency of patrols are determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not exceed:

Class Location	At highway & railroad crossings	At all other places
1 & 2	Twice each calendar year with intervals not exceeding 7 ½ months	Once each calendar year with intervals not exceeding 15 months
3	Four times each calendar year with intervals not exceeding 4 ½ months	Twice each calendar year with intervals not exceeding 7½ months
4	Four times each calendar year with intervals not exceeding 4 ½ months	Four times each calendar year at intervals not exceeding 4½ months



Frequency
(Cont'd)

Gas Distribution Lines: Patrols

The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled-

(1) In business districts, at intervals not exceeding 4 ½ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7 ½ months, but at least twice each calendar year.

Reference

49 CFR 192.703 *General*
49 CFR 192.705 *Transmission Lines: Patrolling*
49 CFR 192.721 *Distribution Systems: Patrolling*

**Forms / Record
Retention**

WTG 1103 *Pipeline Patrol / 5 Years*
F-192.709 *Repair Work Order / Life of Pipeline System*

**Related
Specifications**

None

**OQ Covered
Task**

1311 *Inspect Pipeline Surface Conditions – Patrol Right-of-Way or Easement*

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. Determine section of pipeline to be patrolled.
2. Identify and document the starting and ending points of each patrol (i.e. GPS coordinates, physical address and location descriptions, etc.)
3. The pipeline patrol may be walked, driven or flown.
4. The pipeline patrol will include but is not limited to the following:
 - a) Line leaks may be detected by sight, smell or the presence of dead vegetation.
 - b) Unusual construction activities such as clearing, grading, excavating, trenching, auguring, boring, etc.
 - c) Buildings or other permanent structures being erected within 660' of the centerline of the pipeline.
 - d) Road and fence construction.
 - e) Impending encroachment of foreign construction activities that could be detrimental to the integrity of WTG facilities.
 - f) Exposed pipe as a result of soil erosion.
 - g) Damaged facilities or missing line markers.
 - h) ROW conditions.
5. Document all findings on Form WTG 1103. Notify District Manager of any conditions that may require immediate attention.
6. In the event of a significant change to the pipeline or a change in population density in the vicinity of a pipe segment, note this in the comments section of the form and notify the WTG Compliance Department.



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Description This procedure is used to conduct gas leak surveys.

Regulatory Applicability All DOT regulated gas lines that are not odorized.
☒ Regulated Transmission Pipelines
☒ Regulated Gathering Pipelines
☒ Regulated Distribution Pipelines

Frequency Note: in the state of Texas - when leak detection surveys are used to determine areas of active corrosion or re-evaluate unprotected pipelines, the survey frequency must be increased to monitor the corrosion rate and control the condition. The detection equipment used must have sensitivity adequate to detect gas concentration below the lower explosive limit and be suitable for such use.

Gas Transmission Lines

Class Location	Odorized Gas	Non-Odorized Gas
1 & 2	Once each year, not to exceed 15 months	Once each year, not to exceed 15 months
3	Twice each year, not to Exceed 7½ months* for pipeline segments that are not CP protected the frequency requirement is increased to Quarterly	Twice each year, not to Exceed 7½ months*, for pipeline segments that are not CP protected the frequency requirement is increased to Quarterly.
4	Twice each year, not to Exceed 7½ months for pipeline segments that are not CP protected the frequency requirement is increased to Quarterly	Four times each year, not to Exceed 4½ months*

*A leak detector must be used for these surveys.

Leak detection equipment must be used to conduct all leakage surveys on transmission lines in the State of New Mexico.



Gas Distribution Systems (Outside the State of Texas)

Leakage surveys with leak detector equipment:

Town Plant Distribution Systems	Intervals not exceeding 15 months, but at least once per calendar year
Rural Distribution Systems	As necessary, but at intervals not exceeding 5 years (3 years for lines subject to 192.465(e) where electrical surveys for corrosion are impractical).

**Frequency
(Cont'd)**

Gas Distribution Systems (Texas)

Leakage surveys with leak detector equipment:

In business districts	Intervals not exceeding 15 months, but at least once per calendar year
Polyethylene systems or segments within a system outside business districts	Intervals not exceeding 5 years
All other non-business district cathodically protected steel systems or segments within a system	Intervals not exceeding 3 years
All other non-business district systems or segments within a system.	Intervals not exceeding 2 years

As needed to help determine location of potential leaks and when performing repairs on the pipeline.

Reference

49 CFR 192.706 *Transmission Lines: Leakage Surveys*
49 CFR 192.723 *Distribution Systems: Leakage Surveys*
49 CFR 192.935 *What Additional Preventive and Mitigative Measures Must an Operator Take?*
49 CFR 192.9 *What Requirements Apply to Gathering Pipelines?*
16 TAC Rule 8.203 *Supplemental Regulations*



16 TAC Rule 8.206	Risk Based Leak Survey Program
16 TAC Rule 8.207	Leak Grading and Repair
NM 18.60.2.8(B)(2)	<i>Adoption of Portions of the Code of Federal Regulations</i>
NM 18.60,2,12	<i>Classification and Repair of Leaks</i>

**Forms / Record
Retention**

F-192.706	Leakage Survey / 5 Years
F-192.706(a)	Aerial Leakage Survey / 5 Years
WTG 1101	Leak Report Form / Life of Pipeline System

**Related
Specifications**

None

**OQ Covered
Task**

1311	<i>Inspect Pipeline Surface Conditions – Patrol Right – of – Way or Easement</i>
1261	<i>Walking Gas Leakage Survey</i>
1271	<i>Mobile Gas Leakage Survey</i>
1281	<i>Mobile Gas Leakage Survey</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Leakage surveys will be accomplished by using either vegetation surveys or surveys using approved leak detection instrumentation. Approved instrumentation includes but is not limited to Flame Ionization or Laser Optical leak detection equipment either portable or mobile, with enough sensitivity to detect small leaks. The District Manager will ensure that all employees are qualified through WTG's approved Operator Qualification Program prior to conducting leak surveys.

The use of leak survey instrumentation is required for the following:

Transmission:

1. For transmission pipelines, the use of gas detection instrumentation is required when:
 - a) Surveying Class 3 and 4 areas
 - b) Conducting leak surveys at highway and railroad crossings
2. Vegetation surveys may be conducted when performing a leakage survey in Class 1 and Class 2 pipeline locations that are not located at highways and railroad crossings.

Distribution:

Gas detection instrumentation will be used for all distribution leakage surveys.

1. Traverse the pipeline for indication of a leak.
 - a) Visual indications include but are not limited to: dead vegetation, blowing dirt, bubbling water and frost spots.
 - b) In areas where the piping is located under a hard surface or pavement which would deter leaking gas from surfacing, the survey shall include investigation of cracks in the pavement and sidewalk, manholes, valve boxes, and other locations which may provide an opportunity for detecting leaks. If sufficient openings are not available, those available may be supplemented with additional test holes.
 - c) Refer to manufacturer's procedure for operating leak detection instrumentation.
2. Classify leak according to the tables found in 192.706(b). Immediately report Class 1 leaks to District Manager for remediation.
3. In the event of a leak found during a leak survey complete form WTG 1101 using terminology from Appendix A of procedure P-192.706(b): Leak Reporting. Forward this form to appropriate WTG personnel for entering into the Leak Tracking System.
4. Complete Form F 192.706 forward a copy of the form to appropriate WTG personnel to be entered into the Leak Tracking System.
5. Annually the transmission pipeline specialist and distribution pipeline specialist will review LTS entries to determine if any segment is leak prone. These reviews will be documented



on the annual integrity management reports. Additionally, Remedial actions projects will be developed and proposed to senior management by the appropriate specialist as needed.

- a) A leak prone pipeline could be multiple leaks on a segment due to the same leak cause with like pipe specifications (i.e. material, grade, wall thickness, seam type, etc.).

Gathering:

All gathering pipelines will adhere to the above-mentioned requirements for transmission leakage surveys.

Exceptions

Leakage surveys are not required for Type C gathering pipelines with an outside diameter of 16 inches or less if;

1. The pipeline does not fall within a potential impact circle that includes a building designated for human occupancy or another affected site. (When calculating the PIC, please utilize a factor of 0.73 instead of 0.69.)
2. The pipeline segment does not traverse a class location that includes a building designated for human occupancy or another affected site.



Description	This procedure includes the written procedure for handling natural gas leak complaints; grading and repair schedule of leaks, leak management, and reporting of leaks.	
Regulatory Applicability	All DOT regulated gas lines that are not odorized. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Anytime a leak is discovered.	
Reference	16 TAC Rule 8.210(e) 16 TAC Rule 8.2025 16 TAC Rule 8.207 16 TAC Rule 8.210	Leak Reporting Written Procedure for Handling Natural Gas Leak Complaints Leak Grading and Repair Reports
Forms / Record Retention	WTG 1100 WTG 1101 F-TAC 8.205 PS-95	Exposed Pipe Inspection / 5 Years Leak Report Form / Life of Pipeline System Log of Leak Complaints / Life of Pipeline System Semi-Annual Leak Report (Online filing at http://www.rrc.state.tx.us.onlinefilings/rrconline.phb) / Life of Pipeline System
Related Specifications	None	



OQ Covered	1231	<i>Inside Gas Leak Investigation</i>
Task	1241	<i>Outside Gas Leak Investigation</i>



Procedure Steps

Handling Leak Complaints:

Note: WEST TEXAS GAS will promptly respond to all notifications of a gas leak, gas odor or any notification of damage to the facility by excavators or other outside sources.

1. Leak complaints are received through the pipeline 24 hour / 7 days per week emergency number within each district. This number can be found on pipeline markers and in local listings.
2. Once a complaint is received, it is to be recorded, along with the action taken, on F-TAC 8.205 – Leak Complaint Log.
3. Once the complaint is documented, call a trained individual to locate the source of the leak and determine the degree of the hazard.

Note: Have Pipeline Supervisor review all leak complaints on the next business day by 10:00 am for all complaints received by midnight on the previous day. This review is to be documented on F-TAC 8.205 – Leak Complaint Log.

Training Personnel to Investigate Leak Complaints:

1. WTG personnel are trained to follow procedure P-192.706 and this procedure when using gas detectors to determine where the leak is, the grade of the leak and how to respond to the leak. Individuals locating the leak are qualified through the WEST TEXAS GAS Operator Qualification Plan.

Locating the Source of the Leak

1. Get as precise information as possible of potential location from individual taking complaint.
2. Ensure leak detector equipment has been calibrated properly.
3. Determine wind direction on site.
4. Determine possible leak sources upstream of wind from complaint area.
5. Use portable leak detector to find leak source.



Determining the Degree of Hazard Involved with the Leak

Note: If assistance is required when determining the degree of hazard the following chain of command shall be followed:

Name	Position	Contact Information
Local District Manager		
Bart Bean	VP of Operations	(800) 323-6596 office (806)676-7240 mobile
Ray Reed	Director of Integrity Management	(806)358-1321 office (620)271-3793 mobile

Instructions to Provide to Customers / Public after Determining Degree of Hazard

Once the degree of the hazard has been determined provide customers and the general public in the area with the following information:

1. If leak has been determined to exist on the customers piping, WTG shall inform the customer of the nature and location of the leak (if known) which was discovered. WTG will then inform the customer that the customers meter will be locked, blinded, or removed until the leak has been repaired.
2. Give the following safety tips, as appropriate
 - Turn off and abandon any motorized equipment you may be operating.
 - If in a building, ventilate by opening doors and windows if possible, then exit the building immediately.
 - Avoid flames and operating electrical appliances and/or equipment.
 - Do not smoke or light matches.
 - Do not use telephones (even cellular), flashlights or other items that can produce a spark.
3. If leak has been determined to exist on WTG's piping/facilities, WTG will have properly trained individual determine the grade of the leak and the action required. (See *Leak Grading and Repair Schedule*)



Leak Grading and Repair Schedule

The purpose of the leak grading system is to determine the degree or extent of the potential hazard resulting from gas leakage and to prescribe remedial actions. Each operator shall promptly respond to any notification of a gas leak or gas odor or any notification of damage to facilities by excavators or other outside sources.

In the event a leak is found complete form WTG 1101 using terminology from Appendix A of this procedure. Forward this form to appropriate WTG personnel for entering into the Leak Tracking System.

West Texas Gas will ensure that leak grading is made only by those individuals qualified through WTG's recognized Operator Qualification program, and who possess training, experience, and knowledge in the field of leak classification and investigation, including extensive association with actual leakage work. The judgment of these individuals, based upon all pertinent information and a complete leakage investigation at the scene, will form the basis for the leak grade determination. The qualified individual will ensure that their leak detection equipment has been properly calibrated prior to beginning any leakage surveys.

All leaks identified after September 1, 2008 will be repaired according to the tables on the following pages.



Grade	Definition	Action Criteria	Examples
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate action to eliminate the hazard and make repairs.	<p>Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous.</p> <p><i>*The prompt action in some instances may require one or more of the following.</i></p> <ul style="list-style-type: none">• Implementation of company emergency plan (192.615)• Evacuating premises• Blocking of an area• Rerouting traffic• Eliminating sources of ignition• Venting the area• Stopping the flow of gas by closing valves or other means• Notifying police and fire departments	<ul style="list-style-type: none">• Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard• Escaping gas that has ignited• Any indication of gas that has migrated into or under a building, or into a tunnel• Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building• Any reading of 80% LEL, or greater, in a confined space• Any reading of 80% LEL, or greater, in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building• Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property



2	<p>A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.</p>	<p>In determining the repair priority, criteria such as the following should be considered.</p> <ul style="list-style-type: none"> • Amount and migration of gas • Proximity of gas to buildings and subsurface structures • Extent of pavement • Soil type, and soil conditions (such as frost cap, moisture and natural venting) <p>Grade 2 leaks should be re-evaluated at least once every 30 days until cleared or repaired. The frequency of re-evaluation should be determined by the location and magnitude of the leakage condition.</p> <p>Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify repair within the next five days; while, others will require repair within 30 days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair.</p> <p>On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic re-inspection as necessary.</p> <p>Note: All Grade 2 leaks will be repaired within Six Months of detection.</p> <p>Note: Action must be taken ahead of ground freezing or other adverse changes in venting conditions with respect to any leak which, under frozen or other adverse soil conditions, would likely allow gas to migrate to the outside wall of a building.</p>	<p>Leaks requiring action ahead of ground freezing or other adverse changes in venting condition:</p> <ul style="list-style-type: none"> • Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. <p>Examples of Grade 2 Leaks listed below:</p> <ul style="list-style-type: none"> • Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak • Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak • Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard • Any reading between 20% LEL and 80% LEL in a confined space • Any reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak • Any reading of 80% LEL, or greater, in gas associated substructures • Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair
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Grade	Definition	Action Criteria	Examples
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	These leaks should be re-evaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is repaired, regarded, or no longer results in a reading. Leak must be repaired within 36 months of detection.	Leaks Requiring Re-evaluation at Periodic Intervals: <ul style="list-style-type: none">• Any reading of less than 80% LEL in small gas associated substructures• Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building• Any reading of less than 20% LEL in a confined space



Leak Reporting

All leak complaints reported by the public will be documented and reviewed using Form TAC 8.205 and will be retained in the appropriate file.

In the event WTG personnel determines any leak on a WTG (distribution or transmission) asset, WTG personnel will complete form WTG 1101. This information will be entered into the WTG Leak Tracking System by the appropriate personnel.

In addition to reporting a leak, the gas loss report found on form WTG 1101 must be filled out and submitted to the appropriate personnel.

For applicable (distribution, plastic gathering and plastic transmission lines) Texas pipelines, this system will then be used to make the semiannual leak reports on July 15th and January 15th submission to the Commission.

Note: Refer to the Leak Tracking System manual for further information.

Post-Repair Inspection

A leak is considered to be effectively repaired when qualified WTG personnel obtains a gas concentration reading of 0%. For a repaired leak with a gas concentration reading greater than 0% at the time of repair, conduct a post-repair leak inspection within 30 days after the repair to determine whether the leak has been effectively repaired. If the second post-repair inspection shows a gas concentration reading greater than 0%, continue conducting post-repair leak inspections every 30 days until there is a gas concentration reading of 0%. If after six post repair inspections have been performed and a gas concentration reading of greater than 0% has been obtained, then a new leak report will be created with a new leak grade determination.

Post-repair inspections are not required for leak repairs completed by the replacement or insertion of an entire length of pipe or service line, or for the repair of leakage caused by excavator or third-party damage, provided a complete re-evaluation of the leak area after completion of repairs verifies that no further indications of leakage exist.

Remedial measures such as lubrication of valves or tightening of packing nuts on valves which seal leaks are considered to be routine maintenance work and do not require a post-repair inspection.

When a leak is upgraded to a higher grade, the time period for repair is the remaining time based on its original classification or the time allowed for repair under its new grade, whichever is **less**. This requirement does not apply to a leak that, at the time of discovery, was classified at a lower grade pending a further, more complete investigation of the leak hazard area.



PS-95 Semi-Annual Leak Report Reporting

Note: Instructions for filing this report can be found at the end of this procedure.

On July 15th and January 15th of each calendar year, file Form PS-95: *Semi-Annual Leak Report (electronic filing on the RRC website)*. The form submitted on July 15th will include information from the previous January 1st through the previous June 30th. The report submitted on January 15th will include information from the previous July 1st through the previous December 31st. The report will contain the following information:

- List of all leaks identified on the pipeline system;
- List of leaks repaired;
- List of leaks that remain unrepaired (Note: These should be listed by leak grade);
- Leak location;
- Facility type;
- Leak classification;
- Pipe size;
- Pipe type;
- Leak cause; and
- Leak repair method.



Electronic Filing Requirements

The Railroad Commission of Texas (RRC or Commission) has implemented an online system for the filing of pipeline Integrity reports. The web-based system is a part of the RRC Online system. This document describes Electronic Document Interchange (EDI) filing procedures for the PS-95 Leak Report that is a part of the Pipeline Integrity application.

EDI Filing Option:

a) Capability to file PS-95 Leak Reports via EDI.

b) The new system provides a delimited format allowing filers to easily file via EDI. Anyone using spreadsheet software to compile PS-95 data will be able to export the file to a right curly bracket (}) delimited format for EDI submission.

c) Elimination of the Commission's requirement to submit a test file. The Pipeline Integrity application will validate the format of each file submitted. A file not meeting the formatting requirements will be rejected. The filer will be required to correct the formatting error and resubmit the file. Since this check will be performed each time a file is submitted, the necessity to submit and receive a certification of formatting is redundant and therefore eliminated. However, the Commission will provide EDI filers with the capability to test a file prior to submitting to validate their EDI file format.

d) For specific records not meeting the filing requirements, the filer will receive error/approval feedback on the screen in the form of a message. A file may be resubmitted once all errors are corrected.

Security:

An organization (i.e., a Form P-5 operator) must file a Security Administrator Designation (SAD) Form with the Commission as a requirement for filing online and/or EDI. An account is created for the person designated on the SAD Form as the Security Administrator for the organization. This Security Administrator, in turn, can assign "Filing Rights" to employees of the organization authorizing them to file RRC forms online.

Organizations that have existing SAD forms do not need to re-file. The existing Security Administrators will be able to assign Pipeline Integrity "Filing Rights" to the users within the RRC Online Application.



EDI File and Format Requirements:

1. Permission to file electronically must be obtained from the Commission via a SAD (Security Administrator Designation) Form. Contact the P-5 department for more information. Information may also be found at <http://www.rrc.state.tx.us/formpr/index.html>.
2. The file will have a delimited format. Only the following delimiter is allowed: a right curly bracket} (rcb).
3. Numeric columns must not contain any commas – e.g., use 1000000 for one million, not 1,000,000. Nor should columns contain currency formatting like “\$” or “USD”.
4. Data Entry is case sensitive.

Record Layouts:

Each file submitted to the RRC for EDI Processing must have an Identifying Record as the first record in the file. The processing of this record includes the validation that the User ID is authorized to file electronically. An operator may obtain authorization by submitting the Security Administrator Designation Form (SAD) to the Commission’s P-5 department.

Order	Required	Max Length (in characters)	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of record for this identifying record must be 1.
2	Y	4	Report Type	Alpha-numeric	Must be PS95.
3	Y	10	User ID	Alpha-numeric	User ID assigned by the RRC to the filer. User ID must match User ID of person logged in.
4	Y	32	User Name	Alpha-numeric	Name of the User submitting the file.
5	Y	32	User E-mail Address	Character	Email address for the User. Will be used to contact the USER and should be valid.
6	Y	6	Operator Number	Integer	Operator Number is the 6 digit number assigned to P-5 Operators by the RRC.
7	Y	4	Report Year	Integer	Reporting year currently being. Format is YYYY
8	Y	1	Report Period	Integer	1 = 1 st half of year, January – June 2 = 2 nd half of year, July - December
9	Y	4	Record Count	Integer	Number of records in this filing.

PS-95 Unrepaired Leak Summary Record:

Data Included in this record type will replace any previously submitted data.



Order	Required	Max Length (in characters)	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of Record for Detail Record must be 2
2	Y	6	Total Grade 1 Unrepaired Leaks for filing period	Integer	Number of unrepaired leaks considered an existing or probable hazard to person or property requiring prompt action. See Leak Classification Lookup Table on page 8 for complete grade 1 definition.
3	Y	6	Total Grade 2 Unrepaired Leak for filing period	Integer	Number of unrepaired leaks considered an existing or probable hazard to person or property requiring prompt action. See Leak Classification Lookup Table on page 8 for complete grade 2 definition.
4	Y	6	Total Grade 3 Unrepaired Leaks for filing	Integer	Number of unrepaired leaks considered an existing or probable hazard to person or property requiring prompt action. See Leak Classification Lookup Table on page 8 for complete grade 3 definition.

PS-95 Unrepaired Leak Summary Record:

Data Included in this record type will replace any previously submitted data.

Order	Required	Max Length (in characters)	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of Record for Detail Record must be 3
2	Y	6	Pipeline System ID	Integer	System ID is the 6-digit number assigned by the RRC.
3	Y	20	Operators Leak ID	Alpha- numeric	An Operator-generated number for the leak incident. Must be unique to the incident during that filing period for the Operator. All Characters are allowed
4	Y	8	Date Leak Reported	Integer	Date that the leak was reported, not always the date it occurred including two digit month and day, and 4-digit year. Must be in format (YYYYMMDD). If the specific day is not known, use the first of the month. Date must be prior to or within the current filing period. It may not be a future date.



Order	Required	Max Length (in characters)	Data Item	Data Type	Description
5	Y	40	Street Address 1	Alpha- numeric	Address where the leak occurred. Address may read "2500 Block of Main Street" if the exact address is not know. Must be at least 3 characters in length.
6	N	40	Street Address 2	Alpha- numeric	Second Address Line where the leak occurred.
7	Y	40	City	Alpha- numeric	City (or nearest city) where the leak occurred. Must be at least 3 characters in length.
8	N	5	Zip Code	Integer	5-digit zip code where the leak occurred. If entered, should correspond with the City indicted above.
9	Y	3	Country	Integer	County where the leak occurred. Select an FIPS County Code from County Code Lookup Table beginning on Page 13.
10	Y	1	Leak Located	Integer	Valid values are 1 (above ground piping) and 2 (below ground Piping). The soil/air interface is considered above ground
11	Y	2	Leak Located On	Integer	Further pinpoints the location of the leak along the pipeline. Select a value from Located on Lookup Table on page 8.
12	N	7	Material Type	String	Compression Coupling Material Type – either "Steel" or "Plastic". Required if Leak Located on value equals 12.
13	N	8	Compression Coupling Date	Integer	Date compression coupling installed. Required if leak located on equals 12. Must be format (YYYYMMDD).
14	Y	1	Facility Type	Integer	Indicates the type of Facility affected. Select a code from the Facility Type Lookup Table on Page 8.
15	Y	4	Pipe Size	Decimal	Decimal representation of IPS pipe size from ½ inch to 12 inches. For example, ½ inch would be .5 or 0.5 or 0.50, 3 ½ would be 3.5 or 3.50, and 11 would be either 11 or 11.0, or 11.00.
16	Y	2	Pipe Type	Integer	Material type where the leak is located. Select a code from Pipe type Lookup table on page 9.
17	*	3	Pipe Manufacturer	Alpha- numeric	If the pipe Type Code is 8, 9, or 11, provide a Manufacturer. Select a code from the Pipe Manufacturer Lookup Table on page 9.



Order	Required	Max Length (in characters)	Data Item	Data Type	Description
18	*	3	Pipe ASTM Material Code	Alpha- numeric	If the pie code is 8, 9, or 11, provide the ASTM Material Code. See ASTM Code Lookup Table on page 10.
19	Y	1	Leak Classification	Integer	The leak classification is based on the operating and maintenance procedures. Select a code from the Leak Classification Lookup Table on page 8.
20	*	2	Type of Leaking Joint	Integer	Type of joint that leaked. Required if Located On Code is 5 (joint). Select from a code from Joint Type Lookup Table on page 11.
21	*	2	Type of Leaking Fitting	Integer	The type of fitting that leaked. Required if Located on code is 4 (fitting). Select from Fitting Type Lookup Table on page 11.
22	*	20	Coupling Model	Alpha	The model of the coupling that failed. Required if Located on code is 12.
23	*	20	Coupling Manufacturer	Alpha	The manufacturer of the coupling that failed. Required if Located on code is 12.
24	Y	2	Leak Cause	Integer	The root cause of the failure. Select a code from Leak Cause Lookup Table on page 12.
25	*	250	Other Leak Cause	Alpha- numeric	Further defines an Other Leak Cause. Required if Other Leak Cause code 81 was entered for leak cause. Must be at least 3 characters in length.
26	Y	2	Leak Repair Method	Integer	Type of repair that was made. Select a code from Leak Repair Method Lookup table on page 13.
27	Y	8	Repair Date	Integer	Date the repair was made. The date must be during the reporting period, cannot be a future date, cannot be before the date the leak was reported, and must be formatted YYYYMMDD.



Appendix A:

Lookup Tables:

Leak Classification Lookup Table

Leak Classification Code	Description
1	Grade 1 – an existing or probable hazard to persons or property and requires the operator to take action immediately to eliminate the hazard and make repairs.
2	Grade 2 – is non-hazardous at the time of detection, but requires the operator to schedule repair based on probable future hazard. It can be scheduled for repair on a normal routine basis with periodic re-inspection as necessary.
3	Grade 3 – is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Located on Lookup Table

Located On Code	Description
1	Valve
2	Body of Pipe
3	Stopcock
4	Fitting
5	Joint
6	Gauge Line
7	Riser
8	Regulator
9	Meter
10	Drip
11	Tap
12	Compression Coupling

Facility Type Lookup

Facility Type Code	Description
1	Main
2	Service
3	Transmission



Pipe Type Lookup Table

Pipe Type Code	Description
1	Bare Steel
2	Coated Steel
3	Ductile Iron
4	Cast Iron
5	Galvanized
6	Copper
7	Brass
8	High Density Polyethylene
9	Medium Density Polyethylene
10	Aldyl Polyethylene
11	Poly-Vinyl-Chloride

Pipe Manufacturer Lookup Table (High Density PE, Medium Density PE Or PVC)

Code	Manufacturer
PP1	PolyPipe
PP2	PolyPipe, Inc.
PP3	CSR PolyPipe
RK1	Rinker
PF1	Performance Pipe
PX1	Plexco
DC1	Driscopipe
QU1	Quail
UP1	Uponorr
NP1	Nipak
OTH	Other, not listed, or unknown



ASTM Code Lookup Table

Material Code	Description
PA1	Polyamide PA 32312
PB1	Polybutylene PB 2110
PE1	Polyethylene PE 2306
PE2	Polyethylene PE 2406
PE3	Polyethylene PE 3406
PE4	Polyethylene PE 3408
PV1	Polyvinyl Chloride PVC 1120
PV2	Polyvinyl Chloride PVC 1220
PV3	Polyvinyl Chloride PVC 2110
PV4	Polyvinyl Chloride PVC 2116
ABS	Acrylonitrile Butadiene Styrene ABS 1210
CA1	Cellulose Acetate Butyrate CAB MH08
CA2	Cellulose Acetate Butyrate CAB S004
RTR	Reinforced Epoxy Resin RTRP
OTH	Other Material Designation

Joint Type Lookup Table

Joint Type Code	Description
1	Factory Butt Weld (Steel)
2	Factory Fillet Weld (Steel)
3	Field Butt Weld (Steel)
4	Field Fillet Weld (Steel)
5	Threaded
6	Mechanical joint
7	Bell & Spigot
8	Flange
9	Butt Fusion (Plastic)
10	Socket Fusion (Plastic)
11	Saddle Fusion (Plastic)
12	Electrofusion (Plastic)
13	Sidewall Fusion (Plastic)
14	Not Applicable
15	Other



Fitting Type Lookup Table

Fitting Type Code	Description
1	Mechanical Service Tee
2	Heat Fusion Service Tee
3	Electrofusion Service Tee
4	Welded Service Tee
5	Saddle Fitting
6	Service Tee Cap
7	Anodeless Meter Riser
8	Threadolets/Weldlets/Sockolets
9	Plugs/Caps
10	Elbow
11	Nipple
12	Tee
13	Diaphragm
14	Other Meter Riser
17	Transition Fitting
18	Split Sleeve
19	Leak Clamp
20	Bell Joint
21	Meter Swivel
22	Union
23	Insulator
24	Other

Leak Cause Lookup Table

Leak Cause Group	Leak Cause Code	Leak Cause Description
Corrosion Group		
	11	Corrosion
Excavation Group		
	21	Operator Personnel/Contractors Excavating
	22	Other Third Party Excavators
	23	Locator
	24	Vehicle (Auto/Truck/etc.)
Natural Forces		
	31	Lightning
	32	Washout
	33	Ground Movement
	34	Ice
	35	Static Electricity
Other Outside Forces		
	41	Vandalism



Leak Cause Group	Leak Cause Code	Leak Cause Description
	42	Fire/Explosion First
	43	Excessive Strain
Materials & Welds		
	51	Dent
	52	Gouge
	53	Factory Defect
	54	Wrinkle Bend
	55	Weld (Steel)
	56	Fusion Defect (Plastic)
Equipment		
	61	Equipment Malfunction
	62	Gasket/O-Ring
	63	Packing
Operations		
	71	Inadequate/Failure to Follow Procedures
	72	Stripped Threads
	73	Backfill
Other Group		
	81	Other
	82	Not Excavated

Leak Repair Lookup Table

Repair Method Code	Description
1	Clamp Installed
2	Split Sleeve
3	Encapsulation
4	Component Replaced
5	Abandoned (Not Replaced)
6	Pipe Replaced
7	Greasing
8	Doped/Caulked
9	Tighten
10	Sealing Bell & Spigot Joint
11	Insertion



Description	This procedure describes the steps to ensure that pipelines are marked as required.	
Applies to	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.707	<i>Line markers for Mains and Transmission Lines</i>
	LA Title 43 Part XIII 2907	<i>Line markers for Mains and Transmission Lines</i>
Forms / Record Retention	None	
Related Specifications	None	
OQ Covered Task	1301	<i>Install and Maintain Pipeline Markers</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

1. Identify pipeline to be located.
2. Interpret the company maps associated with the pipeline.
3. Calibrate all locating equipment to be used.
4. Locate the line.
5. Determine proper marker location and orientation of sign per 49 CFR 192.707.
 - a) Consideration should be given to the placement of markers where pipelines cross in close proximity or have probable excavation potential, such as:
 - i) Flood prone drainage areas.
 - ii) Irrigation ditches and canals.
 - iii) Drainage ditches along roadways.
 - iv) Agricultural areas
 - v) Active drilling or mining areas.
 - b) Install signs along each section of a Main or Transmission line that is located in an area accessible to the public.
 - c) Install sufficient number of markers to accurately depict pipe location.
 - d) Place line markers as close as practical to the pipeline.
 - e) Ensure there are markers at each public road crossing and railroad crossing.
6. Safely and securely install the post (support for sign).
7. Attach proper sign for the location.
8. Inspect the signs for correct information, visibility, and replace if missing or damaged.
 - a) The following must be written on a background of contrasting color in letters that are at least 1" high and with a ¼" stroke:
 - i) "Warning," "Caution," or "Danger"
 - ii) "Gas (or the name of the gas transported) Pipeline"
 - b) The appropriate operating company name
 - c) 24-hr. emergency telephone number to report emergency conditions. If possible, the marker should also display the telephone number of the appropriate one-call system and/or 811.



Description	To define defects in steel pipeline and specify the acceptable method for their disposal.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.309	<i>Repair of Steel Pipe</i>
	49 CFR 192.703	<i>General</i>
	49 CFR 192.711	<i>Transmission Lines: General Requirements for Repair Procedures</i>
	49 CFR 192.713	<i>Transmission Lines: Permanent Field Repair of Imperfections and Damages</i>
	49 CFR 192.715	<i>Transmission Lines: Permanent Field Repair of Welds</i>
	49 CFR 192.717	<i>Transmission Lines: Permanent Field Repair of Leaks</i>
	49 CFR 192.719	<i>Transmission Lines: Testing of Repairs</i>
Forms / Record Retention	F-192.619	<i>MAOP Determination / Life of Pipeline System</i>
	F-192.709	<i>Repair Work Order / Life of Pipeline System</i>
	Form WTG-1100	<i>Exposed Pipeline Inspection / 5 Years</i>
Related Specifications	API Spec. 5L	<i>Specification for Line Pipe</i>
	API Spec. 5L1	<i>RP for Railroad Transportation of Pipe</i>
	API Spec. 6D	<i>Pipeline Valves</i>
	ASTM A53/A53M-04a	<i>Standard Specification for Pipe Steel, Black and Hot-Dipped, Zinc Coated, Welded and Seamless</i>



ASTM A106/A106M-04b	<i>Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service</i>
ASTM A333/A372M	<i>Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels</i>
ASTM A381	<i>Standard Specification for Metal-Arc Welded Steel Pipe for Use with High Pressure Transmission Systems</i>
ASTM A671	<i>Standard Specification for Electric Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures</i>
ASTM A672	<i>Standard Specification for Electric Fusion-Welded Steel Pipe for High Pressure Service and Moderate Temperatures</i>
ASTM A691	<i>Standard Specification for Carbon and Alloy Steel Pipe, Electric Fusion-Welded for High Pressure Service with High Temperatures</i>
ASTM D2513	<i>Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings</i>
ASTM D2517	<i>Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings</i>
ASME B16.1	<i>Cast Iron Pipe Flanges and Flanged Fittings</i>
ASME B16.5	<i>Flanges and Flanged Fittings</i>
ASME Boiler Pressure and Vessel Code, Section VIII, Division 1	<i>Rules for Construction of Pressure Vessels</i>
ASME Boiler and Pressure Vessel Code, Section VIII, Division 2	<i>Rules for Construction, Pressure Vessel Alternative Rules</i>



OQ Covered Task	1041	<i>Install Mechanical Clamps and Sleeves – Bolted</i>
	1051	<i>Fit-Up of Weld Type Repair Sleeve</i>
	1061	<i>Install Composite Sleeves</i>
	1071	<i>Repair of Steel Pipe by Grinding</i>
	0731	<i>Joining of Pipe – Flange Assembly</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

General

Any segment of pipe that becomes unsafe must be replaced, repaired, or removed from service. The following procedure describes the most effective way to accomplish this promptly and safely. Hazardous leaks must be repaired promptly.

Immediate temporary measures will be taken to protect the public whenever a leak, imperfection, or damage that impairs the serviceability of a segment operating at or above 40% of SMYS; and it is not feasible to make a permanent repair at the time of discovery. Permanent repairs will be made according to the following:

- A. Non – Integrity Management Repairs: Permanent repairs will be made as soon as feasible.
- B. Integrity Management Repairs: When WTG discovers a condition on a pipeline covered under 49 CFR 192 Subpart O - Gas Transmission Pipeline Integrity Management, WTG will remediate the condition as prescribed by §192.933
- C. (d).

WTG may not use any pipe, valve, or fitting for replacement or repairing pipeline facilities unless it is designed and constructed as required by Part 192.

Unless specifically noted as an exception in this procedure, welded patches will not be used as a means of repair.

Pipeline excavations for repair are to follow procedure P-192.319.

All materials used in the repair of the pipeline or components must comply with the requirements of 49 CFR 192 Subpart B.

Pipe and components being used as replacement in a pipeline must be designed in accordance with 49 CFR Subpart C and D respectively.

Accommodation of Internal Inspection Devices

1. Except as provided in paragraphs 2 and 3 below, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced must be designed and constructed to accommodate the passage of internal inspection devices.
2. Paragraph 1 above, does not apply to:
 - a) Manifolds,
 - b) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities,
 - c) Crossovers
 - d) Sizes of pipe for which an instrumented internal inspection device is not commercially available



- e) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations,
 - f) Other piping under 49 CFR 190.9 that the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices
 - g) Gathering pipelines (Type A or B)
3. An operator encountering emergencies, construction time constraints, and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet paragraph 1 above, if the operator determines and documents why an impracticality prohibits compliance with paragraph 10 above. Within 30 days after discovering the emergency or construction problem, the operator must file a petition under 49 CFR 190.9 for approval of the design and construction that does not accommodate the passage of an instrumented internal inspection device, and why it would be impractical. If the petition is denied, within one (1) year after the date of the notice of denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

Preliminary Investigation

- 1. Inspect any exposed pipeline for leaks, impact damage, coating conditions and external corrosion. Refer to procedure P-192.459 for steps on conducting this inspection.
- 2. Visually inspect buried welds whenever the coating has been removed for any reason. Refer to procedure P-192.241 for steps on conducting this inspection.
- 3. Make a preliminary assessment to determine the extent of the damage or defect. In most cases a visual inspection is sufficient. Use X-ray or other forms of inspection that could be considered helpful if conditions warrant. Refer to procedure P-192.243 for steps on conducting non-destructive testing.
- 4. Investigate to determine the cause of any leaks that are found. Hazardous leaks will be repaired promptly.
- 5. Determine if a safety-related condition exists and whether it should be reported (refer to procedure P-191.23).

Repairs While Operating Under Pressure

- 1. The pressure criteria in this procedure are based upon industry experience and mathematical analysis predicting acceptable pipeline pressures. Such experience indicates that a pipeline which has been damaged and does not subsequently fail (rupture) probably will not fail during the course of repair activities if the actual pressure in the pipe is reduced. With this consideration, the greater the pressure reduction, a reduced risk of pipe failure will occur.
- 2. To minimize risk, repair activities should be accomplished at the lowest operating pressure possible.
- 3. Good engineering judgment is needed to determine the appropriate safe pipeline pressure during repairs. Circumstances to consider when determining safe pipeline pressure include



but are not limited to the following: extent of damage to the pipeline, deliverability requirements, class location, etc.

NOTE: The WTG Operations Manager must be consulted and approval obtained when pipeline pressures are above the recommended maximum pressures and left in service.

NRI Trident Seal Leak Repair System

West Texas Gas has determined that the NRI Trident Seal product, when installed according to the manufacturer's specifications, produces an acceptable and permanent leak repair on pipelines with an operating pressure of 60 psi or less. Utilize the following manufacturer-provided procedure for installing the Trident-Seal Repair Kit.

Installation of the Trident-Seal™ Repair Kit

1. Pinpoint origin of leak following your standard operating leak detection procedures (if using leak detection soap wipe clean and remove any remaining soap from pipe surface before beginning repair).
2. Clean and roughen using a wire brush or included sanding cloth to remove excess rust, dirt or loose scale. Remove any oils, greases, soaps, or foreign materials from pipe surface with included solvent cleaning wipe.
3. Blend or knead putty until it is uniform in color with no streaks.
4. Setting time of putty is a Key Point – DO NOT exceed 3 minute working time of putty before applying rubber pressure sealing tape.

Application of Putty –Pinholes

1. Place ½" ball of putty directly over the pinhole.
2. Press firmly in place. Do not use an excessive amount of putty as it may hinder the repair.

Application of Putty - Joints

1. Roll putty into rope long enough to encompass the entire joint.
2. Use just enough putty to make a smooth transition between the pipe and the fitting.
3. Press firmly in place. Do not use an excessive amount of putty as it may hinder the repair.

Before Application of Pressure Sealing Tape

1. Open pressure sealing tape and remove protective paper from adhesive tape attached to rubber tape end. Adhesive portion anchors pressure sealing tape to the pipe so adequate pressure can be applied.

Application of Pressure Sealing Tape- Pinhole

1. Begin wrapping adhesive tape portion adjacent to the putty to anchor pressure sealing tape to pipe.
2. After one wrap with the adhesive tape begin covering the putty.



3. Apply pressure sealing tape with maximum pressure by stretching as it is applied. Apply most of the tape directly over the putty
4. Tape should be applied totally encasing the putty. Apply all of the tape until the end adhesive tape appears.
5. Continue with end adhesive tape until completed. This will hold pressure sealing tape in position until Outer Wrap can be applied.
6. Be sure end adhesive is fully attached to repair.

Application of Pressure Sealing Tape - Joints

1. Start adhesive portion of tape adjacent to putty. Once the pressure sealing tape starts to cover the adhesive tape begin stretching the tape to apply pressure.
2. Continue stretching the tape as it is wrapped to apply pressure and force the putty into the joint.
3. Continue to apply tape with firm pressure over putty and extending somewhat onto elbow or T surface. Use entire roll of tape until end adhesive appears.

Remove paper backing.

1. Firmly press end adhesive tape on to repaired area.
2. Smooth end onto surface to finish and to retain pressure sealant tape in place and retain tape until Outer Wrap is applied.

STOP: After applying Trident-Seal Pressure Sealing Tape test repair by following your standard leak detection procedures to ensure the gas is sealed and contained. Wipe clean after test. DO NOT open Glass Outer Wrap package until you know leak is completely sealed.

Application of Trident-Glass™ Outer Wrap

1. Water is needed to activate Trident-Glass™ Outer Wrap.
2. Put on supplied gloves.
3. Open foil package at notches on side.
4. Submerge in water for ten seconds.
5. Wrap Trident-Glass™ Outer Wrap over the entire repair area ensuring you achieve an 8-layer application over the leak area.

Application of Trident-Glass™ Outer Wrap – Pinholes

1. Begin wrapping the Outer Wrap adjacent to the repair site, extending over the Pressure Sealing Tape. Use firm pressure while wrapping!
2. Twisting the glass wrap as it is applied helps to conform tightly to the pipe surface.
3. Squeeze and mold in direction of the wrap in order to tighten wrap and conform to pipe area.

Application of Outer Wrap – Joints



1. Begin wrapping adjacent to repair applying firm pressure after the first wrap to cinch the glass around the pipe.
2. Continue wrapping in the direction of the repair applying pressure so the wrap conforms to the joint or T area.
3. Twisting the glass outer wrap as it is applied helps it to conform to the repair surface.
4. Squeeze and mold in direction of the wrap in order to tighten wrap and conform to pipe area.

Application of Compression Film

1. Unroll the first few inches of compression film and begin wrapping from end of repair.
2. Apply two layers of compression film to repair area, pulling tightly to mold glass outer wrap and seal the ends of the wrap to the pipe.
3. Poke holes with pin, wire brush or knife-point in the compression film to allow excess water and gases generated by resin curing process to escape through plastic film.
4. The compression film should be removed and discarded after ten minutes cure time.
5. Paint repair before leaving jobsite.

Things to Remember:

- Make sure pipe surface is TOTALLY clean.
- Make sure Putty is mixed above 50°F (10°C).
- Remember there is only a 3 min working time once the putty is mixed. (knead well so no streaks of color remain).
- Rubber tape must be applied within the 3 minute working time of the putty.
- Don't squeeze the putty out of the joint, squeeze it into the joint.
- Always apply maximum tension to the Pressure Tape.
- Apply most of the tape directly over the repair.
- Don't open the Trident-Glass™ Outer Wrap until you are ready to apply (as it will slowly activate once the bag is opened from the moisture in the air).
- Always leak test the repair prior to application of the Glass Outer Wrap.
- Does not adhere to polyethylene piping.
- If corrosion is larger than leak area, NRI recommends reinforcing with NRI Trident -Wrap™ or approved composite rehabilitation system.

Pipe Kits vs. Pipe Diameter

Each kit contains the correct amount of leak sealant, rubber tape, and outer wrap to accommodate indicated pipe diameters



- For up to **1" Diameter Pipe**: Trident-Glass Outer Wrap is 2 inches wide and 5.8 feet long. Appropriate item is TS2580
- For **1.25" to 2" Diameter Pipe**: Trident-Glass Outer Wrap is 3 inches wide and 10.4 feet long. Appropriate item is TS3104
- For **2.5" to 4" Diameter Pipe**: Trident-Glass Outer Wrap is 4 inches wide and 17.3 feet long. Appropriate item is TS4173
- For **4.5" to 6" Diameter Pipe**: Trident-Glass Outer Wrap is 4 inches wide and 33.5 feet long. Appropriate item is TS4335

Permanent Field Repair of Imperfections and Damages

1. Each imperfection or damage that impairs the serviceability of a length of steel pipeline under 40% SMYS must be repaired or removed. If the repair is made by grinding, the remaining wall thickness must be at least equal to either:
 - a) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - b) The nominal wall thickness required for the design pressure of the pipeline.
2. Each of the following dents (depressions that produce a gross disturbance in the curvature of the pipe wall reducing the pipe-wall thickness) must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20% or more of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:
 - a) The dent contains a stress concentrator such as a scratch, gouge, groove or arc burn;
 - b) The dent affects the longitudinal weld or circumferential weld.
 - c) If the pipe is to be operated at a pressure that produces a hoop stress of 40% or more of SMYS. A dent that has a depth (measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe) of:
 - i) More than $\frac{1}{4}$ inch in pipe 12 $\frac{3}{4}$ inches or less in outer diameter; or
 - ii) More than 2% of the nominal pipe diameter in pipe over 12 $\frac{3}{4}$ outer diameter.
3. Arc burns in pipe that produces a hoop stress of 40% or more of SMYS must be repaired according to procedure P-192.245.
4. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40% SMYS must be:
 - a) Removed by cutting out and replacing a cylindrical piece of pipe (See Pipe Replacement section of this procedure); or
 - b) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability to the pipe.



Repair of Welds

1. If it is feasible to take the segment of pipeline out of service, the weld must be repaired per Procedure P-192.245.
2. A weld may be repaired in accordance with repair or removal of defective weld per applicable code and standard while the segment of transmission line is in service if:
 - a) The weld is not leaking;
 - b) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the specified minimum yield strength of the pipe; and
 - c) Grinding of the defective area can be limited so that at least 1/8 inch thickness in the pipe weld remains.
3. A defective weld that cannot be repaired in accordance with above must be repaired by installing a full encirclement welded split sleeve of appropriate design.

Permanent Field Repair of Leaks

1. If feasible, the segment of pipeline must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.
2. If it is not feasible to take the segment of pipeline out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the line is joined by mechanical couplings and operates at less than 40% of SMYS (See Welded Split Sleeve portion of this procedure.)
3. If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp (See Bolt-on-Leak Clamp portion of this procedure).
4. If the leak is due to a corrosion pit and on pipe that operates less than 40% SMYS, fillet weld a steel plate patch with round corners of the same or greater thickness than the pipe, and not more than 1/2 of the diameter of the pipe in size over the pitted area. (See welded patch portion of this procedure).
5. If the leak is on a submerged offshore pipeline or submerged pipeline in an inland navigable waterway, mechanically apply a full encirclement split sleeve of appropriate design. (See Clockspring and Plidco Sections of this procedure).
6. For a repaired leak with a gas concentration reading greater than 0% at the time of repair, conduct a post-repair leak inspection within 30 days after the repair to determine whether the leak has been effectively repaired. If post-repair inspection shows greater than 0% gas concentration, please refer to Post Repair Inspections in P-192.706(b).
7. All repairs performed must be tested and inspected.

Testing of Repairs

1. Testing of replacement pipe:
 - a) The replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.



- b) For lines of 6-inch diameter or larger and that operate at 20% or more of SMYS, the repair will be non-destructively tested in accordance with 192.241(c).
- 2. Inspection and test of welds:
 - a) Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure. Refer to procedure P-192.241.
 - b) Nondestructive testing of weld must be performed by a trained technician. Interpretation of x-rays shall be made by a technician trained to a Level II. Refer to Procedure P-192.243.
 - c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of API Standard 1104 or ASME Section IX.

Repair of Corrosion Condition

- 1. General Corrosion:
 - a) Each segment of pipeline with general corrosion and with a remaining wall thickness less than that required for the maximum operating pressure of the pipeline must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. If corrosion pitting is so closely grouped that it affects the overall strength of the pipe, the pitting is considered general corrosion.
 - b) References for determining the remaining strength of a pipeline are:
 - i) ASME/ANSI B31G (1991), "Manual for Determining the Remaining of Corroded Pipelines."
 - ii) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," December 22, 1989.
- 2. Localized Corrosion Pitting:
 - a) Each segment of pipeline with localized corrosion pitting to a degree where leakage might result must be repaired or removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits. Inspect the interior of the cutout and the ends of the remaining pipe for internal corrosion, record on Form WTG-1100.

Repair Shorted Casing

- 1. Expose casing and excavate workable area around the carrier pipe.
- 2. Remove end seal.
- 3. Take cathodic protection readings before moving anything, both on pipe and casing. Leave Cu-CuSO₄ reference electrode in the same position in coil when taking both readings.



4. Gently lift pipe with nylon or other straps. Retake cathodic protection readings as in step 3 to determine if short connection has been broken.

NOTE: Expect only a 0.1 to 0.2 V DC shift if the connection breaks; it may take several days for polarization to dissipate off the casing and for casing to show an unprotected potential.

5. Before setting pipe back down, clean out any mud and/or water from casing end, if possible. Inspect exposed pipe for pitting damage per P-192.459.

NOTE: This inspection may necessitate the determination of a safety-related condition. A new determination of the MAOP may be required F-192.619.

6. Center the carrier pipe in the bottom of the casing.
7. Install new casing insulator while providing adequate support. If there is adequate access, install two casing insulators, one directly behind the other, to distribute support more evenly.
8. Lower pipe back down. Check need to install any supplemental support on the pipeline outside of the casing, i.e. with sandbags.
9. Install test wires as required.
10. Install new end seal.
11. Backfill supported pipe and casing end in such a manner that new end seal will not be ruptured.
12. Conduct testing to ensure the casing is repaired. If not, excavate other end and repeat this procedure.

Pipe Replacement

1. Shut-in the pipeline and isolate the section to be replaced. Purge of gas.

Note: A stopple may be inserted to isolate the section of pipe. Refer to the following portions of this procedure: Stopples Fitting Preparations, Sealing the Pipeline with a Stopples Plug, and Plugging the Pipeline with the Lock-o-Ring Plug.

2. Post a fire watch.
3. Cut out the cylinder of pipe.
4. Replace the pipe and weld in place using procedure P-192.225.

Welded Split Sleeve

1. Prepare surface by wire buffing or abrasive blasting as required.
2. Fill dents or voids as needed.
3. Obtain the induced AC potential.
4. Ensure proper ultrasonic has been done for weld ends.
5. Refer to Authorization Procedure for direct welding on line.



6. Prepare and fit collars to pipeline using jacks and chains so inside welds are 4" less than desired length of oversleeve when using 4" collars.
7. Post fire watch.
8. Tack weld side seams of collars.
9. Remove jacks and chains from collars.
10. Weld side seams of collars.
11. Prepare and fit bottom and top halves of oversleeve to collars using jacks and chains (desired length of oversleeve is distance between centers of collars).
12. Tack weld side seams of oversleeve.
13. Remove jacks and chains from oversleeve.
14. Weld side seams of oversleeve.
15. Weld oversleeve ends to center of collars.
16. Weld ends of collars to pipeline.

Bolt-on-Leak Clamp

Mechanical leak repair clamps may not be used as permanent repair methods for any plastic pipe. For steel pipe, manufacturer's procedures will be followed. **Install Tight Fitting Sleeve**

1. Prepare surface by wire buffing or abrasive blasting as required.
2. Fill dents or voids as needed.
3. Obtain the induced AC potential.
4. Ensure proper ultrasonic has been done for weld ends.
5. Refer to authorization procedure for direct welding on line.
6. Prepare and fit top and bottom of tight fitting sleeve to pipeline.
 - a) Install backup straps under longitudinal welds.
 - b) Use jacks and chains to achieve a tight fit, and equal welding gaps for the side seam.
7. Post fire watch.
8. Weld first pass on side seams in all accessible areas.
9. Remove jacks and chains.
10. Complete welding side seams to each other.
11. Weld ends to pipeline.

Sandwich Valve Installation

1. Check bolts, faces and sandwich valves.



2. Rig sandwich valve for installation.
 - a) Clean the flange face of the stopple fitting and the bottom face of the sandwich valve.
 - b) Install the proper gasket.
3. Install sandwich valve.
 - a) Mount the sandwich valve on the stopple fitting making sure retainer ring screws are not obstructed.
 - b) Quarter and tighten the stud nuts (refer to flange-tightening procedure).
 - c) Install cat walk.
 - d) Open the sandwich valve with the valve handle, and record the number of turns for later use. On larger sandwich valves, the travel distance of the valve extension rod.
 - e) Check for proper sandwich valve and stopple fitting bore alignment using a straight edge. (If alignment is poor, loosen stud nuts and make the adjustment.)
4. Take measurements.
 - a) Measure and record from the top of the sandwich valve to the top center of the pipeline, including gaskets. (This measurement will be used in both the tapping and stopple plugging operation.)
 - b) Measure and record from the top of the sandwich valve, plus the gaskets, to the top of the retainer ring segments. (This measurement will be used to set the lock-o-ring plug.)

Stopples Fitting Preparation

1. Read chart or blueprint.
2. Refer to Excavation Procedure.
3. Determine proper location of stopple fitting (no closer than 2" from a circumferential weld).
4. Refer to Authorization Procedure for direct welding on line.
5. Operate ultrasonic where fillet welds are to be made.
6. Prepare fitting: Buff or grind paint off bevel, Check and clean stopple fitting flange face.
7. Fit stopple fitting on line (see sleeving procedure).
8. Place the stopple fitting square to and on the center of the pipe.
9. Rotate all retainer ring screws clockwise and counter clockwise to advance and retract the retainer ring segments inside the stopple fitting. (These segments are used to hold the lock-o-ring plug.)
10. Record the exact number of turns required to fully advance the segments, which is the same number of turns used to set the lock-o-ring plug at a later time.
11. Preheat as needed.
12. Weld side seams.



13. Request pressure reduction.
14. Preheat as needed.
15. Post fire watch.
16. Weld ends on stopple fittings.
17. Weld on 2" equalization fittings when ends are welded (minimum of 18" from fitting could also be used for venting behind vapor plugs).
18. Request return to operating pressure.
19. Support stopple fitting.

Sealing the Pipeline with a Stopple Plugging Machine

1. Prepare the stopple plugging machine.
 - a) Unlock bar lock clamps that keep plugging head and control bar from moving during transportation.
 - b) Extend control bar to expose plugging head by moving control valve handle down. **WARNING:** Do not over-extend plugging head housing.
 - c) Clean and inspect all parts of plugging head housing assembly.
2. Apply sealing element.
 - a) Remove nose piece and discard used sealing element.
 - b) Place new sealing element on yoke face aligning bolt holes.
 - c) Position nose piece on new element.
 - d) Tighten bolts gradually on opposite sides until element has expanded evenly and is tight and centered.
 - e) Torque all bolts.
 - f) Grease sealing element liberally.
 - g) Retract plugging head.
 - h) Tighten bar lock clamps.
 - i) Disconnect power units' hydraulic hoses.
3. Take measurements before moving plugging head onto proper position:
 - a) Control bar face to adapter face.
 - b) Top of sandwich valve to top center of pipe.
 - c) Outside diameter of pipe minus one wall thickness. Install stopple plugging machine.
 - d) Place stopple plugging machine on sandwich valve with plugging head facing section to be isolated.
 - e) Quarter and tighten bolts.



- f) Install bleeder valve, equalization valve and high pressure hose.
- g) Open bypass on sandwich valve to fill stopple plugging adapter while purging air through bleeder valve.
- h) Open sandwich valve.
- i) Close bypass valve.
- j) Release bar lock clamps.
- k) Connect power unit hydraulic hoses to stopple plugging machine.
- 4. Insert plug (downstream stopple first).
 - a) Open equalization valves to equalize pressure across plugging head.
 - b) Lower plugging head slowly into position by moving control valve handle down.
 - c) Tighten bar clamps.
 - d) Close equalization valves to divert oil flow.
- 5. Withdraw plugging head (upstream stopple first).
 - a) Open both equalization valves to equalize pressure across the plugging head.
 - b) Unlock bar lock clamps.
 - c) Retract plugging head slowly to zero by moving control valve handle up.
 - d) Lock bar lock clamps.
 - e) Close sandwich valves and equalization lines.
 - f) Bleed pressure through bleeder valve or drain line on sandwich valve.
 - g) Drain stopple plugging machine.
 - h) Disconnect equalization valve, hoses and bleeder valve.
 - i) Remove stopple plugging machine.

Plugging the Pipeline with the Lock-o-Ring Plug

- 1. Install coupon to plug making sure arrows are aligned.
- 2. Install and tighten plug holder to boring bar with retainer rod on tapping machine.
- 3. Inspect: Plug, Ball check, Spring, Teflon seat.
 - a) Ensure plastic protector has been removed from bottom of Lock-o-Ring.
- 4. Assemble components.
 - a) Install rubber O-ring into lower groove of lock O-ring plug. Align and tighten plug to plug holder. Tighten plug into boring bar.
- 5. Take necessary measurements.
- 6. Install tapping machine with plug fully retracted.



7. Equalize pressure.
 - a) Attach 2" equalization line, Equalize pressure only through bypass on sandwich valve. Open 2" equalization line (optional).
8. Advance opposite segments after coupon passes segments.
9. Run plug down to the top of segments.
 - a) Power plug down within 2". Hand crank to top of segments, Backup plug four turns (1/4").
10. Retract opposite segments.
11. Crank down proper number of turns manually to set plug.
12. Install all segments.
13. Crank down until plug stops and backup until plug stops, then one turn down.
14. Release plug from boring bar with measuring rod
15. Back off boring bar 12 turns on tapping machine.
16. Close 2" equalization line.
17. Open 1/4" bleeder valve and reset if pressure does not bleed off.
18. Retract measuring rod to zero.
19. Relieve pressure from tapping machine.
20. Disconnect 2" equalization line.
21. Pull tapping machine.
22. Remove oil in sandwich valve.
23. Remove plug adapter for future use.
24. Close sandwich valve.
25. Plug and remove 2" valve.
26. Install 2" cap with Teflon tape.
27. Remove sandwich valve.
28. Install flextallic gasket and blind flange on stopple fitting and bolt completion blind.



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Description	This procedure addresses the techniques and procedures for analyzing the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	As Needed
Reference	AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805(R-STRENG)) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines,"
Forms / Record Retention	
Related Specifications	None
OQ Covered Task	None

Procedure Steps

1. *Applicability.*

Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

2. *Corrosion metal loss.*

When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see §192.7); R-STRENG (incorporated by reference, see §192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

3. *Cracks and crack-like defects—*

- a) When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).
- b) If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.
 - i. When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.
 - ii. Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).
 - iii. An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.
- c) For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not

documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

- i. Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - ii. A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in §192.607;
 - iii. A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or
 - iv. Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with §192.18.
4. When performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.
- a) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.
 - b) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through §192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:
 - i. An operator must use one of the following for material toughness:
 - Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in §192.607;
 - If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;
 - If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

- Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with §192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.
 - ii. An operator must assume one of the following for material strength:
 - Grade A pipe (30,000 psi), or
 - The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.
 - iii. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with §192.607, the operator must use values upon which the current MAOP is based.
- 5. Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.
- 6. An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:
 - a) The technical approach used for the analysis;
 - b) All data used and analyzed;
 - c) Pipe and weld properties;
 - d) Procedures used;
 - e) Evaluation methodology used;
 - f) Models used;
 - g) Direct in situ examination data;
 - h) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;
 - i) Pressure test data and results;
 - j) In-the-ditch assessments;
 - k) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
 - l) All finite element analysis results;
 - m) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
 - n) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
 - o) Safety factors used for fatigue life and/or predicted failure pressure calculations;
 - p) Reassessment time interval and safety factors;
 - q) The date of the review;
 - r) Confirmation of the results by qualified technical subject matter experts; and
 - s) Approval by responsible operator management personnel.



Description	This procedure establishes minimum requirements for the abandonment of natural gas pipeline facilities.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	As needed
Reference	49 CFR 192.727 <i>Abandonment or Deactivation of Facilities</i> LA Title 43 Part XIII 2927 <i>Abandonment or Deactivation of Facilities</i>
Forms / Record Retention	F-192.727 <i>Facility Abandonment Record / Life of Pipeline System</i>
Related Specifications	NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions"
OQ Covered Task	1801 <i>Purging, Abandonment, or Inactivation of Facilities</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Abandonment

Prepare a step-by-step procedure for each pipeline to be abandoned. These procedures must consider the following:

1. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends.
 - a) When the volume of the pipeline is so small there is no potential hazard (less than 10% LEL), the pipeline need not be purged.
 - b) Filling with inhibited water is preferred if the line has future utility.
 - c) Offshore pipelines abandoned in place must be filled with water or inert materials.
2. Except for service lines, each abandoned pipeline that is not being maintained in accordance with DOT requirements must be disconnected from all input sources, purged with an inert medium and sealed at the ends. Offshore pipelines must be filled with water or inert materials. The pipeline need not be purged when the volume is so small that there is no potential hazard.
3. Whenever service to a customer is discontinued, the operator must comply with one of the following:
 - a) 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 unauthorized people.
 - b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
 - c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.
4. If air is used for purging, operator must ensure that after purging a combustible mixture (less than 10% LEL) is not present.
5. Whenever a vault or valve box cover has been abandoned, WTG will do the following:
 - a) The vault or valve box cover must be removed or secured in a manner so the vault or valve box cover cannot be opened and/or:
 - b) Each abandoned vault or valve box must be filled with a suitable compacted material.
6. Documentation of abandonment using form F-192.727 or equivalent.

Inactivation

An inactivated pipeline is a pipeline that although not currently in use, will be maintained and serviced per 49 CFR Part 192 so the pipeline may be returned to service at a future date. Inactivating a pipeline does not require NPMS submission.

1. Methods to Inactivate Pipeline



- a) Isolate the pipeline segment from all gas sources by closing all valves. If accidentally pressuring up the pipeline will cause a safety problem, physically isolate the pipeline from all gas sources.
- b) Use either natural gas or inert gas in the pipeline to maintain a pressure of 10 to 20 psig to prevent groundwater from entering the pipe. After the pipeline has been inactivated, take a gauge reading to insure that positive pressure exists.
- c) Continue maintaining the pipeline as though it was in service (i.e., continue conducting and documenting all applicable O&M inspections).

2. Returning Inactivate Pipeline to Service

Inactivated pipelines that have been maintained per 49 CFR Part 192 may not be returned to service without Engineering Department review and following the Management of Change (MOC) process.

3. Reactivating Pipeline

Resolve any questions concerning safely operating the previously inactivated pipeline and appurtenances before reconnecting the pipeline to a gas source or installing a weld end cap. Verify that all isolation devices including pipes, valves and fittings are removed and that all pipe, valves, fittings, etc. that were installed during the inactivation process meet the design requirements or are removed before reconnecting the pipeline to a gas source or installing a weld end cap.

4. Discontinuing Customer Service

When discontinuing service to a customer, complete one of the following steps to guarantee the gas is stopped and ensure that gas will not accumulate within a building or residence:

- a) Lock the block valve or provide another means to prevent an unauthorized person from opening the valve
- b) Install a mechanical device that prevents gas flow to the meter or within the service line
- c) Physically disconnect the customer's piping from the gas supply and open pipe end seals

5. Documentation

- a) Maintain operating, inspecting, testing, maintenance and repair records of each inactivated pipeline for the life of the facility.
- b) Maintain records of each pipeline reactivation (e.g., MOC, investigations, test repairs, replacements and alterations, etc.) for the life of the facility.



**P-192.731(a)(b)(c)
Compressor Relief Devices
Remote Control Shutdown Devices
Compressor Station Emergency
Shutdown System**

Description	This procedure was designed to ensure proper inspection and testing of each pressure relieving and remote control shutdown device in a compressor station. Plus establishing a method for completing and documenting a Station Emergency Shutdown Devices (ESDs) are properly maintained and are functioning correctly.	
Regulatory Applicability	Pressure relieving devices (except rupture discs) in a DOT regulated compressor station. <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Once per calendar year, at intervals not to exceed 15 months.	
Reference	49 CFR 192.163 <i>Compressor Stations: Design and Construction</i> 49 CFR 192.167 <i>Compressor Stations: Emergency Shutdown</i> 49 CFR 192.171 <i>Compressor Stations: Additional Safety Equipment</i> 49 CFR 192.173 <i>Compressor Stations: Ventilation</i> 49 CFR 192.615 <i>Emergency Plans</i> 49 CFR 192.731 <i>Compressor Stations: Inspection and Testing of Relief Devices</i>	
Forms / Record Retention	F-192.731 (a) WTG-Attendance Form F-192.731 (c)	Compressor Station Relief Device / 5 Years Attendance Form / 5 Years Compressor Station ESD Test / 5 Years
Related Specifications	None	



**P-192.731(a)(b)(c)
Compressor Relief Devices
Remote Control Shutdown Devices
Compressor Station Emergency
Shutdown System**

OQ Covered Task	0411	<i>Spring – Loaded Pressure Limiting and Relief Device – Inspection, Testing, Preventative and Corrective Maintenance</i>
	0421	<i>Pilot Operated Pressure Limiting and Relief Device – Inspection, Testing, Preventative and Corrective Maintenance</i>
	0431	<i>Pneumatic Loaded Pressure Limiting and Relief Device – Inspection, Testing, Preventative and Corrective Maintenance</i>
	1361	<i>Station Emergency Shutdown System – Inspection, Testing and Corrective Maintenance</i>

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

General

1. All remote control shutdown devices operated and maintained by West Texas Gas, capable of shutting down a compressor station, compressor units, gas fires, or electrical facilities as referenced in DOT regulations 192.167 shall be subjected to the requirements of this procedure.
2. Gas Areas as used in this procedure are areas within a compressor station that contain major gas containment facilities and include the compressor building, adjacent gas headers, and other concentrations of gas piping or other facilities.
3. Gas fires as used in this procedure are the flames in combustion chambers open to the atmosphere on equipment such as air, gas or water heaters, or re-boilers.
4. A remote control shutdown device is a device (e.g. fuel gas valve, engine ignition switch, or motor control center shunt trip) that is intended to react when an Emergency Shutdown station outside a gas area is tripped to deactivate or shutdown a compressor unit or units and/or gas fires and/or electrical facilities.
5. A test of a remote control shutdown device, accomplished during an Emergency Shutdown System test, that satisfies requirements of P-192.605(c), will satisfy the requirements of this procedure provided time interval requirements are met. Inspection and calibration, where applicable, must still be performed per this procedure.
6. If piping or equipment modifications or additions are made to the facilities protected by the Emergency Shutdown (ESD) system such that the complete blow-down test may no longer be valid, then a full-blow down ESD test must be performed upon completion of work.
7. If an Emergency shutdown system has been activated, intentionally or otherwise, within the calendar year and it can be determined that all items functioned as intended, the annual test requirement has been satisfied.

Pressure Relief Valve (PRV) Inspection and Testing

1. Each pressure relieving device in a compressor station must be inspected and tested at intervals not exceeding 15 months but at least once each calendar year and recorded. Inspections and tests will determine that each device:
 - a) is in good mechanical condition, (refer to manufacture recommendations)
 - b) is adequate from the standpoint of capacity and reliability of operation for the intended service,
 - c) is set to function at the correct pressure,



- d) tested and set for correct pressure rating based on original packagers design ratings,
 - e) vent stacks are properly installed.
 - i) Vent stacks are installed to prevent accumulation of moisture.
 - ii) Vent stacks are properly installed to prevent hammering and vented to a safe place.
 - f) Is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation
 - g) Determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure
 - h) If a test is not feasible, review the calculation of the required capacity of the relieving device at each station and compare these required capacities with the rated or experimentally determined relieving capacity device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner that would cause the capacity to be less than required.
 - i) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.
- 2. Any defective or inadequate equipment must be promptly repaired or replaced.
 - 3. Retain records for at least five (5) years.

Remote Control Shutdown Device Testing

- 1. Each remote control shutdown device in a compressor station must be inspected and tested at intervals not exceeding 15 months but at least once each calendar year and recorded. Inspections and tests will determine that each device:
 - a) If an inspection is intended, visually inspect the device for corrosion, moisture, loose connections, or foreign material that might interfere with its operation.
 - b) If a test is intended, isolate items such as dump valves, which, if operated, will cause an unnecessary waste of gas, chemicals, or might cause an unwanted shutdown of equipment.
 - c) Test the device by introducing an input signal or simulate a condition with the use of an inert gas that causes the device to activate, producing an output response that will shut down or isolate equipment or cause operation of valves or equipment. Actual equipment shutdown or activation by the device is not a requirements it the device can be proven to function properly.
 - d) Clean, repair, or replace parts are required.



- e) If calibration is intended, calibrate by adjusting the mechanism to ensure that an output response or operation always corresponds to an input signal or condition within the manufacturer's prescribed operational tolerance.
- 2. Retain records for at least five (5) years. The use of an electronic scheduler will be used to ensure the test and calibration of the system is completed within the time frame set forth.

Compressor Station Emergency Shutdown System Testing

- 1. Maintain the following information on the ESD system:
 - a) Schematics, drawings, and/or pictures identifying major components of the Shutdown system.
 - b) A written description of how the Shutdown system operates.
 - c) A list of the components that require maintenance and the maintenance tasks involved. Include valves, valve operators, sensor heads, controllers, engine panels, process equipment, and other devices that need to be shut down during and ESD/BSD.
- 2. Train appropriate company and contractor personnel so they have a thorough knowledge of how each Emergency Shutdown system operates and to recognize situations and events when they are expected to actuate the system, when conducting work activities within the facility. For contractor personnel, utilize sections 2b through 2(b)(iv), to conduct training and ensure appropriate documentation during the contractor safety orientation process.
 - a) Train new personnel to adequately operate, inspect, and test each Emergency Shutdown system within a reasonable time after they begin work. Retrain all personnel annually.
 - b) Prepare written documentation of the content of the above required training, and include the following items:
 - i. Operation and purpose of the ESD/BSD system
 - ii. Explain the following basic system components using schematics and/or pictures:
 - Gas detector head locations
 - Fire detector head locations
 - ESD/BSD manual activation
 - Controller equipment



- ESD/BSD valve location
 - Critical test monitoring locations
 - Pilot gas regulator station
 - iii. When a manual ESD/BSD should be activated
 - iv. What to expect when the ESD/BSD systems are activated.
 - v. Purging procedures and “return to normal” verification
 - vi. Update ESD manual as changes are made. *Review* ESD manual annually to assure accurate content of schematics, drawings, and components.
3. Test each Emergency Shutdown system at least once each calendar year. Consider at least the following steps for each Emergency shutdown test:
- a) Schedule an outage with management, and DOT if required by location.
 - b) Prior to each test, review previous tests records to ensure all valves functioned as designed
 - c) Notify neighbors and the fire and/or police department, as required by the location Emergency Plan.
 - d) A successful full blow down of systems or subsystems where all applicable components operate properly is required at least once every five (5) years. Determine if a full plant blow-down, partial plant blow-down, or some other lesser method (blind flange blowdowns) is to be used, on a location-by-location basis. For facilities that has 100% spring operated isolation and blowdown valves installed, total blowdown is not required unless a piping modification has occurred.
 - e) Review the written plan for the operation of the Emergency Shutdown system with applicable employees before each test. Include items such as personnel responsibilities, purging methods, and order of equipment restart.
 - f) Place employees at critical points of shutdown to observe and record Emergency Shutdown system performance.
 - g) Actuate the system utilizing a different Emergency shutdown station each year. Consider performing BSD first.
 - h) Observe and record the timing and function of all major components.
 - i) Any malfunctioning components should be repaired and retested. If the same component fails on subsequent tests consider a new, replacement, or is possible, removal of the component..



- j) Purge piping and reset ESD system.
 - k) Return ESD system to automatic.
 - l) Review the system test to determine whether the test criteria were met.
 - m) All unit ESD control systems should be verified and documented as operating properly. If possible, all available units should be running upon the actuation of the ESD test. If a unit is unavailable or it is not feasible to start a unit at the time of the annual test, the ESD components test should be accomplished by starting the unit when it becomes available or by simulation; before it exceeds the 15-month component test time limit.
4. A successful ESD test means that the entire station blew down (or would have in a situation) in the required time, in the correct order, employees could reasonably be expected to escape, and property damage would be minimized. If there is a component failure, but the ESD blows down successfully; then the component may be tested individually after repairs are made. If there is a component failure and the ESD does NOT blow down successfully, then the entire ESD system must be tested after repairs are made. If the initial ESD test was not successful, the next ESD test will be performed in two months. If the two-month test fails, ESD testing will continue to be performed at one-month intervals. Upon completion of a successful test, the original 12-month scheduled testing date and frequency will continue to ensure that the ESD system is tested each calendar year.
5. Retain records for at least five (5) years.
- a) Complete the Emergency Shutdown Test Report for each ESD test and submit to Admin.
 - b) The use of an electronic scheduler will be used to ensure the test and calibration of the system is completed within the time frame set forth to complete the ESD manual review. Retain documentation for 5 years.
 - c) For all training, complete the training attendance form with all requirements



Description	The purpose of this procedure is to ensure proper storage of combustible materials at compressor stations.				
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input type="checkbox"/>				
Frequency	Ongoing				
Reference	49 CFR 192.735	Compressor Stations:	Storage of	Combustible	Materials
	LA Title 43 Part XIII 2935	Compressor Stations:	Storage of	Combustible	Materials
Forms / Record Retention	None				
Related Specifications	NFPA 30	Flammable and Combustible Liquids Code			
OQ Covered Task	None				



Procedure Steps

1. Storage of flammable and combustible material will comply with National Fire Protection Association (NFPA) Standard No. 30.
 - a) Flammable and Combustible Liquids
 - b) Flammable liquids are rated in three hazard classes based on the liquid's flash point and boiling point (see table below). Flash point is the minimum temperature at which a liquid generates vapors in a sufficient concentration to form an ignitable mixture in air.
 - i) A flammable liquid is any liquid with a flash point below 100°F.
 - ii) A combustible liquid is any liquid with a flash point at or above 100°F. Combustible liquids are rated in three classes based on the liquid's flash point.

Category	Class	Flash Point	Boiling Point
Flammable Liquids Examples: gasoline, methanol, condensate	Class IA	Below 73°F	Below 100°F
	Class IB	Below 73°F	At or above 100°F
	Class IC	At or above 73°F and below 100°F	NA
Combustible Liquids Examples: lube oil, kerosene	Class II	At or above 100°F and below 14 °F	NA
	Class IIIA	At or above 140°F and below 200°F	NA
	Class IIIB	At or above 200°F	NA

2. Combustible or flammable material, i.e. oily rags, absorbents, etc. are to be stored outside of the compressor building except for those items necessary for everyday use.
 - a) Portable Containers

When portable containers are used to transport flammable or combustible liquids, use only containers approved for flammable or combustible liquids. An approved container is a metal container with a capacity of 5 gallons or less and equipped with a spring-closing lid and spout cover, a means to relieve internal pressure and flash-arresting screen.
 - b) Drums

Flammable and combustible products transferred from drums into portable containers must be stored inside a diked area with a drip pan under the dispensing nozzle. Use a ground cable when transferring products into another container.



3. All flammable and combustible material that is necessary for everyday use inside the building will be kept in the approved flammable storage cabinet located in the compressor building.
 - a) Storage Cabinets
 - i) Manufactured storage cabinets must be designed and constructed to National Fire Protection Association (NFPA) Standard No. 30, FM, UFC 79 or other approved standard.
 - ii) The maximum volumes of flammable and combustible liquids that can be stored in a single cabinet are:
 - (1) Classes I or II liquids - a maximum of 60 gallons
 - (2) Class III liquids - a maximum of 120 gallons
4. Aboveground Tanks
 - a) An above ground tank must be located outside the building at least 5 ft. from the exterior wall and be protected according to NFPA 30.
 - b) Aboveground liquid storage tanks may be atmospheric tanks, low pressure tanks or pressure vessels.
 - c) Any flammable or combustible liquid storage tank with a capacity greater than 60 gallons must meet the following requirements:
 - i) Separate any two by a minimum of 3 feet measured shell to shell.
 - ii) Provide normal and emergency venting devices or a combination device
 - iii) Protect steel tank support legs over 12 inches high with fire-retardant materials, except for Class IIIB liquids
 - d) Grounding and Bonding
 - i) Ground each aboveground tank by installing a buried zinc anode or copper rod.
 - ii) All tank unloading valves must have an electrical bonding device (i.e., cable, retractable reel) to prevent static sparking during loading and unloading.
 - iii) Dispense Class I liquids only after both the tank and vehicle or both the dispensing and portable containers are electrically interconnected and grounded.
 - e) Venting
 - i) Install venting devices to prevent excessive pressure buildup that might cause the vessel or container to fail. Provide both:
 - (1) Normal venting to handle filling, draining and ambient heat transfers
 - (2) Emergency venting to handle fire exposure on all flammable and combustible liquid storage tanks, including portable tanks
 - f) Secondary Containment



- i) Provide secondary containment for any discharge from areas containing a tank or group of vessels storing flammable or combustible liquids. Contact Engineering for assistance in determining the proper containment and dike size.
- ii) Note: Do not store loose combustible materials or any containers within a tank's diked area. Keep diked areas clean and free of vegetation and liquids, including storm water runoff.



Description	The purpose of this procedure is to ensure proper performance testing of fixed gas detection and alarm systems in compressor station buildings.	
Regulatory Applicability	<div><input checked="" type="checkbox"/> Regulated Transmission Pipelines</div> <div><input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A)</div> <div><input type="checkbox"/> Regulated Gathering Pipelines (Type B)</div> <div><input checked="" type="checkbox"/> Regulated Distribution Pipelines</div> <p>All DOT regulated compressor station buildings unless the building is:</p> <ul style="list-style-type: none">- Constructed so that at least 50 percent of its upright side area is permanently open; or- Located in an unattended field compressor station of 1000 horsepower or less.	
Frequency	As specified by equipment manufacturer (at least annually)	
Reference	49 CFR Section 192.736	<i>Compressor Stations: Gas Detection</i>
	LA Title 43 Part XIII 2926	<i>Compressor Stations: Gas Detection</i>
Forms / Record Retention	F-192.736	Compressor Station Gas Detection / 5 Years
Related Specifications	None	
OQ Covered Task	9679	<i>Gas Detection and Alarm System Maintenance</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

Purpose

This procedure establishes the requirements for the testing of compressor building personnel warning systems. It contributes to the compliance of DOT Regulation 192.736.

General

1. Each compressor will have a high gas alarm as required by engineering standards.
2. The warning alarm will be activated upon the detection of gas inside the compressor building at a level of not more than 25% LEL.
3. The activation of the stations ESD system will be upon the detection of gas inside the compressor building at a level of not more than 45% LEL.
4. Testing of gas sensors and alarms as part of and included in the ESD systems test satisfies the requirements of this procedure.

Procedure

1. The recommended interval for testing those components of the personnel warning system that involve gas detection and personnel alarms is once each calendar year or per manufacturer recommendations. The testing for all components of this system should not exceed 24 months.
2. Test each gas sensor by introducing a simulated condition that causes the sensor to produce an output response that should cause operation of the warning device.
3. Test the system in each compressor building by introducing a simulated condition to a gas sensor that results in operation of the alarm and verify that the appropriate personnel warning devices are functioning properly.
4. Calibrate, repair, or replace (as required) any sensor or alarm that does not operate as intended. Perform this maintenance immediately and retest the system.

Record

1. The use of an electronic scheduler will be used to ensure the test and calibration of the system is completed within the time frame set forth.
2. Document testing and calibration of the system on form F-192.736.
3. Maintain records for five (5) years.



Description	This procedure covers the inspection, testing, and calibration functions performed on a pressure and/or overpressure control device(s) to verify that they are functioning properly, in good operating condition and adequate for the application.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Transmission, Gathering and Distribution System's OPP: Once per calendar year at intervals not to exceed 15 months. Farm Taps: 36 months not to exceed 39 months	
Reference	49 CFR 192.195	<i>Protection Against Accidental Overpressuring</i>
	49 CFR 192.199	<i>Requirements for Design Pressure Relief and Limiting Devices</i>
	49 CFR 192.201	<i>Required Capacity of Pressure Relieving and Limiting Stations</i>
	49 CFR 192.739	<i>Pressure Limiting and Regulating Stations: Inspection and Testing</i>
	49 CFR 192.741	<i>Pressure Limiting and Regulating Stations: Telemetry or Recording Gauges</i>
	49 CFR 192.743	<i>Pressure Limiting and Regulating Stations: Capacity of Relief Devices"</i>
	49 CFR 192.740	<i>Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines</i>
Forms / Record Retention	F-192.743 WTG 1102	<i>Relief Device Capacity Determination Report / 2 Years</i> <i>Regulator Station Inspection Sheet / 2 Years</i>
Related	None	



Specifications

**OQ Covered
Task**

- | | |
|------|--|
| 0381 | <i>Spring Loaded Pressure Regulated Device –
Inspection and Testing, Prevention and Corrective Maintenance</i> |
| 0391 | <i>Pilot Operated Pressure Regulated Device –
Inspection and Testing, Prevention and Corrective Maintenance</i> |
| 0401 | <i>Controller Type Pressure Regulated Device –
Inspection and Testing, Prevention and Corrective Maintenance</i> |
| 0221 | <i>Inspect, test, and Maintain Sensing Devices</i> |

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

Overpressure devices, and equipment (including regulators, slam valves, relief valves, switches, and transmitters) shall be inspected and tests made once per calendar year at intervals not to exceed fifteen (15) months to determine:

1. In good mechanical condition.
2. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.
3. Set to function at the correct pressure.
4. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
5. If the equipment vents, vents must be terminated in an area that will not create a hazard to persons or other equipment and venting of gas shall not be obstructed.

These overpressure protection devices must be set to limit the pressure in the pipeline below the MAOP (refer to procedure P-192.619). However, if the MAOP is not determined according to P-192.619 these devices must operate at the following pressures:

1. In a low-pressure distribution system, the MAOP pressure must prevent the unsafe operation of any connected and properly adjusted gas utilization equipment.
2. In pipelines other than a low-pressure distribution system:
 - a. If the MAOP is 12 psig or more but less than 60 psig, the pressure may not exceed the MAOP plus 6 psig; or
 - b. If the MAOP is less than 12 psig the pressure may not exceed the MAOP plus 50%.

However, if the MAOP is determined according to 49 CFR 192.619(c) and is 60 psi gauge or more, the control or relief pressure limit is as follows:

1. If the MAOP produces a hoop stress greater than 72% of SMYS, then the pressure limit is MAOP plus 4%.
2. If the MAOP produces a hoop stress of unknown percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

For pressure regulating, limiting, and overpressure protection for individual service lines which are directly connected to production, gathering, or transmission pipelines (Farm Taps – small individual services).

1. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:



- a. In good mechanical condition
- b. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.
- c. Set to control or relieve at the correct pressure consistent with the pressure limits of §192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and
- d. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Note: This section does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

Pressure Switches and Transmitters

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

1. Ensure the switch or transmitter is installed properly and protected from dirt, liquids and other conditions that may prevent proper operation.
2. Obtain verification of device set point for switches and range of transmitter prior to performing calibration.
3. Transmitters will be isolated from the system and checked using a certified pressure gauge. (certified to $\pm \frac{1}{2} \%$).
4. Adjust and calibrate pressure transmitter or switch according to device manufacturer's specifications.
5. Determine correct test medium and range to be used for testing.
6. Isolate the pressure switch or transmitter from the process system.
7. Inspect all connections for leakage.
8. Apply test medium pressure and verify device set point or range "as found." Verify pressure transmitters at zero, mid and full-scale calibration points.
9. Trip switch and ensure alarm is activated in the PLC.
10. If a transmitter or switch is inoperable:
 - a. Notify supervisor
 - b. Repair if possible



- c. Replace
- 11. Re-apply test medium for desired set point or range and adjust if necessary, according to device manufacturer's specifications to establish desired set point.
- 12. Document final set point setting(s), "as left."
- 13. NOTES:
 - a. If there is an electrical short, locate the short and attempt to clear it
 - i. Use an approved monitor for testing atmosphere before testing electronic devices because a hazardous atmosphere could cause an explosion if arcing occurs during equipment testing.
 - b. In the event of an electric shock
 - i. Disconnect electrical supply if necessary
 - ii. Call 911 if necessary
 - c. In cases where the transmitter is removed in order to test it should, if possible be tested in the same position as it is in the field.
 - d. A static calibration check is performed.
 - e. Accuracy is acceptable if +/- 1% of full scale.
 - f. Transmitter to be repaired or replaced as required.
- 14. Conditions that require replacement of transmitter or switch include, but not limited to:
 - a. Switch cannot be calibrated
 - b. Operating point is not repeatable
 - c. Setpoint drifts
 - d. Diaphragm has burst or says "fail"
 - e. Transmitter/switch not stable

Relief Valves

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

- 1. Ensure the relief valve is installed properly and protected from dirt, liquids and other conditions that may prevent proper operation.
- 2. Verify location and unique identifier to be inspected.
- 3. Verify the accessibility of the valve.



4. Verify valve documentation is accurate.
5. Verify all settings with a certified pressure gauge or deadweight tester.
6. Isolate the relief valve from the pipeline system.
7. Apply test pressure from a secondary source into the space between the relief device block valve and the inlet of the relief device.
8. Record the pressure at the time of operation of the device.
9. If the device has not relieved at the proper set point, make necessary repairs with a new or rebuilt device.
10. Retest the device after repair or replacement to verify function and set point.
11. After testing, re-pressure the inlet to the device to make sure the device is not leaking.
12. Visually inspect valve for wear and corrosion.
13. Apply security seal to valve as required by procedures.
14. Place the valve back in service.
15. Document results.

Slam Valve

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

1. Ensure the slam valve is installed properly and protected from dirt, liquids and other conditions that may prevent proper operation.
2. Verify location and unique identifier to be inspected.
3. Verify the accessibility of the valve.
4. Verify valve documentation is accurate.
5. Verify all settings with a certified pressure gauge or deadweight tester.
6. Isolate the slam valve from the pipeline system.
7. Record the pressure at the time of operation of the device.
8. If the device has not operated at the proper set point, make necessary repairs with a new or rebuilt device.
9. Retest the device after repair or replacement to verify function and set point.
10. After testing, re-pressure the inlet to the device to make sure the device is not leaking.
11. Visually inspect valve for wear and corrosion.
12. Place the valve back in service.



13. Document results.
14. Verify that this pressure is consistent with 49 CFR Part 192.201(a). (See Verify Relief Device Capacity section of this procedure.)

Pressure Limiting Devices

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

NOTE: Most control type valves operate with a diaphragm or bellows type actuator. A diaphragm type actuator functions because pressure or vacuum is applied to the diaphragm which causes valve position to change.

1. Ensure the pressure limiting device is installed properly and protected from dirt, liquids and other conditions that may prevent proper operation.
2. Verify the proper rupture disc rating. Rupture disk ratings should not exceed MAOP.
3. Obtain verification of device calibration set point prior to performing calibration.

NOTE: Test gauges will be calibrated annually not to exceed 15 months

4. Determine correct test medium and range to be used for testing.
5. Isolate over pressure device from the process system.
6. Inspect all pilots, regulators, rupture discs, sensing devices and control valves for leakage.
 - a. A continual loss of air or hydraulic pressure normally indicates valve or actuator failure. Valve actuators are normally repaired in the shop.
 - b. Manufacturer's repair procedures for one make and model of valve should not be used for other makes and models of valve even if the valves are similar in type.
 - c. The rupture disc lifespan is determined by the manufacturer's specifications.
 - d. Rupture disc failure can be detected by obtaining a pressure reading on the opposing side of disc or lower pressure on the downstream side of the device.
7. Apply test medium pressure and verify device "as found "set point".
8. Document results.
9. Re-apply test medium for desired set point and adjust device in accordance with device manufacturer's specifications to establish desired set point.

WARNING: Do not apply excessive pressure to rupture disc assemblies.

10. Document final set point setting, "as left".
11. Verify that this pressure is consistent with 49 CFR Part 192.201(a). (See Verify Relief Device Capacity section of this procedure.)



Pressure Limiting and Monitor Regulators

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

1. Install an appropriate test gauge on the downstream side of the regulator to monitor the pressure buildup.
2. Properly bypass and isolate the device to be operated.
3. Slowly introduce pressure to the device and at the same time, monitor the pressure gauge to see if the regulator is set at the correct pressure and maintains the correct pressure.
4. The regulator should control the pressure within the buildup limits:

System MAOP

Maximum Protected Pressure

Up to 18" WC

27" WC

18" WC to 12 psig

MAOP + 50%

12 psig to 60 psig

MAOP + 6 psig

Over 60 psig

MAOP + 10%

5. If the device does not control the pressure within the prescribed limits, immediate adjustments, repairs or replacement must be made.
6. The results of each inspection shall be recorded on form WTG 1102.

Verify or Set Protection Parameters

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

1. Obtain verification of device set point or operating parameters to be implemented or changed.
2. Ensure proper isolation of the affected PLC program section from the Process System.
3. Verify data within the current program and document the data "as found".

Implement changes or install new programming section according to PLC manufacturer's specifications.

1. Verify program acceptance through software or dynamic testing methods.
2. Document system alterations "as left".
3. Verify that this pressure is consistent with 49 CFR Part 192.201(a).

Verify Capacity of Regulator and Relief Devices

1. Each pressure relief or limiting station or group of these stations installed to protect the pipeline from overpressure must have enough capacity to insure the following:



- a. In a low-pressure distribution system, the pressure must not cause unsafe operation of any connected gas utilization equipment.
 - b. Pressure relief or limiting devices connected to a low-pressure distribution system must be located at or near the source of gas and with a capacity to limit the maximum pressure on the system to a safe operating pressure for any connected utilization equipment.
 - c. If the MAOP is 60 psi gauge or more, the pressure may not exceed the MAOP plus 10%, or the pressure that produces a hoop stress of 75% of SMYS, whichever is lowest.
 - d. If the MAOP is 12 psi gauge or more, but less than 60 psi gauge, the pressure may not exceed the MAOP plus 6 psi gauge.
 - e. If the MAOP is less than 12 psi gauge, the pressure may not exceed the MAOP plus 50%.
2. Test the devices in place or review and calculate the capacity of the relief devices by a SME. This process must be completed annually and documented (Form F-192.743). to ensure the device has sufficient capacity to protect the pipelines to which they are connected.
 3. If review and calculations are used to determine sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations are not required if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.
 4. If it is determined that the relief device capacity is insufficient, a new or additional device must be installed to provide the required capacity.

Telemetry or Recording Gauges

Note: Refer to manufacturer' procedures for specific equipment requirements and procedures for inspecting and maintenance.

1. If the district is supplied by more than one regulating station, ensure telemetry or recording gauges are in place.
2. The District Manager will determine the need for these devices in distribution systems that are supplied by only one district station. This determination will take into consideration the number of customers supplied, the operating pressures, the capacity of the installation and other operating conditions.
3. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment will be inspected, and the necessary measures employed to correct any unsatisfactory operating conditions.



Description	This procedure gives steps to maintain DOT valves in good working condition.	
Regulatory Applicability	Each transmission line valve that might be required during an emergency <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Once each calendar year at intervals not exceeding 15 months	
Reference	49 CFR 192.745	<i>Valve Maintenance: Transmission Lines</i>
	49 CFR 192.747	<i>Valve Maintenance: Distribution Systems</i>
Forms / Record Retention	WTG 1104	<i>Emergency Valve Inspection / 5 Years</i>
Related Specifications	None	
OQ Covered Task	0331	<i>Visual Inspection and Partial Operation</i>
	0341	<i>Valve Preventative Maintenance</i>
	1381	<i>Operate Gas Pipeline; Local Facility Remote Control Operations</i>
	(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)	



Procedure Steps

Valve maintenance shall be an ongoing activity with major repairs conducted as operation and line scheduling permits. Routine maintenance also shall be performed during the required valve inspection, or more frequently as conditions dictate to ensure valves are in good working order at all times.

1. Coordinate maintenance activities with operations and all affected entities.
2. Verify location of valve to be inspected.
3. Have proper equipment and Traffic plan.
4. Verify the accessibility of the valve. Determine if this is a confined space. Use "Safe Entry Procedure" when entering underground or enclosed vaults.
5. Review safety procedures and Check air quality.
6. Verify the valve number and nameplate data, if applicable.
7. Verify the valve type and manufacturer. (Types of valves include gate valves, butterfly valves, ball valves, check valves, remote controlled valves, etc.)
8. Inspect valve and components.
 - a) Locate valve to be inspected by map or alignment sheet.
 - b) Ensure safe access to valve. Valve may be located within confined space or high traffic area. Appropriate plans and permits should be attached if applicable.
 - c) Verify valve number.
 - d) Check for visible leaks - be sure that inspection includes main body, packing area, plugs, reliefs (if applicable), and flange areas (Employee will visually inspect top, bottom, left and right.)
 - e) Check paint condition.
 - f) Check for operator damage.
 - g) Check the components to ensure they are not bent or broken.
 - h) Check the valve for correct open/close position per facility operations.
 - i) Ensure valve is locked as appropriate, when applicable.
 - j) Check for corrosion. If corrosion is found, initiate further investigation and remediation if necessary.
 - k) Ensure valve is protected from unauthorized operation and vandalism (Rupture mitigation valves in normal operations cannot be locked to prevent unauthorized operations)



9. Operate valve.
 - a) Partial operation (1/4 of a turn) is acceptable if full operation of the valve is not feasible.
 - b) Motor valves should be stroked using the power actuator. For remote control valves, initiate closing remotely
 - c) Ensure position indicators are correct.
 - d) For RMV check valves, ensure the valve operates as designed and does not allow high pressure to backflow.
10. Adjust operator/actuator as necessary per manufacturer's procedure.
 - a) Inspect exterior of operator for any damage.
 - b) Replace operator lubricant, as needed.
 - c) Inspect switch compartment for corrosion.
11. Lubricate valve stem, bearings, etc with appropriate product per manufacturer's procedure.
12. Lubricate valve seat as appropriate.
 - a) Grease valve bearings.
 - b) Spray threads and shaft with a dry lubricant, if applicable.
13. Pack valve stem per manufacturer or industry recommendations.
14. Verify proper tagging and component identification, if applicable.
15. Winterize valve when necessary.
 - a) Blowdown (depressurize) valve body.
 - b) Drain non-petroleum liquids (such as water) from valve body.
 - c) Operate injection equipment and inject appropriate antifreeze.
16. If valve is disassembled, internally inspect all parts and make any repairs according to manufacturer's procedures.
17. Document results.
18. Perform prompt remedial action to correct any valve that is found inoperable or designate another valve to use in case of an emergency until the inoperable valve is repaired.

Valve Specification

All valves (block, relief, service blowdown, etc.) and related equipment utilized in pipelines must meet the minimum standards outlined in API 6D. Each valve must be marked to indicate:

1. Manufacturer
2. Material



3. Size
4. Pressure or series rating
5. Specification standards to which it was manufactured

All valves installed in plastic pipe must be installed in a manner that protects pipe from excess torsional or shearing forces. This can be accomplished by:

1. Anchoring the valve to resist turning and rotation.
2. Making the transition from metal to plastic some distance from the valve. The transition must be well supported in compacted soil.

Rupture Mitigative Valves (RMV's)

To ensure the RMV is in good working condition, the above procedure steps will be followed.

Follow the steps below to ensure communication between the RMV's and SCADA is working properly, a point-to-point verification must be completed for the valves, sensors, and communications equipment.

1. Open zdscada website on computer or mobile
2. Navigate to Canadian Group – Perryton HCA valve
3. Click on Red shut down button
4. Notify appropriate personnel

At this time WTG has chosen not to use manually operated valves for a RMV. The review and revisions will be made accordingly if WTG decides to utilize manually operated valves in the future.

Inoperable or ineffective isolation valves

If it is found that a RMV is inoperable or unable to maintain effective isolation, the valve must be replaced as soon as practicable but no later than 12 months after it is found. If the valve cannot be replaced within the 12-month requirement, an extension may be request from PHMSA following directions found in CFR 192.18.

Within 7 days of finding a RMV that is inoperable or is unable to maintain effective isolation, an interim isolation response plan must be determined and documented to maintain public safety. For such plan, RMV valve spacing is not required.



Description	This procedure gives the steps to inspect DOT vaults. At this time West Texas Gas Utility, LLC. does not operate nor maintain any vaults which house pressure regulating and pressure limiting equipment.	
Regulatory Applicability	Each vault that is at least 200 cubic feet <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A and B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	Once each calendar year, not to exceed a 15 month interval.	
Reference	49 CFR 192.749	<i>Vault Inspection</i>
Forms / Record Retention	<i>F-192.749</i>	<i>Vault Inspection</i>
Related Specifications	None	
OQ Covered Task	1351	<i>Vault Inspection and Maintenance</i> (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Procedure Steps

1. General

- a) Once each calendar year, at intervals not exceeding 15 months, all vault locations greater than 200 cubic feet (5.66 cubic meters) shall be inspected to determine physical condition and that the vault is adequately ventilated. If gas is found in the vault all equipment in the vault must be inspected and any leaks must be repaired. The following procedures shall be utilized whenever entry into a vault is required. Prior to performing work within a vault, these procedures shall be reviewed to ensure adequate personnel are available and properly trained, and the appropriate equipment is available. All ventilating equipment should be inspected to determine that it is functioning properly. Extreme caution should always be taken when preparing to do work within a vault due to potentially hazardous atmospheres.

2. Safety Procedures

- a) Prior to entering a vault several safety precautions shall be taken. If possible, all motor vehicle engines shall be shut-off in the vicinity of a vault. If this is not possible, the exhaust shall be kept away from the vault opening. Inspect the vault cover to assure it is not a hazard to public safety. All sources of ignition shall not be permitted in the work area, unless it is required to perform the work. In those situations, care shall be taken to prevent accidental ignition (P-192.751 Protection Against Ignition). Safety equipment should be readily available at the work site and all personnel should be properly trained on its use. Adequate equipment shall be at the work location, such as:
 - i) dry chemical fire extinguishers,
 - ii) breathing apparatus, and
 - iii) safety harnesses.
- b) Any equipment used for lighting the work area, i.e. flashlights, lighting fixtures, or extension cords, shall be of the type approved for hazardous areas.
- c) The vault atmosphere shall be tested for combustible gas prior to removing the cover. This shall be performed by inserting a test probe into either the vent holes, pry holes, or by slightly lifting the cover. The probe shall be inserted no more than one foot within the vault. Once the cover is removed, further test shall be performed to determine the amounts of combustible gas and oxygen. These readings shall be taken at various levels within the vault. Depending on the results of this test one of the following two scenarios will apply.
 - i) Combustibles at 60% Lower Explosive Limit (3.0% natural gas in air) or less.
 - (1) The vault may be entered without a breathing apparatus after the following criteria has been met:
 - (2) either it has been tested that a safe oxygen level exists, or
 - (3) If ventilation can be adequately maintained through a forced draft method (suction draft ventilation is not as effective forced draft ventilation).
 - ii) Combustibles in excess of the 60% Lower Explosion Limit.



- (1) The vault should not be entered unless:
 - (a) Ventilation maintains the LEL below 60% and a safe oxygen level exists.
 - (2) If the vault cannot be properly ventilated and the facility cannot be taken out of service in order to complete the repairs necessary, then the vault shall be entered:
 - (a) With the use of an approved breathing apparatus and harness.
 - d) While working in the vault, ladders should be used for entry and exit. Once inside the vault, the interior shall be inspected for hazardous or unusual conditions. Repair work shall always be performed in teams of at least two individuals, depending on the circumstances. One person shall always remain on the surface at the vault site while the other performs the repair work. Should the use of breathing apparatus be required then two workers are required to remain on the surface at the vault site, one always observing the work which is being performed. Whenever work is being performed in a vault the atmosphere within the vault shall be regularly tested. Occurring at intervals of one hour the tests shall check for combustible gases and oxygen deficiency. Any type of electrical connections shall be made outside of the vault. Any electrical equipment that is utilized shall be approved for hazardous atmospheres.
3. Documentation and Records
- a) Vault Maintenance results will be documented on F-192.749 or equivalent.



Description	The purpose of this procedure is to establish safety practices that minimize the danger of accidental ignition of combustible gas mixtures in areas where the presence of gas constitutes a hazard of fire or explosion.
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input type="checkbox"/>
Frequency	Any time a hazardous amount of gas is being vented into open air or hot work is being performed.
Reference	49 CFR 192.751 <i>Prevention of Accidental Ignition</i> LA Title 43 Part XIII 2951 <i>Prevention of Accidental Ignition</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	None



Procedure Steps

1. Create exclusion areas as applicable.

At some spill or leak sites, it may be necessary to affix boundaries to keep out curious sightseers, because of hazards created by the operation of heavy equipment, the possibility of exposure to hazardous concentrations, or the potential of an accidental ignition. The use of warning stripe tape, keep-out signs, barricades, and security guards may be necessary to establish an exclusion area. Determining if the exclusion area is needed is a decision that is made as part of the emergency response to a spill or leak.

2. Post "No Smoking" signs to serve warning in hazardous areas.
3. Post temporary "No Smoking" signs in construction and maintenance areas as applicable.
4. Locate and remove any possible sources of ignition in an area before a hazardous amount of gas is vented into the atmosphere or in the presence of flammable liquids.
5. Do not use open flame devices in hazardous areas.
6. Use explosion proof flashlights, lighting fixtures, extension cords, and other electrical devices in hazardous areas.
7. Man fire extinguishers at all times during venting, cutting, and welding operations.
8. Take precautions to minimize the mixing of air with gas when welding or cutting.
9. Do not weld or cut on pipe or pipeline components that contain combustible mixture of gas and air in the area of work.
10. Use wire jumpers to prevent arcing from cathodic protection or induced currents when cutting or rejoining pipelines.

Additional Precautions and Guidelines for Performing Hot Work

1. Verify a zero percent reading on the explosive substance meter in the presence of mechanic performing the work.
2. Any oil spills and all flammable materials in the area must be removed.
3. Equipment must be blinded and valves closed as close to the equipment as possible (first flange).
4. Sewers must be covered with plywood, sand, and/or burlap/plastic. Sand must be wet down periodically.
5. Approved ventilating equipment must be in place and operating, when required.
6. Firefighting equipment must be ready for use at the job site.
7. Provide means of emergency entry and exit to the work area.
8. Surrounding conditions must be inspected and the necessary precautions taken. Consideration must be given to wind direction, ground slope, housekeeping, etc.



9. Emergency communication must be available for jobs requiring entry into confined spaces and work within 200 feet of a flare stack.
10. Equipment such as welding machines, gas bottles, hose, tools, etc., must be removed or located so as not to impede entry or exit.
11. Ensure that all rectifiers are turned off prior to starting maintenance work.
12. When maintenance work is performed on pipe, jumper cables must be used to prevent electrical arcing.
13. All burning and welding jobs must have a fire extinguisher and must be manned by a fireguard.
14. Welding machines must be located where there is no possibility for leaking hydrocarbons.
15. Welding machines must be located as close to the welding site as practical and must be properly grounded.
16. Appropriate signs shall be posted at each location or area where smoking and open flames are prohibited.
17. Any time it is necessary to use cutting tools, such as oxy-acetylene torch, or to weld in a compressor station, the work plan must be reviewed by the maintenance supervisor to ensure that the planned work is safe to perform.



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Description	This procedure describes the process of analysis and consideration of possible HCA's along the pipeline.
Frequency	As needed.
Reference	49 CFR 192.905 <i>How Does An Operator Identify a High Consequence Area?</i> LA Title 43 Part XIII 3305 <i>How Does An Operator Identify a High Consequence Area?</i>
Forms / Record Retention	None
Related Procedures	None
OQ Covered Task	None



Procedure Steps

Identification of High Consequence Areas

West Texas Gas (WTG) may elect to use Method 1 or Method 2 or a combination of the two to identify HCAs. The method selected for each Covered Segment is to be noted in the stand alone document showing the analysis for High Consequence Areas and a listing of any such areas.

Method 1

West Texas Gas may utilize Method 1 from the definition of High Consequence Areas in §192.903 to identify HCA's. In that case WTG will follow the procedure below.

1. The Pipeline Engineer will utilize WTG's most recent class location study to identify all Class 3 and Class 4 locations. All Class 3 and Class 4 locations are deemed to be HCAs.
2. For flammable gases, the Pipeline Engineer will utilize the formula found in the definition of Potential Impact Radius (PIR) located in §192.903 to calculate a PIR for each of West Texas Gas's pipelines.
3. For Class 1 and 2 locations, the Pipeline Engineer will create potential HCA maps by overlaying each pipeline's centerline onto recent aerial photographs of the Class 1 and Class 2 locations. The Pipeline Engineer will then create a potential HCA Buffer by placing a buffer equal to the Potential Impact Circle centered on the pipeline centerline and extending along the entire length of each Class 1 and Class 2 location.
4. The Pipeline Engineer will locate potential HCAs by identifying all potential Identified Sites and twenty or more buildings intended for human occupancy clusters within the HCA Buffer. The potential HCA will extend axially along the length of the pipeline from the outermost edge of the first potential impact circle¹ that contains either an Identified Site or twenty or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle containing either an Identified Site or twenty or more buildings intended for human occupancy.
5. The Pipeline Engineer will document the locations of potential HCAs on the aerial photo maps and have field personnel verify. Field personnel will verify each potential HCA location as shown on the maps by determining occupancy and use of structures and identified sites within the potential HCA. Then, where necessary, will use GPS equipment, electronic distance measuring equipment, or other equivalent means to map the Identified Site or structure.
6. Field personnel will also identify locations of additional Identified Sites or of twenty or more buildings intended for human occupancy not noted on the maps.

¹ As defined in [§192.903](#).



7. Field personnel will document their findings on the maps and return the maps to the Pipeline Engineer. Documentation must include the type of Identified Site, such as retail store, playground, school, etc. and the verification date.

Method 2

West Texas Gas may utilize Method 2 from the definition of High Consequence Areas in §192.903 to identify HCA's. In that case WTG will follow the procedure below.

1. For flammable gases, the Pipeline Engineer will utilize the formula found in the definition of PIR located in §192.903 to calculate the PIR for each of West Texas Gas's pipelines.
2. The Pipeline Engineer will create potential HCA maps by overlaying each pipeline's centerline onto recent aerial photographs showing the pipeline's centerlines. The Pipeline Engineer will then create a potential HCA Buffer by placing a buffer equal to the Potential Impact Circle centered on the pipeline centerline and extending along the entire length of the line.
3. The Pipeline Engineer will locate potential HCAs by identifying all potential Identified Sites and twenty or more buildings intended for human occupancy clusters within the HCA Buffer. The potential HCA will extend axially along the length of the pipeline from the outermost edge of the first potential impact circle² that contains either an Identified Site or twenty or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle containing either an Identified Site or twenty or more buildings intended for human occupancy.
4. The Pipeline Engineer will document the locations of potential HCAs on the aerial photo maps and forward to the field for verification. Field personnel will verify each potential HCA location as shown on the maps by determining occupancy and use of structures and identified sites within the potential HCA. Then, where necessary, will use GPS equipment, electronic distance measuring equipment, or other equivalent means to map the Identified Site or structure.
5. Field personnel will also identify locations of additional Identified Sites or of twenty or more buildings intended for human occupancy not noted on the maps.
6. Field personnel will document their findings on the maps and return the maps to the ALIMT. Documentation must include the type of Identified Site, such as retail store, playground, school, etc. and the verification date.

² As defined in [§192.903](#).



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Description	The purpose of this procedure is to ensure timely communications to the Commission, and the general public of the implementation of a restoration of service plan following an unplanned service interruption.
Regulatory Applicability	Service lines in the State of Oklahoma.
Frequency	As needed. The plan itself will be reviewed annually and updated as deemed necessary and appropriate.
Reference	OCC 165:45-9-2.1. <i>Restoration of Service</i>
Forms / Record Retention	None
Related Specifications	None
OQ Covered Task	None



Procedure Steps

1. Notify the OCC through the Director of the Consumer Services Division by business telephone¹ and/or e-mail address² during the business hours of 8:00 a.m. through 4:30 p.m. Monday through Friday; or emergency cellular telephone number after normal business hours, weekends and holidays.
Notification shall be made as follows
 - a. Initial contact to notify the staff of outages that involve a major utility substation or facility; one that may cause a high degree of public interest or concern; or one that has a potential duration of 4 hours or more and involves 1% or at least 50 customers (whichever is greater).
 - b. Intermediate contact to provide status reports, as deemed necessary by WTG Personnel or requested by the Commission Staff.
 - c. Conclusion contact detailing the results and completion of the restoration of service plan implementation.
 2. Assess the extent of the service interruption. Include:
 - a. the number of customers affected
 - b. the geographic extent of the service interruption
 3. Determine what resources, such as equipment, materials, and labor, will be required to restore service.
 4. Determine if the service restoration can be accomplished by the use of West Texas Gas personnel only, or if contractors will be required to have service restored as soon as possible.
 5. When time permits, make mass notification to all affected customers of the outage via company's Burst Tex software program with the following information.
 - a. type of service outage
 - b. extent of the service outage
 - c. expected time to restore service
- Note:** Other means of notification may also be used as long as the result is mass notification on an efficient, effective, and timely basis.
6. Identify the priorities for service restoration. Base the priorities on the following factors:
 - a. emergency needs
 - b. ease of restoration:
 - i. for the greatest number of consumers
 - ii. for the least expenditure of money, time and effort

Note: Priority will always be given to any life-threatening situations known or discovered during restoration of service.



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7. Once gas service to installations affected with the interest of public health and safety has been restored (such as hospitals, fire and police departments and 911 centers), service will then be restored to schools as quickly as feasible, during any time of the year that school is in session.

West Texas Gas Emergency Contact Number 1-844-976-0333

(405)521-2331
CS@occ.ok.gov



Description	This procedure is used to conduct a Removal and Replacement Program. The removal and replacement of compression couplings listed below will be complete by November 30, 2009.			
Regulatory Applicability	All DOT regulated gas lines that are not odorized. <input type="checkbox"/> Regulated Transmission Pipelines <input type="checkbox"/> Regulated Gathering Pipelines (Type A) <input type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines			
Frequency	As needed			
Reference	TAC 16 Chapter C 8.208 Mandatory Removal and Replacement Program			
Forms / Record Retention	F-TAC 8.208 Progress Report	Mandatory	Removal	and Replacement Program
Related Specifications	None			
OQ Covered Task	0691 Joining of Pipe – Non-Bottom Out Compression Couplings 0701 Joining of Pipe – Bottom Out Compression Couplings 0711 Joining of Pipe – Compression Couplings (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)			



Procedure Steps

1. For leaks identified on any underground compression coupling used to mechanically join steel pipe, either replace the leaking compression coupling or repair it using a sleeve welded over the compression coupling.
2. Repair or replace any compression coupling used to mechanically join steel pipe that is exposed during operation and maintenance activities unless determination can be made that the coupling was installed after 1980.
3. For leaks identified on any underground compression coupling used to mechanically join plastic pipe, remove and/or replace the leaking compression coupling.
4. For any other compression coupling used to join plastic pipe that is exposed during operation and maintenance activities, West Texas Gas will:
 - a. For plastic pipe two inches or less in diameter, replace or remove such coupling unless the coupling is designated as an ASTM (American Society for Testing and Materials) D2513 Category 1 type fitting.
 - b. For plastic pipe greater than two inches in diameter, replace or remove such coupling unless the coupling is designated as an [ASTM D2513](#) Category 1 or Category 3 type fitting.
5. Remove and replace all compression couplings at currently known service riser installations, identifiable by a meter number or a street address, if they are not manufactured and installed in accordance with [ASTM D2513](#) for Category 1 fittings.

Note: Beginning November 1, 2008 and every 6 months thereafter until all of these compression fittings have been removed and replaced, West Texas Gas will file a progress report with the Division showing the number of service riser installations checked, the condition of the coupling, and the total number of compression couplings replaced for that reporting period.
6. Ensure any coupling installed on plastic pipe after September 1, 2008, is designed to meet the requirements of [ASTM D2513](#) Category 1 and any coupling installed on steel pipe after September 1, 2008, meets the requirements of [49 CFR Part 192](#), §192.273.



Description	To implement TAC Rule 8.225 that requires the reporting of plastic pipe inventory.	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Distribution Pipelines	
Frequency	March 15 of every year	
Reference	16 TAC 8.225 CFR 192.513	<i>Plastic Pipe Requirements</i> <i>Testing Requirements for Plastic Pipelines</i>
Forms / Record Retention	WTG-1400	Project Report Form / Life of Pipeline System
Related Specifications	None	
OQ Task	Covered	None



Procedure Steps

- (1) For all new installations of plastic pipe, West Texas Gas shall record and maintain for the life of the pipeline the following information for each pipeline segment:
 - (A) System;
 - (B) Nominal pipe size;
 - (C) Material designation code;
 - (D) Pipe category; and
 - (E) Pipe manufacturer
 - (F) Pipe manufactured date
 - (G) Pipeline test pressure and date tested
 - (H) Length of installation
 - (I) Location of installation
- (2) West Texas Gas shall annually report to the Division the amount of plastic pipe in natural gas service as of December 31 of the previous year. The amount of plastic shall be determined by a review our records and shall be reported electronically in a format specified by the Commission. The report shall include the following:
 - (A) System;
 - (B) Miles of pipe;
 - (C) Calendar year of installation;
 - (D) Nominal pipe size;
 - (E) Pipe category; and
 - (F) Pipe manufacturer.
- (3) The pipeline data will be recorded and maintained for the life of the pipeline using Form WTG-1400.



Description	To implement the requirements for testing of natural gas piping systems in school facilities	
Regulatory Applicability	<input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines <input checked="" type="checkbox"/> Regulated Distribution Pipelines <input checked="" type="checkbox"/> Regulated Production Pipelines – Texas Intrastate	
Frequency	Prior to beginning of school year as required per TAC 8.230.	
Reference	16 TAC 8.230	School Piping Testing
	16 TAC 8.235	<i>Natural Gas Pipelines Public Education and Liaison</i>
Forms	TX Form PS-86-A	Gas Pipe Testing Form / 2 Years or until Next Review whichever is Longer
	TX Form PS-86-B	Gas Pipe Test Results Form / 2 Years or until Next Review whichever is Longer
Related Specifications	None	
OQ Task	Covered	None



Procedure Steps

Notification of Schools

- Prior to the beginning of each school year West Texas Gas will verify which schools in each assigned District are required to submit to WTG their written notification of compliance with Texas Utility Code 121.5005-121.507.
- Schools that have not met TUC 121.5005-121.507 will be notified by WTG prior to the beginning of each school year by written notification of their responsibility to have the gas pipelines within their school system tested in accordance with *TAC 8.230 School Piping Testing*.
- If prior to the beginning of the school year WTG has not received notice from the school regarding the completion of the school piping testing, WTG will terminate all gas service as required by TAC 8.230 School Piping Testing.
- If WTG receives notification of a hazardous leak in the school facility pipeline. WTG will terminate all gas service.

Pressure Testing

A pressure test to determine if the natural gas piping in each school facility will hold at least normal operating pressure will be performed as follows:

- School facility pipe testing includes all gas piping from the outlet of the purchase meter to each inlet valve of each appliance.
- For systems on which the normal operating pressure is less than 0.5 psig, the test pressure will be 5 psig and the time interval will be 30 minutes.
- For systems on which the normal operating pressure is 0.5 psig or more, the test pressure shall be 1.5 times the normal operating pressure or 5 psig, whichever is greater, and the time interval shall be 30 minutes.
- A pressure test using normal operating pressure shall be utilized only on systems operating at 5 psig or greater, and the time interval shall be one hour.

Providing Information to the School District

Upon written request from the school district, West Texas Gas will provide (in writing) the following parts of the *Emergency Response Plan* (ERP) relevant to the school, including:

- Description and map of the pipeline and/or facilities that are within 1,000 feet of the school facility;
- List of products transported through the pipeline segment that is within 1,000 feet of the school building or facility;
- Designated emergency number for the pipeline facility operator;



- Information on the state's excavation One-Call system; and
- Information on how to recognize report and respond to a product release.

Written reports to school facilities will be mailed by certified mail, return receipts requested, to the Superintendent of the school district in which the school building or facility is located.

Appearing at School Board Meetings

When requested by the school board, West Texas Gas or a representative will appear at regularly scheduled meetings of the school board to explain any items listed above.

Record Keeping

West Texas Gas will keep and maintain all forms, PS-86-A & PS-86-B, for a minimum of two years



Description	Hot work: Is defined as any work activity which the heat used or generated by the work is intense enough to cause ignition of any flammable or combustible liquids, gases, or other combustible material.
Regulatory Applicability	All aboveground pipelines or portions of a pipeline <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	Each time Work is performed inside a building such as but not limited to Compressor buildings, Town borders, Meter buildings, vaults, Well site buildings. Where combustible gasses and vapors exist under normal operating conditions or could exist under abnormal operating conditions.
Reference	
Forms / Record Retention	Hot Work Permit Form 30 days after completion unless there is an incident associate with the work being completed.
Related Specifications	Any WTG employee completing fire prevention training can issue a Hot Work Permit. The person issuing the permit and the person performing the work may also be the same person.
OQ Covered Task	OQ requirements are task specific, review these requirements with District Manager or Operations Manager or OQ Administrator



Safety Precautions

The following precautions should be taken while conducting this procedure: Safety precautions should be observed during hot work. These precautions should include, but are not limited to:

- 1) Proper PPE for tasks being complete.
- 2) No welding, other than approved hot tapping, spark producing equipment such as internal combustion engines, electric motors, electric switches, cell phones or other ignition sources shall be introduced around or on piping, stations containing a flammable substance unless, the contents have been rendered inert by testing LEL with a CGI or other means.
- 3) Prohibit smoking and open flames in area.
- 4) Complete Hot Work Permit Inspection and document findings on Hot Work Form.
- 5) Post warning signs and/or barricade area to prevent public access.
- 6) Provide a fire extinguisher of appropriate type and size at the hot work area.

Procedure Steps

- 1) Conduct tailgate meeting prior to hot work on the pipeline. Discuss the following, but not limited to:
 - a) Task to be completed.
 - b) Location of personnel and their duties.
 - c) Completion of Inspection/Documentation of Hot Work Permit
 - i) Proper PPE for task.
 - ii) Sequence of valve operations.
 - iii) Ensure valves have been closed and lock out and tag out procedure has been followed.
 - iv) Atmosphere been checked with CGI.
 - v) Location of firefighting equipment.
 - vi) Fire watch assigned.
 - d) The use of a CGI during the length of time for task at hand.
 - e) Always be aware of weather conditions such as (wind direction, thunder storms, etc.) and its effects concerning surrounding facilities for possible ignition sources.
 - f) A review of the impact on facilities and customers (including points of receipts, delivery and farm taps) including both upstream and downstream. Affected customers shall be notified prior to work being started.



- g) Work area been checked for possible venting gas.
- h) The Work Permit is valid for the work day indicated on the permit. Due to changing conditions in the work place, a new work permit will be required in the event of significant changes to work conditions or if work is delayed to the next day.
- i) Permit copies will be retained for a minimum of 30 days from project completion. In the event that the project is involved in a reportable incident, the record will be kept for the life of the system.



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Description	To establish a uniform process and outline precautions for launching and receiving any type of pipeline pig.
Regulatory Applicability	All aboveground pipelines or portions of a pipeline <input checked="" type="checkbox"/> Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Distribution Pipelines
Frequency	Each time any pig is to be launched or received
Reference	
Forms / Record Retention	None
Related Specifications	Pigging Procedure
OQ Covered Task	0301 Manually Opening and Closing Valves 0311 Adjust and Monitor Flow or Pressure Manual Valve Operation 1801 Purging, abandonment, or inactivation or facilities. (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)



Safety Precautions

Launcher and receiver safety

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

The following precautions should be taken while conducting this procedure: Safety precautions should be observed during this launching or receiving process. These precautions should include, but are not limited to:

- 1) Proper PPE.
- 2) Prohibit smoking and open flames in area.
- 3) Prohibit operation of spark producing equipment such as internal combustion engines, electric motors, switches, cell phones, or other ignition sources.
- 4) Post warning signs and/or barricade area to prevent public access.
- 5) Provide a fire extinguisher of appropriate type and size at the launching or receiving facilities.

Launching Procedure Steps

1. The pig trap valve and kicker valve must be closed.
2. Open the blowdown valve to vent pressure from the launcher. (WARNING: Do not attempt to open the end closure until the launcher is completely blown down to atmospheric pressure.)
3. Open the end closure and insert the pig until the front cup reaches the reducer and forms a tight fit against the reducer.
4. Close the end closure.
5. Open the kicker valve slightly to purge air from the launcher.
6. Close the blowdown valve and slowly bring the launcher up to line pressure.
7. Close the kicker valve. (CAUTION: Kicker valve and isolation valve will need to be opened slowly to ensure equal pressure on both sides of the pig is maintained to prevent pig moving up against isolation valve or jumping backwards into the oversize pipe.)



-
8. Open the pig trap valve.
 9. Open the kicker valve. (NOTE: If the pig does not leave the launcher immediately, slowly close the mainline isolation valve (partially) until the pig does leave the launcher.)
 10. Open the mainline isolation valve.
 11. Close the kicker and pig trap valves.
 12. Verify the pig has left the trap. (Repeat steps 2 – 4 to check for the pig.)

Receiving Procedure Steps

1. The blowdown valve and end closure must be closed.
2. Before the pig arrives, open the bypass and then open the pig trap valve. (NOTE: If the pig does not enter the trap, slowly close the station valve until the pig is forced into the trap.)
3. Once the pig is in the trap, open the station valve.
4. Close the pig trap valve and bypass valve.
5. Open the blowdown valve to vent pressure from the receiver. (WARNING: Do not attempt to open the end closure until the launcher is completely blown down to atmospheric pressure.)
6. Open end closure and remove pig(s). (CAUTION: Some internal pipeline residues may smolder and ignite when exposed to the atmosphere.)
7. Close end closure.
8. Open the bypass valve slightly to purge air from the barrel.
9. Close blowdown valve and slowly bring receiver up to line pressure.
10. Close bypass valve. (The bypass valve and trap may valve may be opened at this time to be ready for the next pig.)



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**When to Use This
Form**

This packet is to be used in conjunction with Procedure P-191.5: Reporting Incidents whenever a pipeline incident occurs to provide for notification, reporting, and investigation of the incident.

**Reviewed
Procedures**

- ☐ P-191.5 Incident Reporting
☐ P-192.617 Investigation of Incidents and Failures

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this packet and replace original in manual. Do not mark up the original copy of this form.
2. Complete Initial Notification section on Page 2.
3. Immediately initiate emergency plan procedures.
4. If the incident requires a telephonic report, complete the telephonic notification section of this packet.
5. Gather data on the following pages as it becomes available for use in the root cause analysis and determine if procedures were adequate for handling the incident.
6. Within 30 days of the incident, complete PHMSA Form F-7100.2 (attached) and submit to Regulatory Manager for approval. This form must be submitted by mail according to Procedure P-191.5 or submitted electronically here: <http://opsweb.rspa.dot.gov/cfdocs/opsapps/pipes/main.cfm>
7. As additional information becomes available, update this packet and send supplemental reports (within 30 days of availability) to PHMSA and the appropriate State regulator.
8. Create a file in the DOT files for this incident and file all information concerning it and a copy of this entire packet there.
9. Retain Record for the Life of the Pipeline System.



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INITIAL NOTIFICATION

Location	<input type="checkbox"/> Onshore <input type="checkbox"/> Offshore <input type="checkbox"/> Inland body of water (Name):		
	Pipeline within right-of-way of:		
	<input type="checkbox"/> Railroad <input type="checkbox"/> Paved road/street <input type="checkbox"/> Highway		
	Pipeline station number:		
	Pipeline system:		Location code:
	Street address:		
	City:		County:
Nearest major landmark:			
Operator Information	Operator:		
	Street address:		
	City:	County:	State:
Reporter Info.	Name:		
	Title:	Telephone:	
Significant Facts	Date of incident:		Time of incident:
	Number of fatalities	Operator:	Public:
	Number of injuries	Operator:	Public:
	Commodity transported:		
	Other:		
Completed by:			Date:



TELEPHONIC NOTIFICATION

Louisiana (504) 342-5585 (working hours) (504) 342-5505 (after hours)	Texas (512) 463-6788 (24 hours)	National Response Center (800) 424-8802 (24 hours)
(Name of Individual Receiving Report)	(Name of Individual Receiving Report)	(Name of Individual Receiving Report)
Name of affiliate operating involved pipeline:		
Name of employee making the initial notification:		
Telephone number where reporting employee may be reached:		
System name/line number:		
Incident location: (Give reference relative to the nearest street address, town, city, county, parish, and state; or nearest offshore platform or other appropriate landmarks)		
Date and time incident occurred: (Estimate if not known exactly)	Date:	
	Time: <input type="checkbox"/> A.M. <input type="checkbox"/> P.M.	
Number of fatalities:		
Number of personal injuries:		
Number of injuries requiring hospitalization:		
Preliminary estimated cost of property damage: (Include damage to facilities and third-party damages.)		
Preliminary estimated cost of unintentional gas loss (at average purchase price), if over three million cubic feet:		
Known facts relevant to cause of incident (do not speculate):		
Description of damages:		



INVESTIGATION DATA

Detection	Was the incident detected promptly? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	How was it detected? By whom?
	Could it have been detected earlier? <input type="checkbox"/> No <input type="checkbox"/> Yes; explain:
Notification Investigation	Were proper procedures followed in notifying government agencies? <input type="checkbox"/> Yes <input type="checkbox"/> No; explain discrepancies/omissions:
	Were notifications prompt? <input type="checkbox"/> Yes <input type="checkbox"/> No; explain:
	Was management notified promptly? <input type="checkbox"/> Yes <input type="checkbox"/> No; explain:
	Was management response appropriate? <input type="checkbox"/> Yes <input type="checkbox"/> No; explain:
Origin	Incident occurred on: <input type="checkbox"/> Pipe <input type="checkbox"/> Compressor <input type="checkbox"/> Valve <input type="checkbox"/> Pig Trap <input type="checkbox"/> Weld; Type: <input type="checkbox"/> Fitting; Type: <input type="checkbox"/> Other:
	Type of Failure: <input type="checkbox"/> Leak <input type="checkbox"/> Rupture <input type="checkbox"/> Other:
Origin	If the failure was caused by a rupture, how long was the rupture?
	Material involved: <input type="checkbox"/> Steel <input type="checkbox"/> Plastic <input type="checkbox"/> Other:
	Part of System Involved: <input type="checkbox"/> Pipeline <input type="checkbox"/> Compressor station <input type="checkbox"/> Other:



	Year the part of system involved was installed:	
	Class location of incident:	
Material Specification	Nominal pipe size: _____ in.	Wall thickness: _____ in
	Specification:	SMYS:
	Seam type:	Valve type:
	Manufactured by:	Year installed:
Environment	Where was the incident: <input type="checkbox"/> Under pavement <input type="checkbox"/> Above ground <input type="checkbox"/> Underground <input type="checkbox"/> Other:	
Corrosion Failure	Was the incident caused by corrosion? <input type="checkbox"/> No; Skip this section <input type="checkbox"/> Yes; Complete this section	
	Where did the corrosion occur? <input type="checkbox"/> Internally <input type="checkbox"/> Externally	
Corrosion Failure	Visual description: <input type="checkbox"/> Localized pitting <input type="checkbox"/> General corrosion <input type="checkbox"/> Other:	
	Cause: <input type="checkbox"/> Galvanic <input type="checkbox"/> Other:	
	Pipe coating: <input type="checkbox"/> Bare <input type="checkbox"/> Coated	
	Was corroded part of the pipeline considered to be under cathodic protection prior to discovering incident? <input type="checkbox"/> Yes; year protection began: <input type="checkbox"/> No	



Line Pipe Failure	Nominal diameter:	in.	SMYS:	psi
	Wall thickness:	in.	MAOP:	psi
	Type of joint: <input type="checkbox"/> Welded <input type="checkbox"/> Flanged <input type="checkbox"/> Threaded <input type="checkbox"/> Coupled <input type="checkbox"/> Other:			
	Pipe was: <input type="checkbox"/> Buried <input type="checkbox"/> Submerged <input type="checkbox"/> Above ground			
	Pressure at location at time of incident			psig
	Had there been a pressure test on the system? <input type="checkbox"/> No; Skip this section <input type="checkbox"/> Yes; Complete this section			
	Date of latest test:			
	Duration of test:			
	Maximum test pressure:			psig
Outside Damage Failure	Was failure caused by damage from outside forces? <input type="checkbox"/> No; Skip this section <input type="checkbox"/> Yes; Complete this section			
	Primary causes of incident: <input type="checkbox"/> Damage resulted from action of operator or their agent <input type="checkbox"/> Damage resulted from action of outside party/third party <input type="checkbox"/> Damage by earth movement <input type="checkbox"/> Subsidence <input type="checkbox"/> Landslide/washout <input type="checkbox"/> Frost <input type="checkbox"/> Other: <input type="checkbox"/> Damage by lightning or fire			
	Locating information (for damage resulting from action of outside party/third party): Did operator get prior notification that equipment would be used in the area? <input type="checkbox"/> No <input type="checkbox"/> Yes; Date received: Was pipeline location marked either as result of notification or by markers already in place? <input type="checkbox"/> No <input type="checkbox"/> Yes			



	<input type="checkbox"/> Permanent markers <input type="checkbox"/> Temporary stakes <input type="checkbox"/> Other:	
Construction Defect Failure	Was the failure caused by a construction defect? <input type="checkbox"/> No; Skip this section <input type="checkbox"/> Yes; Complete this section	
	<input type="checkbox"/> Poor workmanship during construction <input type="checkbox"/> Operating procedure inappropriate <input type="checkbox"/> Error in operating application <input type="checkbox"/> Physical damage during construction <input type="checkbox"/> Other:	
Operator Error	List all personnel whose performance may have contributed to the incident.	
	Name	Date of Last OQ Evaluation
<i>Note: Refer to OQ Plan for information on how to handle these personnel and their performance of covered tasks.</i>		



Assessment / Evaluation	<p>Was the magnitude of the problem assessed correctly at start?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>What means were used for this assessment?</p>
	<p>Are any guides or aids needed to assist leak evaluation?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain</p>
	<p>What sources of information were available on wind currents?</p> <p>Is this information adequate?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p> <p>Was the information useful (and used) for gas dispersion?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p> <p>Were such forecasts realistic?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>Is there adequate information on the specific gas properties?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
Mobilization	<p>What steps were taken to end gas release?</p>
	<p>Was mobilization prompt?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
Mobilization	<p>Could it have been faster, or should it have been?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>



	<p>Was mobilization of labor resources adequate?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
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	<p>Was local agency responsible for fire containment used appropriately?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p> <p>How could this be improved?</p>
	<p>What equipment/resources were mobilized?</p> <p>Were they utilized effectively?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>What other resources were available?</p> <p>Why weren't they used?</p>
Response - Strategy	<p>Is there an adequate emergency response plan for the location?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>Is it flexible enough to cope with unexpected events?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
Response - Strategy	<p>Does the plan include clear understanding of local environmental sensitivities?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>What was the initial strategy for response to this incident?</p> <p>Is this strategy defined in the emergency plan?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p>
	<p>How did strategy evolve and change during this leak and how were these changes implemented?</p> <p>What caused the changes?</p>



	Are improvements in the plan needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Is more training needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
Response - Resources	What outside resources were mobilized? How were they mobilized?
	Did utilization of resources change with time? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:



Response - Resources	Were resources used effectively?		
	Resource	Yes/No	Explain
		What changes would have been useful?	
	Do we have adequate knowledge of resource availability? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:		
Command Structure	Who was initially in charge of the emergency response?		
	Was there a clear command structure maintained? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:		
	What sort of organization was initially set up?		
Command Structure	Did this change with time? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:		
	What changes would have been useful?		



	<p>Was there adequate surveillance?</p> <p><input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p> <p>Should there be any changes?</p> <p><input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>
--	--



	<p>Were communications adequate? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:</p> <p>What improvements are needed?</p>
	<p>Was support from financial services adequate? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p> <p>Should there be any changes? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>
	<p>Is more planning needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>
	<p>Should financial procedures be developed to handle such incidents?</p>
	Measurements
<p>Should better measurement procedures be developed for either phase of operations? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>	
Government Relations	<p>What were the roles and effects of the various government agencies involved?</p>
	<p>Was there a single focal point among the government agencies for contact? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>



	<p>Should there have been better focus of communications to the agencies?</p> <p><input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:</p>
--	--



	Were government agencies adequately informed at all stages? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Could fewer agencies have been involved? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Are any changes needed in procedures to manage government relations? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
Government Relations	Was there adequate agreement with the government agencies on criteria for remediation? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain: How was the agreement developed?
	Were we too agreeable with the agencies in accepting their requests for specific action items? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
Public Relations	How were relations with the media handled? What problems were encountered? Are improvements needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Could we have handled matters differently to reduce public outcry?
	Would it be useful to undertake a public information effort to educate reporters about gas leaks? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:



Losses	There were:		
	_____ Fatalities		
	_____ Personal injuries requiring inpatient hospitalization		
	_____ Personal injuries requiring outpatient care		
	_____ Personal injuries not requiring a hospital		
Summary	Cost of	Estimated	Actual
	Remediation		
	Fire Control & Cleanup		
	Fires		
	Disposal		
	Lost Cargo		
	Legal Fees		
	Company Team (wages & expenses)		
	Money paid by insurance company		
	How could expenses have been reduced?		
	Things done right:		
	Improvements needed:		



	What lessons were learned?			
Summary	Changes to be Made	Personnel Responsible	Expected	Actual
Investigation Closed on (Date):				
Area Superintendent Signature			Date:	
Area Manager Signature			Date:	



**When to Use
This Form**

This Packet is to be used in conjunction with Procedure P-191.5 whenever a pipeline incident occurs to provide for notification, reporting, and investigation of the incident.

**Reviewed
Procedures**

- ☐ P-191.5 *Incident Reporting*
☐ P-192.617 *Investigation of Incidents and Failures*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this packet and replace original in manual. Do not mark up the original copy of this form.
2. Complete Initial Notification section on page 2.
3. Immediately initiate Emergency Plan procedures.
4. If the incident requires a telephonic report complete the telephonic notification section of this packet.
5. Gather data on the following pages as it becomes available for use in the root cause analysis and determine if procedures were adequate for handling the incident.
6. Within 30 days of the incident complete PHMSA Form F 7100.1 (attached) and submit to Regulatory Manager for approval. This form must be submitted by mail according to procedure P-191.5 or submitted electronically here:
<http://opsweb.rspa.dot.gov/cfdocs/opsapps/pipes/main.cfm>
7. As additional information becomes available, update this packet and send supplemental reports (within 30 days of availability) to PHMSA and the appropriate state regulator.
8. Create a file in the DOT files for this incident and file all information concerning it and a copy of this entire packet there.
9. Retain Record for the Life of the Pipeline System.



Initial Notification

Location	<input type="checkbox"/> Onshore <input type="checkbox"/> Offshore <input type="checkbox"/> Inland Body of Water (Name):		
	Pipeline within Right-of-way of: <input type="checkbox"/> Railroad <input type="checkbox"/> Paved Road/Street <input type="checkbox"/> Highway		
	Pipeline Station Number:		
	Pipeline System:		Location Code:
	Street Address:		
	City:	County:	State:
	Nearest Major Landmark:		
Operator Information	Operator:		
	Street Address:		
	City:	County:	State:
Reporter Info.	Name:		
	Title:		Telephone:
Significant Facts	Date of incident:		Time of incident:
	Number of Fatalities	Operator:	Public:
	Number of Injuries	Operator:	Public:
	Commodity Transported:		
	Other:		
Completed by:			Date:



Telephonic Notification

Louisiana (504) 342-5585 (working hours) (504) 342-5505 (after hours)	Texas (512) 463-6788 (24 hours)	National Response Center (800) 424-8802 (24 hours)
(Name of Individual Receiving Report)	(Name of Individual Receiving Report)	(Name of Individual Receiving Report)
Name of Company Affiliate Operating Involved Pipeline:		
Name of Employee Making the Initial Notification:		
Telephone Number Where Reporting Employee may be Reached:		
System Name/Line Number:		
Incident Location: (Give reference relative to the nearest street address, town, city, county, parish, and state; or nearest offshore platform or other appropriate landmarks.)		
Date and Time Incident Occurred (estimate if not known exactly):	Date:	Time: <input type="checkbox"/> A.M. <input type="checkbox"/> P.M.
Number of Fatalities:		
Number of Personal Injuries:		
Number of Injuries Requiring Hospitalization:		
Preliminary Estimated Cost of Property Damage: (Include damage to Company Facilities, Third-Party Damages, and Cost of Lost Gas (at average purchase price))		
Description of Damages:		
Known Facts Relevant to Cause of Incident (DO NOT SPECULATE):		

Investigation Data

Detection	Was the incident detected promptly? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
	How was it detected? By whom?	
	Could it have been detected earlier? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:	
Notification Investigation	Were proper procedures followed in notifying government agencies? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain discrepancies/omissions:	
	Were notifications prompt? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
	Was management notified promptly? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
	Was management response appropriate? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
Origin	Incident Occurred on: <input type="checkbox"/> Pipe <input type="checkbox"/> Compressor <input type="checkbox"/> Valve <input type="checkbox"/> Pig Trap <input type="checkbox"/> Weld; Type: <input type="checkbox"/> Fitting; Type: <input type="checkbox"/> Other:	
	Type of Failure: <input type="checkbox"/> Leak <input type="checkbox"/> Rupture <input type="checkbox"/> Other:	
	If the failure was caused by a rupture, how long was the rupture?	
	Material Involved: <input type="checkbox"/> Steel <input type="checkbox"/> Plastic <input type="checkbox"/> Other:	
	Part of System Involved: <input type="checkbox"/> Pipeline <input type="checkbox"/> Compressor Station <input type="checkbox"/> Other:	
	Year the Part of System Involved was Installed:	
	Class location of incident:	
5 a s p e c i f i c	Nominal Pipe Size: _____ in.	Wall thickness: _____

	Specification:	SMYS:
	Seam Type:	Valve Type:
	Manufactured By:	Year Installed:
Environment	Where was the incident: <input type="checkbox"/> Under Pavement <input type="checkbox"/> Above Ground <input type="checkbox"/> Under Ground <input type="checkbox"/> Other:	
Corrosion Failure	Was the incident caused by corrosion? <input type="checkbox"/> No; skip this section <input type="checkbox"/> Yes; complete below:	
	Where did the Corrosion occur? <input type="checkbox"/> Internally <input type="checkbox"/> Externally	
	Visual Description: <input type="checkbox"/> Localized Pitting <input type="checkbox"/> General Corrosion <input type="checkbox"/> Other:	
	Cause: <input type="checkbox"/> Galvanic <input type="checkbox"/> Other:	
	Pipe Coating: <input type="checkbox"/> Bare <input type="checkbox"/> Coated	
	Was Corroded part of the pipeline considered to be under Cathodic Protection prior to discovering incident? <input type="checkbox"/> Yes; Year protection began: <input type="checkbox"/> No	
Line Pipe Failure	Nominal Diameter:	in.
	Wall thickness:	in.
	Type of joint:	<input type="checkbox"/> Welded <input type="checkbox"/> Flanged <input type="checkbox"/> Threaded <input type="checkbox"/> Coupled <input type="checkbox"/> Other:
	Pipe was:	<input type="checkbox"/> Buried <input type="checkbox"/> Submerged <input type="checkbox"/> Above Ground
	Pressure at location at time of incident	psig
	Had there been a pressure test on the system?	<input type="checkbox"/> No <input type="checkbox"/> Yes; complete below
	Date of latest test:	Duration of test:
	Maximum test pressure:	psig
Damage Failure	Was failure caused by damage from outside forces? <input type="checkbox"/> No; skip this section <input type="checkbox"/> Yes; complete below:	



	<p>Primary causes of incident</p> <p><input type="checkbox"/> Damage resulted from action of operator or his agent.</p> <p><input type="checkbox"/> Damage resulted from action of outside party / third party.</p> <p><input type="checkbox"/> Damage by earth movement.</p> <p><input type="checkbox"/> Subsidence <input type="checkbox"/> Landslide / washout</p> <p><input type="checkbox"/> Frost <input type="checkbox"/> Other:</p> <p><input type="checkbox"/> Damage by lightning or fire.</p>
	<p>Locating information (for damage resulting from action of outside party / third party)</p> <p>Did operator get prior notification that equipment would be used in the area?</p> <p><input type="checkbox"/> No <input type="checkbox"/> Yes; Date received:</p> <p>Was pipeline location marked either as result of notification or by markers already in place?</p> <p><input type="checkbox"/> No <input type="checkbox"/> Yes</p> <p><input type="checkbox"/> Permanent markers <input type="checkbox"/> Temporary stakes <input type="checkbox"/> Other:</p>
Construction Defect Failure	<p>Was the failure caused by a construction defect?</p> <p><input type="checkbox"/> No; skip this section</p> <p><input type="checkbox"/> Yes; complete below:</p>
	<p><input type="checkbox"/> Poor workmanship during construction</p> <p><input type="checkbox"/> Operating procedure inappropriate</p> <p><input type="checkbox"/> Error in operating application</p> <p><input type="checkbox"/> Physical damage during construction</p> <p><input type="checkbox"/> Other:</p>



Operator Error	List all personnel whose performance may have contributed to the incident:								
	<table border="1"><thead><tr><th>Name</th><th>Date of Last OQ Evaluation</th></tr></thead><tbody><tr><td> </td><td> </td></tr><tr><td> </td><td> </td></tr><tr><td> </td><td> </td></tr></tbody></table>	Name	Date of Last OQ Evaluation						
	Name	Date of Last OQ Evaluation							
Note: Refer to OQ Plan for information on how to handle these personnel and their performance of covered tasks.									
Assessment/Evaluation	Was the magnitude of the problem assessed correctly at start? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:								
	What means were used for this assessment?								
	Are any guides or aids needed to assist leak evaluation? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:								
	What sources of information were available on wind currents?								
	Is this information adequate? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:								
	Was the information useful (and used) for gas dispersion? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:								
	Were such forecasts realistic? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:								
Is there adequate information on the specific gas properties? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:									



Mobilization	What steps were taken to end gas release?
	Was mobilization prompt? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Could it have been speeded up or should it have been? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Was mobilization of manpower resources adequate? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Was local agency responsible for fire suppression used appropriately? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain: How could this be improved?
	What company equipment/resources were mobilized? Were they utilized effectively? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	What other company resources were available? Why weren't they used?



Response - Strategy	Is there an adequate emergency response plan for the location? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Is it flexible enough to cope with unexpected events? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Does the plan include clear understanding of local environmental sensitivities? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	What was the initial strategy for response to this incident?
	Is this strategy defined in the emergency plan? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	How did strategy evolve and change during this leak and how were these changes implemented?
	What caused the changes?
	Are improvements in the plan needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
Is more training needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:	



Response - Resources	What outside resources were mobilized?					
	How were they mobilized?					
	Did utilization of resources change with time? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:					
	Were resources used effectively?					
		Resource	Yes	No	Explain	
		Contractors	<input type="checkbox"/>	<input type="checkbox"/>		
		Government Agencies	<input type="checkbox"/>	<input type="checkbox"/>		
		Company	<input type="checkbox"/>	<input type="checkbox"/>		
		Cooperatives	<input type="checkbox"/>	<input type="checkbox"/>		
		Volunteers	<input type="checkbox"/>	<input type="checkbox"/>		
	Consultants	<input type="checkbox"/>	<input type="checkbox"/>			
	Other	<input type="checkbox"/>	<input type="checkbox"/>			
	What changes would have been useful?					
	Do we have adequate knowledge of resource availability? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:					



Command Structure	Who was initially in charge of the emergency response?
	Was there a clear command structure maintained? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	What sort of organization was initially set up?
	Did this change with time? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	What changes would have been useful?
	Was there adequate surveillance? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Should there be any changes? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Were communications adequate? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	What improvements are needed?
	Was support from financial services adequate?
	Should there be any changes? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
Is more planning needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:	
Should financial procedures be developed to handle such incidents?	
Measurements	Was there adequate measurement or estimation of the volume released? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Should better measurement procedures be developed for either phase of operations? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:



Government Relations	What were the roles and effects of the various government agencies involved?
	Was there a single focal point among the government agencies for contact? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Should there have been better focus of communications to the agencies? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Were government agencies adequately informed at all stages? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	Were too many agencies involved? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Are any changes needed in procedures to manage government relations? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	Was there adequate agreement with the government agencies on criteria for remediation? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:
	How was the agreement developed?
Public Relations	Were we too agreeable with the agencies in accepting their requests for specific action items? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	How were relations with the media handled?
	What problems were encountered?
	Are improvements needed? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	How could public outcry have been reduced?
Losses	Would it be useful to undertake a public information effort to "educate" reporters about gas leaks? <input type="checkbox"/> No <input type="checkbox"/> Yes; Explain:
	There were:
	_____ Fatalities
	_____ Personal injuries requiring inpatient hospitalization
	_____ Personal injuries requiring outpatient care
_____ Personal injuries not requiring a hospital	



Summary					
		Cost of	Estimated	Actual	
		Remediation			
		Fire control & Cleanup			
		Fires			
		Disposal			
		Lost Cargo			
		Legal Fees			
		Company team (wages & expenses)			
		Money paid by insurance company			
	How could expenses have been reduced?				
	Things done right:				
Improvements:					
What lessons were learned?					
Summary		Changes to be made	Personnel Responsible	Completion Date	
				Expected	Actual
	Investigation closed on (Date):				
Area Superintendent Signature			Date:		
Area Manager Signature			Date:		



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**When to Use
This Form**

This form is used in conjunction with procedure P-191.11 to report pipelines to the Federal DOT every March.

**Reviewed
Procedures**

☐ P-191.11 *Annual Report*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and replace the original in manual.
2. Type or print all entries.
3. Make an entry in each block for which data is available. Estimate data if necessary. Try to avoid entering mileage in the Unknown columns if possible.
4. Copy completed form and place into DOT file.
5. Mail original by March 1 (DOT must receive by March 15th) to:

Information Resources Manager
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
400 7th St., S.W., Room 7128
Washington, D.C. 20590
6. Or file online at this address:

<http://opsweb.rsapa.dot.gov/cfdocs/opsapps/pipes/main.cfm>
7. Retain Records for 5 Years



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**When to Use
This Form**

This form is used in conjunction with procedure P-191.17 to report pipelines to the Federal DOT every March.

**Reviewed
Procedures**

☐ P-191.17 *Annual Report*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and replace the original in manual.
2. Type or print all entries.
3. Make an entry in each block for which data is available. Estimate data if necessary. Try to avoid entering mileage in the Unknown columns if possible.
4. Copy completed form and place into DOT file.
5. Mail original by March 1(DOT must receive by March 15th) to:
Information Resources Manager
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
400 7th St., S.W., Room 7128
Washington, D.C. 20590
6. Or file online at this address:
<http://opsweb.rspa.dot.gov/cfdocs/opsapps/pipes/main.cfm>
7. Retain Records for 5 Years



**When to Use
This Form**

Anytime there is a Safety Related Condition on the pipeline (as determined in P-192.23), this form should be completed.

**Reviewed
Procedures**

☐ P-191.23 *Reporting Safety Related Conditions*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and place blank original back in file. Refer to procedure P-191.23.
2. Gather data and complete form.
3. Have Supervisor sign form.
4. Fax completed form to (202) 366-7128 (Federal PHMSA).
5. In Texas, Fax complete form to at (512) 463-7319 (TxRRC).
6. File form in DOT files and retain for the life of the pipeline.
7. Retain Records for the Life of the Pipeline System



Operator Information	District/Division:		Date:	
	Operator Name:			
	Principal Address:			
	City:		State:	Zip:
Report Submitted Information	Person Making Report:			
	Job Title:		Telephone:	
	Date of Report:			
Condition Assessment Information	Person who determined condition exists:			
	Job Title:		Telephone:	
	Date condition was discovered:			
	Date condition was first determined to exist:			
Location and Description of Facility	<input type="checkbox"/> Onshore <input type="checkbox"/> Offshore <input type="checkbox"/> Inland Body of Water (Name):			
	Pipeline within Right-of-way of:			
	<input type="checkbox"/> Railroad <input type="checkbox"/> Paved Road/Street <input type="checkbox"/> Highway			
	Pipeline Station Number:			
	Pipeline System:		Location Code:	
	Street Address:			
	City:	County:	State:	
	Nearest Major Landmark:			
	Commodity Transported:			
	Type of Facility <input type="checkbox"/> Meter station <input type="checkbox"/> Mainline <input type="checkbox"/> Pump/Compressor Station <input type="checkbox"/> Pig Trap <input type="checkbox"/> Storage <input type="checkbox"/> Other; Describe:			
	Is system interstate? <input type="checkbox"/> Yes <input type="checkbox"/> No			
What was the activity leading to the discovery of the condition? <input type="checkbox"/> Routine Inspection <input type="checkbox"/> Construction Crossing <input type="checkbox"/> Operating Surveillance <input type="checkbox"/> Instrument Pig Survey <input type="checkbox"/> Maintenance Repair <input type="checkbox"/> Aerial Patrol <input type="checkbox"/> Third Party Report <input type="checkbox"/> Other; Describe:				
How was the condition verified? <input type="checkbox"/> Visual <input type="checkbox"/> Magnetic Particle NDT <input type="checkbox"/> Ultrasonic NDT <input type="checkbox"/> Radiographic NDT <input type="checkbox"/> Other; Describe:				



What was the cause of the condition? <input type="checkbox"/> Internal Corrosion <input type="checkbox"/> Excavation Damage <input type="checkbox"/> External Corrosion <input type="checkbox"/> Material Defect <input type="checkbox"/> Structural Support Failure <input type="checkbox"/> Localized <input type="checkbox"/> Construction Defect <input type="checkbox"/> Gasket/Seal/Packing Failure <input type="checkbox"/> General <input type="checkbox"/> Pressure Central Equipment Failure/Malfunction <input type="checkbox"/> Operator Failure <input type="checkbox"/> Other; Describe:		
Was the pipeline operated above the MAOP plus the allowable buildup? <input type="checkbox"/> Yes <input type="checkbox"/> No		
Did the condition cause a shutdown or at least 20% reduction in operating pressure? <input type="checkbox"/> Yes <input type="checkbox"/> No		
Was there a discharge? <input type="checkbox"/> Yes <input type="checkbox"/> No		
Additional Description/Cause/Effects on Safety:		
Nearby Facility Information	Is there a building intended for human occupancy within 200 yards? <input type="checkbox"/> No <input type="checkbox"/> Yes; Describe:	
	Is there an outdoor place of assembly within 200 yards? <input type="checkbox"/> No <input type="checkbox"/> Yes; Describe:	
Corrective Action Information	<input type="checkbox"/> Shutdown <input type="checkbox"/> Pressure Reduction <input type="checkbox"/> Repair	
	Describe Repairs:	
	Start Date:	Estimated Completion Date:
Form Was Electronically Sent To	<input type="checkbox"/> DOT <input type="checkbox"/> TRCC <input type="checkbox"/> Midland Home Office	
	Signature:	
	Date:	Time:
Further Proposed Actions:		
Supervisors' Signatures:		Date:
Completed By:		Date:



**When to Use
This Form**

This form is used in conjunction with procedure P-192.5 to document the review of class location of the pipeline.

**Reviewed
Procedures**

☐ P-192.5 *Class Location Survey and Determination*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Review the pipeline right-of-way to determine if there is a change in the class location per procedure P-192.5 and complete form.
2. Place in File 192.5. Retain for 2 years or until next review whichever is longer.



Survey Date:

Person Conducting Survey:

Pipeline System Name:

Odorization: Yes ☐ No ☐ (Class 3 & 4 location must have odorization unless exempt) If no, explain why:

Pipe Segment Location			Common Name for Segment	Classification (Refer to diagrams in procedure P-192.5 for determination of class locations.)	
Starts	Lat	Long		Class Location	HCA
Start					
End					
Start					
End					
Start					
End					
Start					
End					
Start					
End					
Start					
End					
Start					
End					

Completed by: _____ Date: _____

*If there is a change in class location from the prior year the MAOP determination form for this segment of pipe needs to be recalculated.



**When to Use
This Form**

This form is used in conjunction with procedure P-192.8 to document the determination of a pipeline.

**Reviewed
Procedures**

☐ P-192.8 *Determination of Gathering or Transmission or Distribution Pipelines*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Review the pipeline operations, specific pipe data (i.e., OD, MAOP, %SMYS, etc.), class location to determine if the required procedures and reporting process.
2. Place in compliance file for the system. Retain for the life of the pipeline.



District Name:		Pipeline System Name:	
Type of Product in the System:	Un-processed Natural Gas	Processed Natural Gas	
Pipe Material:	Size of Pipe (OD):		
MAOP:	%SYMS		
Class Location:	Date of the most recent Class Location Survey:		
Gathering System:	Transmission System:	Distribution System:	
If Gathering System: Type A Type B Type C Type R			
Specific Start Point		Specific End Point	
Completed by:			
Date:			



**When to Use
This Form**

This form should be used in conjunction with procedure P-192.14 anytime an existing pipeline is being brought into DOT jurisdiction.

**Reviewed
Procedures**

☐ P-192.14 *Conversion of Service*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Make a copy of this form and replace the original in the manual. Do not mark up the original copy of this form.
2. Gather data and complete form.
3. Determine MAOP of pipeline using form F-192.619.
4. If at this time tests or inspections conducted for the conversion expose buried/submerged pipe or the internal surface of the pipe see Procedures P-192.459 and P-192.475(b).
5. Have supervisor sign form.
6. Place form in DOT file.
7. Retain Records for the Life of the Pipeline System.



Previous Service:		New Service:					
Relief Valves	Tag		Station		Setpoint (PSIG)		Capacity
Pipe Data	From Station	To Station	Pipe Diameter	Wall Thickness	Type of Pipe	U.T. Reading	Pipe Pressure Rating
Components	Pressure Rating of Weakest Component: _____ PSIG						
	Location and Description of Weakest Component:						
Hydrostatic Testing	Date of Last Test: _____				New Pressure Test Required? <input type="checkbox"/> Yes <input type="checkbox"/> No		
	Test Pressure: _____ PSIG				If YES complete Form F-192.517 for the test)		
Summaries	Summarize Investigation tests performed as a part of the conversion service:						
	Summarize repairs, replacements, alterations made as a part of the conversion of service:						
Supervisor Signature: _____					Date: _____		
Completed by: _____					Date: _____		



**When to Use
This Form**

This Packet is to be used in conjunction with the procedures listed below whenever pipeline welding is performed.

**Reviewed
Procedures**

- | | |
|------------------------------------|--|
| <input type="checkbox"/> P-192.225 | <i>Pipeline Welding</i> |
| <input type="checkbox"/> P-192.241 | <i>Visual Inspection of Welds</i> |
| <input type="checkbox"/> P-192.243 | <i>Non Destructive Testing of Welds</i> |
| <input type="checkbox"/> P-192.245 | <i>Repair or Removal of Weld Defects</i> |

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each welding project.
 - a. The following steps refer to the *Daily Welding Inspection* section of this form:
 - b. Complete Description section of form.
 - c. Assign number to each weld and indicate approximate station.
 - d. Indicate welders' marks at welds.
 - e. Place and "X" in appropriate boxes to indicate which welder mark corresponds to which weld.
 - f. Complete NDT section for each tested weld.
 - g. For each weld tested, circle the corresponding "X".
 - h. Indicate total number of welds and total number of tested welds for each mark at the bottom of the column.
 - i. Perform the indicated calculations to obtain actual percentage of welds tested.
3. Attach maps identifying weld locations.
4. Place form in project file.
5. Retain Records for the Life of the Pipeline System.



General Information

System:	Segment:	Class Location:
<input type="checkbox"/> New Construction <input type="checkbox"/> Replacement	Drawing References:	
Contractor:	Date Started:	Date completed:

Were Company Welding procedures used? (49 CFR 192.225)

☐ Yes; Procedure Number:

Complete Welding Procedure Qualification Test section of this packet if a new procedure. If the procedure has already been qualified, where is the documentation of the test?

☐ No; Attach Contractor procedure and qualification documentation.

List welders and the location of there qualification documents: (49 CFR 192.227)

Welder Name	Location of Qualification Documentation	Date of Needed Re-qualification

List verification of inspector conducting visual inspection of weld: (49 CFR 192.241)

Method of Verification:

Signature of Inspector:

Signature of Person
Checking Qualification:

List verification of Non-destructive Testing Technician Qualification: (49 CFR 192.243)

Total Number of Girth Welds:

Number of Welds NDTed:

Number of Welds Failing Test:

Disposition of failed welds:

Note: Attach report from inspector. Ensure he uses a qualified procedure and provides a copy of the procedure and documentation that it was qualified. If this is not available, use the Radiographic Procedure Qualification portion of this packet to qualify the procedure. Also attached to this packet is a log for inspecting welds to be used if needed.

Signature of
Technician:


Signature of Person
Checking Qualification:




Welding Procedure Qualification Test (192.225)

General Data	Test date:		Location:	
	Joint Type: <input type="checkbox"/> V. Butt <input type="checkbox"/> Fillet <input type="checkbox"/> Nozzle <input type="checkbox"/> Groove <input type="checkbox"/>		Pipe Position: <input type="checkbox"/> Horizontal <input type="checkbox"/> Vertical	
	Weld repair <input type="checkbox"/> Other:			
	Nozzle Position: <input type="checkbox"/> Horizontal <input type="checkbox"/> Flat <input type="checkbox"/> Overhead		Welding Position: <input type="checkbox"/> Fixed <input type="checkbox"/> Roll	
		Line Up Clamps: <input type="checkbox"/> Internal <input type="checkbox"/> External <input type="checkbox"/> None		
When line-up clamp removed:			Cleaning Method:	
Test Material	Grade:		Type:	
	Wall: in.		Diameter: in.	
Thermal Data	Ambient: °F		Preheat: °F	
	Interpass: °F			
Preheat Method:				
Welding Data	Welding process:		Electrode Group:	
			Vertical Welding Direction: <input type="checkbox"/> Down <input type="checkbox"/> Up	
	Or Class:			
	Application:		Number of welders:	
	Shielding gas or flux:			
Machine Polarity:		Power Source:		



Qualification Scope	Diameter Group (O.D.- in.) <input type="checkbox"/> 2 3/8 to 12 3/4 <input type="checkbox"/> over 12 3/4		Wall Group (In.): <input type="checkbox"/> Less than 3/16 <input type="checkbox"/> 3/16 to 3/4 <input type="checkbox"/> Over 3/4		
	Electrode Group:	Vertical Welding Direction: <input type="checkbox"/> Down <input type="checkbox"/> Up		Min. Base Metal Temperature: °F	
	Or Class:				
	Material Grades:		Travel Speed change:	Increase: %	
				Decrease: %	
	Pipe or nozzle incline: ° to °		Maximum time lapse (Min.):	Between 1 st & 2 nd passes:	
				Between other passes:	
	Joint Type: <input type="checkbox"/> V. Butt <input type="checkbox"/> Fillet <input type="checkbox"/> Nozzle <input type="checkbox"/> Groove <input type="checkbox"/> Weld repair <input type="checkbox"/> Other:				
	Remarks:				
Engineering Certification:					
Management Approval:					
Joint Design Sketch: 					



Bead Sequence Sketch (if not shown above): 

(number in accordance with the following table)

Bead Number	Electrode	Size (in.)	Current (amps)	Voltage (volts)	Speed (in./min.)	Time Lapse Between Beads (min.)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

Test Results	Tensile Tests (psi)		Min:	Max:	Avg:
	Hardness Tests				
	Scale:		Min:	Max:	Avg:
	Code or Standard: <input type="checkbox"/> API <input type="checkbox"/> ASME	Tests Passed: <input type="checkbox"/> Tensile <input type="checkbox"/> Face bend <input type="checkbox"/> Side bend <input type="checkbox"/> Macro exam <input type="checkbox"/> Nick Break <input type="checkbox"/> Root bend <input type="checkbox"/> Hardness <input type="checkbox"/> Visual			
	Remarks:				
Company Inspector(s):					



Radiographic Procedure Qualification (192.243(a))

General	Contractor:		Location:		Date:	
	Lead Radiographer (Name):					
	Soc. Sec. No.:			SNT Qual. Level:		
	NDT Standard Followed: <input type="checkbox"/> API 1104 <input type="checkbox"/> ASTM 142 <input type="checkbox"/> ASME VIII <input type="checkbox"/> OTHER (Specify):					
Procedure Details	Object(s) Tested:			Pipe Contents:		
	<input type="checkbox"/> Butt Weld <input type="checkbox"/> Groove Weld <input type="checkbox"/> Fillet Weld <input type="checkbox"/> Branch Weld			<input type="checkbox"/> Empty <input type="checkbox"/> Liquid <input type="checkbox"/> Gas <input type="checkbox"/> Specify:		
	Radiation Source:		Radiation Strength		Radiation Location:	
	<input type="checkbox"/> X-ray <input type="checkbox"/> Iridium <input type="checkbox"/> Other (Specify):		Curies:		<input type="checkbox"/> External <input type="checkbox"/> Internal	
			kV:			
	Focal Spot Size (in.):	Source to object Distance (in.):	Object to film Distance (in.):	Distortion (in.):		
	Wall thickness (in.)	Pipe:	Branch:	Sleeve:		
	Diameter (in.)	Pipe:	Branch:	Radiation to Film Angle: °		
	Number of Exposures:		Filters	Type:	Location:	
			Screens	Type:	Location:	
	Thickness of Weld Radiographed (in.):	Steel Thickness Equivalence:		Exposure (Minimum) Time: hrs.		
	Film Type:	Manufacturers Designation:		Class Designation:		
	<input type="checkbox"/> Opaque <input type="checkbox"/> Transparent			<input type="checkbox"/> Class I <input type="checkbox"/> Class II <input type="checkbox"/> Class III <input type="checkbox"/> Class IV		
	Film Processing:		Processing	Temperature: °F		
<input type="checkbox"/> Manual <input type="checkbox"/> Automatic		Development: min.				
		Stop Bath: min.				
		Fixing: min.				
		Wash: min.				



Results	Density (H & D)	Min.:	Max.:
	Minimum Visible Pentrameter	Thickness:	Smallest Hole:
Qualification Scope	Object Tested: <input type="checkbox"/> Butt or Groove Weld <input type="checkbox"/> Fillet or Branch Weld		Pipe Contents: <input type="checkbox"/> Liquid <input type="checkbox"/> Gas <input type="checkbox"/> Specify:
	Radiation to film angle range From: To:	Diameter Range (in.) From: To:	Steel wall thickness (Equiv.) Range (in.) From: To:
	Comments:		
	Qualification Certification:		
	Management Approval:		



Visual Welding Inspection (192.241)

Description		From:						To:					
Percent of welds to be nondestructively tested: %								Comment:					
Percent of welders' welds to be nondestructively tested %								Comment:					
NO. GW¹	Weld Inspections												
	Approximate Station of Weld	Welder(s) mark(s) at weld						Weld Disposition			Comment(s)		
								Accept	Repair	Replace			
Welding inspector:						Approval:				Date of inspection:			

¹ Girth Weld



Daily Welding Inspection (192.243(f))

Description		From:						To:					
Percent of welds to be nondestructively tested: %								Comment:					
Percent of welders' welds to be nondestructively tested %								Comment:					
NO. GW²	Weld Inspections												
	Approximate Station of Weld	Welder(s) mark(s) at weld						Weld Disposition				Comment(s)	
							NDT	Accept	Repair	Replace			
(a) Total No. of X's circled							(y)	% Welds NDT = (y) / (z) x 100 = %					
(b) Total No. of G.W.							(z)	Weld pass Welder marks					
(a) / (b) x 100 = % of welder's welds nondestructively tested								Root (first) Hot (second) Filler & Cap Repairs					
Welding inspector:						Approval:						Date of inspection:	

² Girth Weld



**When to Use
This Form**

This form is to be used in conjunction with the procedures listed below whenever pipeline construction or replacement is undertaken.

**Reviewed
Procedures**

- | | |
|------------------------------------|--|
| <input type="checkbox"/> P-192.305 | <i>General Inspection</i> |
| <input type="checkbox"/> P-192.319 | <i>Installation of Pipe in a Ditch</i> |
| <input type="checkbox"/> P-192.325 | <i>Measure Underground Clearance</i> |

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each construction project.
3. Attach maps identifying each crossing of another pipeline, location of each buried utility crossing, location of each overhead crossing, each valve and corrosion test station.
4. Place form in project file.
5. Retain Records for the Life of the Pipeline System.



System:		Segment:	
Class Location:		Drawing References:	
<input type="checkbox"/> New Construction <input type="checkbox"/> Replacement			
Nominal O.D (in)		Wall thickness:	
Grade:	Pipe class:	Length:	ft.
Pipe Manufacturer:		Max. Operating Temp.: °F	
Manufacturing location:		Method of transportation:	
Year manufactured:		Year purchased:	
Yield Strength:	psi	Design Temp.:	°F
Internal Design Pressure:	psi	Test Pressure Factor:	
Seam Joint Factor:		ASME/ANSI Flange Rating:	#
Contractor:			
Date Started:		Date completed:	
Depth of cover:	in. (49 CFR 192.327)	Underground clearance:	in. (49 CFR 192.325)
List specifications/standards that the pipe and/or components were designed/constructed under. (49 CFR 192.303)			
List verification of Inspector Training / Qualification. (49 CFR 192.305)			
Signature of Inspector:			
Signature of Person Checking Qualification:			
Note: Attach a copy of the Inspector's Daily Reports to the project file.			
Completed by:			Date:



**When to Use
This Form**

This form is to be used in conjunction with the procedure P-192.455 whenever the cathodic protection system on the pipeline is installed or additional protection is added.

**Reviewed
Procedures**

☐ P-192.455 *Installation of Cathodic Protection System*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each construction project.
3. Attach maps identifying each corrosion test station.
4. Place form in project file.
5. Retain Records for the Life of the Pipeline System.

Cathodic Protection System Installation

Pipeline System:	Segment:
Drawing References:	Class Location:
<input type="checkbox"/> New Construction <input type="checkbox"/> Replacement	
Describe the type of Cathodic Protection Installed	
<input type="checkbox"/> External Coating	
Material:	Application Method:
<input type="checkbox"/> Anodes	
Date Installed:	Type of anodes:
Weight of Anodes:	Number of Anodes:
Spacing: ft	Depth: ft
Distance from Structure: ft	Resistivity of soil: OHM-cm
Estimated current output/anode: MA	Estimated Replacement Date:
<input type="checkbox"/> Rectifier	
Complete Cathodic Protection Rectifier and Ground Bed Data portion of this packet.	
<input type="checkbox"/> Map attached showing location of cathodic protection equipment.	
Completed by:	Date:



Rectifier Installation

This report covers: <input type="checkbox"/> New installation <input type="checkbox"/> Addition <input type="checkbox"/> Replacement					
Rectifier LOC No.			Drawing No.		
Station No.		Mile No.		Land Owner: Tenant:	
Size of Easement:			Survey or Section:		
Abstract No:			County:		
Rectifier Data	Type:		Model:		Serial No.
	Mfgr:		Supplier:		Order No.:
	A.C. Volts:		D.C. Rating: Volts Amps		Initial Readings: Volts Amps
Groundbed Data	Vertical	No. Rods:		Type:	Size:
		Hole Depth:		Hole Diameter:	Hole Spacing:
	Horiz- ontal	No. Rods		Type:	Size:
		Ditch Depth:		Length & size of scrap pipe:	
	Distance to Line:			Backfill (type and amount):	



Cable Data	Size	Length	Type	Insulation	
Ground bed header cable					
Ground bed to rectifier					
Pipe line to rectifier					
Ground rod lead					
CONNECTION: Ground rod lead to header wire					
Power Source:		Meter No.:		Kh:	
Rate:	Avg. Monthly Bill:		Installation Cost:		
AFE No.:	Installed by (Or contractor):			Date:	
Soil Resistivity At Depths	Date	2 1/2'	5'	10'	20'
Approved by:				Date:	
Completed by:				Date:	

NOTE: Attach sketch of Installation on separate sheet



**When to Use
This Form**

This form is to be used to properly document corrective actions taken when cathodic deficiencies are discovered.

**Reviewed
Procedures**

- ☐ P-192.459 External Examination of Exposed Pipe
- ☐ P-192.465(b) Inspect/Test/Repair Rectifier
- ☐ P-192.465(c) Inspect Reverse Current Switches, Diodes and Interference Bonds

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-192.459.
2. Complete investigation and remediation.
3. Investigation and remediation must be documented using F-192.465(d).
4. Retain Records for the Life of the Pipeline System



District: _____

Pipeline/System Name: _____

Date of Discovery: _____

Location: _____

Type of Line: ☐ Transmission ☐ Distribution ☐ Gathering

Class Location: 1 2 3 4

Business District: Yes No

Will this affect the integrity of the pipeline: Yes No

If yes, please complete Form WTG-AOC in addition to this Form

Description of why remedial action is needed:

Remedial Actions Taken: (please log all actions taken and dates of completion)

Were Remedial Actions Taken Successful: ☐ Yes ☐ No

If No, please comment:

Remedial Actions Completed By: _____

Preparer's signature: _____

Date: _____

Supervisor signature: _____

Date: _____



**When to Use
This Form**

This form is used to document the re-evaluation of pipelines that are not cathodically protected to determine if they need cathodic protection.

**Reviewed
Procedures**

- ☐ P-192.455 *Installation of Cathodic Protection System*
☐ P-192.465(e) *Re-evaluation of Non-protected Pipe*
☐ P-192.483 *Cathodic Protection Remediation*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Refer to Corrosion Control Procedures in the O&M Manual to ensure inspections are done correctly.
3. Gather data and complete form.
4. If corrosion is found or there is a suspected need for remediation, document below and forward this document to the Corrosion Control Engineer for immediate review.
5. Place completed form in file.
6. Retain Records for the Life of the Pipeline System.



Follow-up Items

Note items that require immediate remedial action.

Action Item (Problem)	Action Taken	Date	Signed



Pipe System:	Location:
Commodity(s) Transported:	
Is an electrical survey practical for this line segment, to determine if active corrosion is present? <input type="checkbox"/> Yes <input type="checkbox"/> No	
If YES, conduct the electrical survey and attach the results to this form.	
If NO, do one or more of the following: <input type="checkbox"/> Evaluate corrosion records <input type="checkbox"/> Evaluate leak history records <input type="checkbox"/> Perform other appropriate evaluations to identify active corrosion <input type="checkbox"/> Leakage Survey	
Do any of the above evaluations indicate that active corrosion is present for this line segment? <input type="checkbox"/> Yes <input type="checkbox"/> No	
If YES, cathodically protect the pipeline segment as required by 49 CFR § 192.452.	
If NO, schedule another evaluation using this form in 5 years.	
Completed by:	Date:
Supervisor's Signature:	



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**When to Use
This Form**

This form is used to document internal corrosion control monitoring.

**Reviewed
Procedures**

☐ P-192.477 *Monitor Internal Corrosion*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Refer to corrosion control procedures to ensure inspections are done correctly.
3. Gather data and complete form. Each section is for one inspection of one coupon.
4. If corrosion is found or there is a suspected need for remediation, document in the *Follow-Up Items* section and forward this document to the Corrosion Control Engineer for immediate review.
5. Place completed form in file.
6. Retain Records for the Life of the Pipeline System.



Follow-up Items

Note items that require immediate remedial action.

Action Item (Problem)	Action Taken	Date	Signed



Coupon Information	Coupon ID#	
	Installation Date:	Removal Date:
	Initial Weight:	Final Weight:
	Corrosion rate: (mpy)	
Did coupon have: <input type="checkbox"/> Slime <input type="checkbox"/> Light pitting <input type="checkbox"/> Heavy pitting <input type="checkbox"/> No corrosion <input type="checkbox"/> Other (describe):		
Completed by:		Date:

Coupon Information	Coupon ID#	
	Installation Date:	Removal Date:
	Initial Weight:	Final Weight:
	Corrosion rate: (mpy)	
Did coupon have: <input type="checkbox"/> Slime <input type="checkbox"/> Light pitting <input type="checkbox"/> Heavy pitting <input type="checkbox"/> No corrosion <input type="checkbox"/> Other (describe):		
Completed by:		Date:

Coupon Information	Coupon ID#	
	Installation Date:	Removal Date:
	Initial Weight:	Final Weight:
	Corrosion rate: (mpy)	
Did coupon have: <input type="checkbox"/> Slime <input type="checkbox"/> Light pitting <input type="checkbox"/> Heavy pitting <input type="checkbox"/> No corrosion <input type="checkbox"/> Other (describe):		
Completed by:		Date:



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**When to Use
This Form**

This Packet is to be used in conjunction with procedure P-192.513 whenever testing of plastic pipe is performed.

**Reviewed
Procedures**

☐ P-192.513 *Plastic Pipe Pressure Test Requirements*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Complete all sections of the form.
3. Document any repairs required due to rupture or leak using packet F-192.305.
4. Attach pressure recording charts, test instrument calibration data.
5. For unsuccessful tests complete *Unsuccessful Hydrostatic Test* section of this form.
6. Have test supervisor sign form.
7. Send a copy of the form to engineer to establish MAOP of the pipeline. See Form F-192.619.
8. Place in DOT file.
9. Retain Most Current Copy or for 5 Years Whichever is Longer.



System		Date	
Location of Line			
Length of Line:		Size of Pipe:	Type of Pipe:
Test Medium: <input type="checkbox"/> Air <input type="checkbox"/> Nitrogen <input type="checkbox"/> Water <input type="checkbox"/> Natural Gas <input type="checkbox"/> Other:_____			
Time Test started: _____ am / pm		Time test complete: _____ am / pm	
Test Start	Pressure	Temperature	Elevation
Test Stop	Pressure	Temperature	Elevation
Purpose: <input type="checkbox"/> Initial Construction <input type="checkbox"/> Pretest <input type="checkbox"/> Retest <input type="checkbox"/> Repair or replacement			
Explanation of pressure gain / Loss			
Person Making Test:		Date:	



**When to Use
This Form**

This Packet is to be used in conjunction with procedure P-192.501

**Reviewed
Procedures**

☐ P-192.501 *Steel Pipeline Pressure Test Requirements*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Complete all sections of the form.
3. If the pipeline is exposed for any reason (external or internal) complete Form WTG 1100.
4. Document any repairs required due to rupture or leak using packet F-192.305.
5. Attach pressure recording charts, test instrument calibration data.
6. For unsuccessful tests complete *Unsuccessful Hydrostatic Test* section of this form.
7. Have test supervisor sign form.
8. Send a copy of the form to engineer to establish MAOP of the pipeline. See Form F-192.619.
9. Place in DOT file. Keep most current test.
10. Retain Records for the Life of the Pipeline System.



Description

Name of Individual Responsible for Testing:			
Operator:			
System or Facility Tested:	Start Date:		Start Time:
	Stop Date:		Stop Time:
Extent of Test: From Station:		To Station:	
Test Medium: <input type="checkbox"/> Water <input type="checkbox"/> Other: _____			Inhibitor: <input type="checkbox"/> Yes <input type="checkbox"/> No
Test Company:	Inhibitor Type:	Inhibitor Rate:	
Purpose: <input type="checkbox"/> Initial Construction <input type="checkbox"/> Pretest <input type="checkbox"/> Retest <input type="checkbox"/> Repair or replacement			
Source of Water Fill:			
Leak Detection Material Type:			Rate:
Pressure Pump Location:	Sta:	MP:	Elev.:
Certified Gauge Location:	Sta:	MP:	Elev.:
Certified Gauge Calibration Date:		Serial Number:	
Pressure Recorder Serial Number:			
Pipe Temp. Recorder Serial Number:			
Elevation and Calculated Pressure and Critical Points During Test Period:			
High Point:	Elev:	Press. Min:	Press. Max:
Low Point:	Elev:	Press. Min:	Press. Max:
Certified Gauge:	Elev:	Press. Min:	Press. Max:



Pipe Data

From Sta. No. to Sta. No.	OD (inches)	Wall (inches)	Grade	SMYS	Seam FAC "E"	Design FAC "F"	Internal Design Press.

Component Data

Description	Manufacturer	SMYS	MAOP/MOP
Weakest Component other than Pipe:			
MAOP/MOP of Weakest Component:			



Pressure and Temperature Data

No	Time	Gauge Press	Chart Press	Pipe Temp	Ambient	Remarks
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						



Summary of Test

Test Medium:	Min. Test Pressure:
Test Duration:	Test pressure (Corrected for high elevation):
<input type="checkbox"/> Piping was buried during test <input type="checkbox"/> Piping was exposed & inspected during test	
Test Supervised by:	
Certified by Division or Project Engineer:	
Approved by Division or Project Manager:	
Documents Attached: <input type="checkbox"/> Pressure Chart <input type="checkbox"/> Temp. Chart <input type="checkbox"/> Sketch or Diagram <input type="checkbox"/> Profile (required if elevation change is > 100')	

Unsuccessful Hydrostatic Test

Pipeline/Line Section:				
Pipe Data:	O.D.:	W.T.:	Grade:	Year Built:
Seam Type: <input type="checkbox"/> SMLS <input type="checkbox"/> ERW <input type="checkbox"/> SAW <input type="checkbox"/> Spiral <input type="checkbox"/> Flash Weld <input type="checkbox"/> Lap Weld				
Internal Pressure at 100% SYMS:				
Joint Type: <input type="checkbox"/> Acetylene <input type="checkbox"/> Arc Weld <input type="checkbox"/> Mechanical				
Pipe Manufacturer:				
Design Test Pressure Max:			Min:	
Test Section Number:	From Sta.:	(MP:)	To Sta.:	(MP:)
Reason for Unsuccessful test: <input type="checkbox"/> Leak <input type="checkbox"/> Rupture				
Metallurgical Report Review: <input type="checkbox"/> Yes <input type="checkbox"/> No				



Leak Data

Was leak found?

<input type="checkbox"/> Yes	Date:	Time:	Station:	Elevation:
	Time on Test when leak was found:			
	Leakage Rate:			
	Pressure at leak when discovered:			
	Location: <input type="checkbox"/> Body <input type="checkbox"/> Seam			

☐ No

Description and possible causes of leak:

Rupture Data

Location:	Station:	Elevation:
Date of rupture:		Time of Rupture
Pressure at rupture:		Time on Test before rupture:
Location: <input type="checkbox"/> Body <input type="checkbox"/> Seam		

Description and possible causes of rupture:



**When to Use
This Form**

This form is used in conjunction with procedure P-192.605(a) to document the annual review of the DOT Operations and Maintenance Manual.

**Reviewed
Procedures**

☐ P-192.605(a) *Operations and Maintenance Annual Review*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Review the Operations and Maintenance Manual and make any necessary changes. This review should also include review of any abnormal operating condition or emergency procedure review documentation. This review should follow P-192.605(a)
2. Ensure all needed changes are made to the Operations and Maintenance Manual.
3. Place in file 192.605(a). Retain Records for 2 years or until next review whichever is longer.



Manual Section	Changes Needed?		Date Review Completed	Signature
	No	Yes (list changes)		
Completed by			Date	



**When to Use
This Form**

This form is used in conjunction with procedure P-192.605(b)(8) to document the Review of Operator Personnel.

**Reviewed
Procedures**

☐ P-192.605(b)(8) *Review of Work Done by Operator*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Review work performed by operator personnel to determine the adequacy of the procedures being used.
2. Document the review on this form.
3. Send a copy of this form showing the needed revisions to the O&M Manual to the Manual Coordinator.
4. Place in file 192.605(b)(8). Retain Records for 2 years or until next review whichever is longer.



Procedure Reviewed:

Are the procedures effective and adequate for the task being performed?

☐ Yes

☐ No; Explain:

Are suggested changes needed to the current procedure based on review?

☐ No

☐ Yes; list required revisions below:

Suggested Revision:

Review Completed by:

Date:

Received By:

Date:

Action Taken by WTG Compliance Department:



**When to Use
This Form**

This form should be used anytime there is an abnormal operating condition involving the pipeline and/or facility per procedure P- 192.605 (c)(1).

**Reviewed
Procedures**

☐ P-192.605(c) *Handling Abnormal Conditions*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Complete this form. Refer to procedure P-192.605(c).
2. Send suggested procedure revisions to the WTG Compliance Department.
3. Place record in File 192.605(c). Retain Records for 5 years.



Type of Abnormal Operations:	
<input type="checkbox"/> Unintended closure of valves	<input type="checkbox"/> Loss of communications of normal operations which cannot be verified by other means
<input type="checkbox"/> Increase in pressure	<input type="checkbox"/> Decrease in pressure
<input type="checkbox"/> Activation of a safety device	<input type="checkbox"/> Flow rate outside of normal operating limit
<input type="checkbox"/> Other:	
How was notification of the abnormal procedure received?	
What actions were taken to correct the condition?	
Were there any problems when returning to normal operations? If so, what were they and how were they handled?	
Did the operations personnel follow procedures for this abnormal operation?	
<input type="checkbox"/> Yes	
<input type="checkbox"/> No; Explain:	
Do the procedures adequately address this abnormal operation?	
<input type="checkbox"/> Yes	
<input type="checkbox"/> No; list required revisions below:	



Procedure	Revision Needed
Completed by: _____ Date: _____	
Approved by: _____ Date: _____	



**When to Use
This Form**

This form is to be used to properly document the inspection and investigation of any findings on the pipeline Right of Way following an extreme weather condition or natural disaster.

**Reviewed
Procedures**

☐ P-192.613 *Continuing Surveillance - Including extreme weather or natural disaster*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-192.613.



If surveillance can not be done within 72 hours of event, notify the compliance department.
Compliance will notify appropriate PHMSA region director

Date _____ Time of Event _____ AM PM

Extreme Weather or Natural Disaster _____ Any Further Action Needed _____

District _____ System _____

Applicable Forms during Surveillance (Forms to be kept for Life of Pipeline)

WTG-1103 Patrolling:

Date Completed _____ Time Completed _____ AM PM

F-192.706 Leak Survey:

Date Completed _____ Time Completed _____ AM PM

Provide Details below if Earthquake and send this form to Compliance Dept:

Date Completed _____ Time Completed _____ AM PM

Epicenter Location lat/long: _____

Employees Assigned: _____

Findings: _____

Actions Required: _____

Employee Assigned to Follow-up if Required: _____

Completed By _____ Date _____



**When to Use
This Form**

These forms should be completed when third party excavation is occurring in the vicinity of the pipeline. Also included is the documentation of foreign lines.

**Reviewed
Procedures**

- ☐ P-192.614 *Damage Prevention Program*
☐ P-192.615(c) *Liaison with Public Officials*
☐ P-192.616 *Public Education*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Refer to Procedure P-192.614.
2. Receive notice of proposed excavation and record relevant data from the excavator on this form. If a fax is received from the One Call Center, attach to this form.
3. Determine if the proposed excavation is in the vicinity of the pipeline.
4. Make proper notification.
5. Use page 2 of this form to document periodic (frequency depending on actual danger to the pipeline) right-of-way inspection during excavation. When the project is complete, there may be multiples of this inspection to add to the packet.
6. Have Company Representative present when excavation is directly on the pipeline. Complete appropriate section of this form.
7. If our pipeline is to be encroached upon, fill out that section of this form. Forward this information to mapping so they can update the pipeline map.
8. If our pipeline is exposed complete Form WTG 1100.
9. Place form in File 192.614. Retain Records for life of pipeline if a crossing of our line was done. In all other cases retain for 5 years.



Excavator Information

Company Name:	Contact Name:
Phone (office):	Phone (mobile):
Date of excavation:	Locate Number:
Description of planned work:	
<p>Could this affect the safety of our pipeline? <input type="checkbox"/>YES <input type="checkbox"/>NO</p> <p>If YES, complete the remainder of this form and follow procedure P-192.614 to properly mark the pipeline. Notify the excavator when the line has been marked.</p> <p>If NO, let the excavator know that we have no lines that can be affected. However, ensure the excavator understands where our nearest line is and request that they call us if they get close to it.</p>	

Company Representative Certification

Name:	Title:
Phone (office):	Phone (mobile):
Date of excavation:	Locate Number:
Description of planned work:	
<p>Was pipeline exposed? <input type="checkbox"/>YES <input type="checkbox"/>NO</p> <p>If YES, complete Form WTG 1100.</p>	
Signature of Company Representative:	Date:



Right-of-Way Inspection During Excavation

Date of inspection:		Inspection #:	
Performed By	<input type="checkbox"/> Company		
	<input type="checkbox"/> Third party (complete contact information below)		
	Company name:		
	Contact:	Phone:	
	Address:		
Type	<input type="checkbox"/> Excavation <input type="checkbox"/> Tunneling <input type="checkbox"/> Blasting <input type="checkbox"/> Backfilling <input type="checkbox"/> Boring		
	<input type="checkbox"/> Removal of above ground structures <input type="checkbox"/> Other earth moving operation Note: If done by blasting, a leakage survey is required.		
Is there any evidence of damage or leaks? <input type="checkbox"/> No <input type="checkbox"/> Yes If YES , explain:			
Other relevant information:			
Completed by:		Date:	

Encroachments

County:	State:	Town:
---------	--------	-------



Date:	Time:	Drawing no.:	Line list no.:
Line name:	Mile post:	Drawing station plus:	
Name and title of caller:			Caller phone:
Date work is to start:		Time work is to start:	
Name and address of company:	Field contact person	R.O.W. affected? <input type="checkbox"/> Yes <input type="checkbox"/> No	
	Field phone no.	Explosives used? <input type="checkbox"/> Yes <input type="checkbox"/> No	
Description of proposed excavation, encroachment, or foreign crossing:			
Encroachment or Foreign Crossing: <input type="checkbox"/> Proposed <input type="checkbox"/> In progress <input type="checkbox"/> Completed <input type="checkbox"/> Stopped			
Notice given? <input type="checkbox"/> Yes <input type="checkbox"/> No			
Pipeline marked through encroachment area? <input type="checkbox"/> Yes <input type="checkbox"/> No			
Width of R.O.W.:			
Limits of R.O.W. marked? <input type="checkbox"/> Yes <input type="checkbox"/> No If NO, explain:			
Will staking and marking be done before starting date? <input type="checkbox"/> Yes <input type="checkbox"/> No If NO, explain:			
Property owner:			Phone:
Address:			



Date of initial report:				Date of revised report:							
Date of foreign crossing:			Observed by:		Observed date:						
Our lines exposed? <input type="checkbox"/> Yes <input type="checkbox"/> No				Date exposed:							
Pipeline surveillance report required? <input type="checkbox"/> Yes <input type="checkbox"/> No If no, explain:						Completed? <input type="checkbox"/> Yes <input type="checkbox"/> No					
Foreign Crossing	<input type="checkbox"/> Tel. cable <input type="checkbox"/> Elec. cable <input type="checkbox"/> Other:			<input type="checkbox"/> Gas <input type="checkbox"/> Oil <input type="checkbox"/> Other: Pipeline size O.D.:							
	Pipe material:		Kind of coating:		Wrapper:						
	Distance in inches from top of pipe to ground level			Measured clearance between lines:							
Our pipe: in. Foreign pipe or cable: in.											
Test Leads Installed	Our Line	Wire size:		Color:		Foreign line	Wire size:		Color:		
		Local CP potential: volts					Local CP potential: volts				
Remarks (other steps taken to protect the pipeline(s) and preserve the easement; other information helpful in controlling the encroachment):											



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**When to Use
This Form**

This form is used to document notifications of emergencies and emergency procedure review. It should be used in conjunction with the Emergency Plan and also procedure P-192.615.

**Reviewed
Procedures**

- ☐ P-191.5 *Reporting Incidents*
☐ P-191.23 *Reporting Safety-Related Conditions*
☐ P-192.615 *Emergency Response*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Document initial call. Refer to procedure P-192.615.
2. Document calls to fire, police and governmental agencies.
3. After the emergency is complete, review the procedures used to determine their effectiveness. Let DOT Coordinator know of procedural changes that need to be made.
4. Place original in File 192.615. Retain Records for 3 years.
5. Refer to Procedure P-191.5 to determine if this emergency constitutes a reportable accident or P-191.23 to determine if it is a safety-related condition. If so complete F-191.1 or F-191.25 respectively.



Receiving a Call Reporting a Potential Emergency

Caller Info.	Name:	Phone:
	Address	
Describe the emergency:		
Distance to nearest structure:		
Are there injuries? <input type="checkbox"/> No <input type="checkbox"/> Yes If YES, what type?		
Location of the emergency:		
Nearest town:		
Weather	Wind Direction From: To:	Wind Speed:
	<input type="checkbox"/> Fog <input type="checkbox"/> Rain <input type="checkbox"/> Snow <input type="checkbox"/> Other:	
Does this situation require immediate response? (Determined by Operator Personnel) <input type="checkbox"/> No <input type="checkbox"/> Yes--By Whom?		
Action	Dispatched To:	Time:
	Relayed To:	Time:
	Referred To:	Time:
Call Taken By:		Date: Time:



External Notifications

Agency/Organization Name	Phone	Called by	Date/Time	Comments



Procedure Review

Type of Emergency:	Date of Emergency:
Did the operations personnel follow written procedures for this emergency? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
Was emergency training provided adequate in handling the emergency? <input type="checkbox"/> Yes <input type="checkbox"/> No; Explain:	
Do the written procedures adequately address this abnormal operation? <input type="checkbox"/> Yes <input type="checkbox"/> No; list required revisions below:	

Procedure	Revision Needed

Review Completed by:	Date:
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**When to Use
This Form**

This form is used in conjunction with procedure P-192.615(c) to document liaison with public officials.

**Reviewed
Procedures**

☐ P-192.615(c)

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Conduct liaison with public officials per procedure P-192.615(c) and complete this form.
2. Place in File 192.615(c). Retain Records for 2 years or until next review whichever is longer. Investigation must be documented using F-192.615(c).



PUBLIC AGENCY INFORMATION

PART A

NAME: _____ I _____
(PLEASE PRINT)

Acknowledge receipt of :
Emergency Response Manual

On this _____ day of _____, 20_____.

Part B

EMERGENCY

Emergency Telephone: _____ Alternate Telephone _____
Department: _____ Contact Person / Ext.: _____

Geographical Area of Response Capabilities: _____

Part C

EMERGENCY RESPONSE CAPABILITIES

	YES	NO
1. Can assist or has plan for public evacuation.	<input type="checkbox"/>	<input type="checkbox"/>
2. Can provide medical assistance.	<input type="checkbox"/>	<input type="checkbox"/>
3. Can provide air evacuation services.	<input type="checkbox"/>	<input type="checkbox"/>
4. Can provide ambulance services.	<input type="checkbox"/>	<input type="checkbox"/>
5. Utilizes radio network.	<input type="checkbox"/>	<input type="checkbox"/>
6. Can assist in directing traffic on state and interstate highways.	<input type="checkbox"/>	<input type="checkbox"/>
7. Has firefighting equipment suitable for oil, gas and liquid petroleum fires.	<input type="checkbox"/>	<input type="checkbox"/>
8. Has firefighting equipment suitable for other types of fires.	<input type="checkbox"/>	<input type="checkbox"/>
9. Personnel are trained in fighting oil, gas and liquid petroleum fires.	<input type="checkbox"/>	<input type="checkbox"/>
10. Personnel are HAZMAT/HAZWOPER trained.	<input type="checkbox"/>	<input type="checkbox"/>
11. Has earth moving equipment suitable for working with spill containment that could be mobilized to the site of a spill.	<input type="checkbox"/>	<input type="checkbox"/>
12. Has a hazardous materials spill contingency plan.	<input type="checkbox"/>	<input type="checkbox"/>
13. Is familiar with the One-Call System.	<input type="checkbox"/>	<input type="checkbox"/>

Remarks:

Complete XLS form from web



Form F-192.619
Poly Pipe MAOP Determination
Revision January 2022

System Information

Company:		District:	
Pipeline System :		Class Location:	
Segment:		GPS Coordinates:	Start: End:
Pipe Material:	System MAOP: 0.00	Nominal O.D. (in.):	
Wall Thickness:		Pipe Grade:	
Pipe Class:		Length (ft.):	
Pipe Manufacturer:		Max. Operating Temp. (°F):	
Year Manufactured:	Year Purchased:	Test Pressure after Construction:	
Thermoplastic Pipe Value (psi):		Test Press. Factor:	1.5
Internal Design Press. (psi):		ASME/ANSI Flange Rating:	
Seam Joint Factor:		SDR Value:	Design Factor:
List specifications/standards that the pipe and/or components were designed/constructed under. (49 CFR 192.303):			
Comments:			
Determination Factor: (a)(1) (a)(2) (a)(3) or (a)(4)			
* If (a)(4) was selected, why?		Explain:	
Signature:		Date:	



Form F-192.619
Poly Pipe MAOP Determination

MAOP Calculation

1. Results of Design Pressure calculations, Step 10. (See attached Worksheet) (a)(1)		psi.
3. Flange Pressure Rating. (a)(1)		psi.
4. Flanged Valve Pressure Rating. (a)(1)		psi.
5. Design Pressure of any other component if less than flange or valve rating. (a)(1)		psi.
5.(a) Description of component entered on line 5. Relief valve, regulator, etc		
2. Results of Test Pressure calculations, Step 3. (See attached Worksheet) (a)(2)		psi.
8. Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the last 5 years preceeding the applicable date in the second column of the table listed in Procedure P-192.619. If this applies enter the appropriate pressure here. (a)(3)		psi.
7. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion, and the actual operating pressure. (a)(4) * Note: Over-Pressure protective devices must be installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded in accordance with 49 CFR 192.195.		psi.
10. The Pipeline MAOP is the lowest of steps 1-8 above, or the pressure from step 9 above. MAOP =	0.00	psi.
Note: If the MAOP is being re-calculated due to a change in class location, refer to Form F-192.611. Note: Any flanged or steel fitting used will have a higher pressure rating than PE pipe. Note: Additional requirements apply to distribution systems. See 49 CFR 192.621 and 192.623, if necessary.		



Design Pressure Calculations Worksheet (49 CFR 192.121)

1. Thermoplastic Pipe Value (S)

The hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2008, HDB/PDB/SDB/MRS Policies (incorporated by reference, see § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kpa).

[Note: Arithmetic interpolation is not allowed for PA-11 pipe]

Pipe Grade	Design Temp (°F)			
	73	100	120	140
2306	1250	1250	1000	800
2406	1250	1250	1000	800
3406	1250	1250	1000	800
3408	1600	1250	1000	800
4710	1600	1250	1000	800

Highlighter the criteria used above to determine the thermoplastic pipe value, and enter here.

S=

psi.

2. Nominal Wall Thickness (t) (49 CFR 192.109)

This is the nominal wall thickness of the pipe in inches, as described in the applicable pipe specification.

a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to a minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

Note: Additional wall thickness required for concurrent external loads in accordance with 49 CFR 192.103 may not be included in computing design pressure.

Circle the criteria used above to determine the Nominal Wall Thickness, and enter here.

t=

in.



3. Standard Dimension Ratio (SDR)

Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standard Institute preferred number series 10.

PE Pipe - Minimum Wall Thickness and SDR Values

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
1/2 CTS	0.09	7
1/2 IPS	0.09	9.3
3/4 CTS	0.09	9.7
3/4 IPS	0.095	11
1 CTS	0.099	11
1 IPS	0.119	11
1 1/4 IPS	0.151	11
1 1/2 IPS	0.173	11
2	0.216	11
3	0.259	13.5
4	0.265	17
6	0.315	21
8	0.411	21
10	0.512	21
12	0.607	21
16	0.762	21
18	0.857	21
20	0.952	21
22	1.048	21
24	1.143	21

* Copper Tubing Size (CTS) Iron Pipe Size (IPS)

Highlight the criteria used above to determine the SDR value, and enter here.

SDR =



4. Design Factor (DF)

DF = 0.32 or

PE pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided one of the following requirements are met:

- 1) The design pressure does not exceed 125 psig;
- 2) The material designation code is PE2708 or PE4710;
- 3) The pipe has a nominal size (IPS or CTS) of 24 inches or
- 4) The wall thickness for a given outside diameter is not less than that listed in the table listed in 3. Standard Dimension Ratio (SDR)

For Polyamide (PA-11) and Polyamide (PA-12) reference CRF 129.121 (d) & (e)

Highlight the Criteria used above to determine the Design Factor, and Enter here.

DF=

--



5. Nominal Outside Diameter (D)		
Enter the Nominal Outside Diameter of the pipe in inches here.	D=	
6. Design Pressure - Nominal (P)		
Use the results of steps 1-5 above in the following formula to calculate the nominal design pressure.		
$P = \frac{2 * S * t * DF}{D - t}$		
P= 2 * - *	P=	



Form F-192.619
Poly Pipe MAOP Determination

Test Pressure Calculation Worksheet

1. Test Pressure after construction		psi.
2. Test Derating Factor Plastic Pipe = 1.5		
3. MAOP Limited by Test Pressure Line 1 divided by Line 2		psi.



Operating Pressures for Flanged Valves (if applicale)			
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressure	
		Shell	Seat

Operating and Pressures for Flanges (if applicale)		
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressures

Pressure test calcaultion results		Design Pressure Results	
Is Any Component being Installed that has a lower MAOP than row 192 other than a flange or flanged valve?			
Description of Component	ANSI Class	Maximum operating Pressure	

Temporary Piping Blinds Blind Thickness (Inches) for Flange Sizes * Blinds Cut from ASTM A36 Carbon Steel Plate for Maximum Actual Hydrostatic Pressure as Given						
Nominal Pipe Size	ANSI 150	ANSI 300	ANSI 600	ANSI 900	ANSI 1500	ANSI 2500
	285 psig	740 psig	1480 psig	2220 psig	2500 psig	3000 psig



Complete XLS form from web



Form F-192.619

MAOP Determination
Revision January 2022

System Information

Company:		District:	
Pipeline System :		Class Location:	
Segment:		GPS Coordinates:	Start: End:
Pipe Material:	System MAOP:	Nominal O.D. (in.):	
Wall Thickness:		Pipe Grade:	
Pipe Class:		Length (ft.):	
Pipe Manufacturer:		Max. Operating Temp. (°F):	
Year Manufactured:		Year Purchased:	
Yield Strength:		Design Temp:	
Internal Design Press. (psi.):		Test Press. Factor:	
Seam Joint Factor:		ASME/ANSI Flange Rating:	
List specifications/standards that the pipe and/or components were designed/constructed under. (49 CFR 192.303):			
Comments:			
Determination Factor: (a)(1) (a)(2) (a)(3) or (a)(4)			
* If (a)(4) was selected, why?		Explain:	
Is this pipeline <u>In Line Inspectable</u> (ILI Capable)?			
Signature:		Date:	

***NOTE* If MAOP Changes, The Percent of SMYS Needs to be Reevaluated!**



Form F-192.619

MAOP Determination

MAOP Calculation

1. Results of Design Pressure calculations, Step 10. (See attached Worksheet) (a)(1)		psi.
3. Flange Pressure Rating. (a)(1)		psi.
4. Flanged Valve Pressure Rating. (a)(1)		psi.
5. Design Pressure of any other component if less than flange or valve rating. (a)(1)		psi.
5.(a) Description of component entered on line 5. Relief valve, regulator, etc		
2. Results of Test Pressure calculations, Step 3. (See attached Worksheet) (a)(2)	N/A	psi.
8. Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the last 5 years preceeding the applicable date in the second column of the table listed in Procedure P-192.619. If this applies enter the appropriate pressure here. (a)(3)		psi.
7. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion, and the actual operating pressure. (a)(4) * Note: Over-Pressure protective devices must be installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded in accordance with 49 CFR 192.195.		psi.
10. The Pipeline MAOP is the lowest of steps 1-8 above, or the pressure from step 9 above. MAOP =		psi.
<p>Note: If the MAOP is being re-calculated due to a change in class location, refer to Form F-192.611.</p> <p>Note: Additional requirements apply to distribution systems. See 49 CFR 192.621 and 192.623, if necessary.</p>		



Form F-192.619

MAOP Determination

Design Pressure Calculations Worksheet (49 CFR 192.105)

Note: Steel pipe in pipelines that have been converted under 49 CFR 192.14 or updated under Subpart K and have any variable necessary to determine the design pressure unknown, one of the following pressures is to be used as the design pressure:

- 80% of the first test pressure that produces yield under Section N5 of Appendix N of ASME B31.8, reduced by the appropriate factor in the table on the Test Pressure Calculation Worksheet; or
- If the pipe is 12 3/4 inches or less in diameter and is not tested to yield, 200 psi.

1. Yield Strength (S) (49 CFR 192.107)

a) For the pipe that is manufactured in accordance with a specification listed in section I of appendix B of 49 CFR Part 192, the yield strength to be used in the design formula is the SMYS stated in the listed specification, if that value is known.

b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix b of 49 CFR Part 192, or whose specification or tensile properties are unknown, the yield strength to be used in the design formula is one of the following:

- (1) If the pipe is tensile tested in accordance with section II-D of appendix B of 49 CFR Part 192, the lower of the following:
 - (i) 80 percent of the average yield strength determined by the tensile tests.
 - (ii) The lowest yield strength determined by the tensile tests.
- (2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 psi.

Circle the criteria used above to determine the pipe yield strength, and enter here.

psi.

2. Nominal Wall Thickness (t) (49 CFR 192.109)

This is the nominal wall thickness of the pipe in inches, as described in the applicable pipe specification.

a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to a minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

Note: Additional wall thickness required for concurrent external loads in accordance with 49 CFR 192.103 may not be included in computing design pressure.

Circle the criteria used above to determine the Nominal Wall Thickness, and enter here.

t=

in.



3. Design Factor (F) (49 CFR 192.111)

a) Except as otherwise provided in paragraphs (b), (c) or (d) below, the design factor to be used in the design formula is determined in accordance with the following table:

Class Location	Design Factor (F)
1	0.72
2	0.6
3	0.5
4	0.4

**Before choosing design pressure,
be sure and review b), c) and d)
below.**

b) A design factor of 0.60 or less must be used in the design formula for steel pipe in Class 1 locations that:

- (1) Crosses the right-of-way of an unimproved public road, without a casing;
- (2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
- (3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
- (4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

d) For Class 1 and 2 locations, a design factor of 0.50, or less, must be used in the design formula for:

- (1) Steel pipe in a compressor station, regulating station, or measuring stations, and;
- (2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

Circle the criteria used above to determine the design factor, and enter here.

F =



4. Longitudinal Joint Factor (E): (49 CFR 192.113)

The longitudinal joint factor to be used in the design formula is determined in accordance with the following table:

Specification and Pipe Class	Longitudinal Joint Factor

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other"

Circle the Criteria used above to determine the Longitudinal Joint Factor, and Enter here.

E=



5. Temperature Derating Factor (T) (49 CFR 192.115)

The temperature derating factor to be used in the design formula is determined as follows:

Gas Temperature	Temperature Derating Factor (T)

For immediate gas temperatures, the derating factor is determined by interpolation.

Circle the Criteria used above to determine the Temperature Derating Factor, and Enter here.

T=

6. Nominal Outside Diameter (D)

Enter the Nominal Outside Diameter of the pipe in inches here.

D=

7. Design Pressure - Nominal (P)

Use the results of steps 1-5 above in the following formula to calculate the nominal design pressure.

$$P = \frac{2 * S * t}{D} * F * E * T$$

P= $\frac{2 * \quad * \quad *}{\quad} * \quad * \quad *$

P=



Form F-192.619

MAOP Determination

8. Design Pressure - adjustment (P)

If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75% of the pressure determined above, if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than one hour.

If applicable, multiply the result from step 7 by 0.75, and enter the result here:

P= N/A

9. Alternative Design Pressure (P)

For steel pipelines being converted under 49 CFR 192.14, or updated under 49 CFR 192 Subpart K, if any variable necessary to determine the design pressure as calculated in steps 1-7 is unknown, one of the following pressures is to be used as the design pressure:

- (i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in Table 1 of the Test Pressure Calculations; or
- (ii) If the pipe is 324 mm (12 3/4 in) or less in outside diameter and is not tested to yield under this paragraph, 1379 kPa (200psig)

If applicable, circle the criteria used above to determine the design pressure and enter it here:

P= N/A

10. Design Pressure - Final (P)

Select the appropriate design pressure from steps 7, 8, or 9 and enter it here:

P=



1. Test Pressure after construction		psi.										
2. Test Derating Factor Plastic Pipe = 1.5 Steel Pipe: If the pipeline is operated at 100 psig or more, select the appropriate factor from below:												
<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <th style="padding: 5px;">Class Location</th> <th style="padding: 5px;">Installed before Nov. 12, 1970</th> <th style="padding: 5px;">Installed after Nov. 11, 1970</th> <th style="padding: 5px;">Converted under §192.14</th> </tr> <tr> <td style="height: 50px;"></td> <td></td> <td></td> <td></td> </tr> </table>	Class Location	Installed before Nov. 12, 1970	Installed after Nov. 11, 1970	Converted under §192.14					<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 60%; padding: 10px;"> Test Derating Factor = </td> <td style="width: 40%;"></td> </tr> </table>		Test Derating Factor =	
Class Location	Installed before Nov. 12, 1970	Installed after Nov. 11, 1970	Converted under §192.14									
Test Derating Factor =												
If the Pipeline is operated below 100 psig, enter 1.0 as the test derating factor.												
3. MAOP Limited by Test Pressure		psi.										
Line 1 divided by Line 2	N/A	psi.										

*For offshore segments uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.



Form F-192.619

MAOP Determination

Operating and Hydrostatic Test Pressures for Valves			
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressure	
		Shell	Seat

Operating and Hydrostatic Pressures for Flanges		
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressures

Components with a Design Pressure Less Than the Valve or Flange Rating (If Applicable)			
Description of Component	ANSI Class	Maximum operating Pressure	Hydrostatic Test Pressure

Temporary Piping Blinds Blind Thickness (Inches) for Flange Sizes * Blinds Cut from ASTM A36 Carbon Steel Plate for Maximum Actual Hydrostatic Pressure as Given						
Nominal Pipe Size	ANSI 150	ANSI 300	ANSI 600	ANSI 900	ANSI 1500	ANSI 2500
	285 psig	740 psig	1480 psig	2220 psig	2500 psig	3000 psig





**When to Use
This Form**

This form is to be used to properly document leakage surveys along the pipeline.

**Reviewed
Procedures**

☐ P-192.706 *Leakage Surveys*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-192.706.
2. Immediately after a potential leak is found, contact Pipeline Coordinator/Supervisor for an investigation.
3. Investigation must be documented using form WTG 1101.
4. Retain records for 5 years.



Company Name:		State:	
District:			
Date:		Location:	
Type of Line: <input type="checkbox"/> Transmission () Odorized () Un-Odorized <input type="checkbox"/> Gathering <input type="checkbox"/> Distribution			
Line Material: <input type="checkbox"/> Unprotected Steel <input type="checkbox"/> CP Protected Steel <input type="checkbox"/> Polyethylene (PE) <input type="checkbox"/> Other Plastic (PVC, ABS)			
System Name:		Transmission:	
Survey Frequency:		Class <input type="checkbox"/> 1 <input type="checkbox"/> 2 <input type="checkbox"/> 3 <input type="checkbox"/> 4	
TRC ID #:		Distribution:	
		Business District <input type="checkbox"/>	
		Non-Business District <input type="checkbox"/>	
		Complete System <input type="checkbox"/>	
Was gas detection equipment used? <input type="checkbox"/> Yes <input type="checkbox"/> No			
What Type/Model:			
Serial Number:			
Leaks Found: <input type="checkbox"/> No <input type="checkbox"/> Yes			
If YES, describe findings below and complete WTG-1101 Leak Report Form			
Completed by:		Date:	



**When to Use
This Form**

This form is to be used to properly document aerial leakage surveys along the pipeline.

**Reviewed
Procedures**

☐ P-192.706 *Leakage Surveys*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-192.706.
2. Immediately after a potential leak is found, contact Pipeline Coordinator/Supervisor for an investigation.
3. Investigation must be documented using form WTG 1101.
4. Retain records for 5 years.



Company Name:		State:
District:		
Date:	Location:	
Type of Line: <input type="checkbox"/> Transmission () Odorized () Un-Odorized <input type="checkbox"/> Gathering		
Line Material: <input type="checkbox"/> Unprotected Steel <input type="checkbox"/> CP Protected Steel <input type="checkbox"/> Poly		
System Name:	Transmission:	
TRC ID #:	Class <input type="checkbox"/> 1 <input type="checkbox"/> 2 <input type="checkbox"/> 3 <input type="checkbox"/> 4 Complete System <input type="checkbox"/>	
Was gas detection equipment used? <input type="checkbox"/> Yes <input type="checkbox"/> No <input type="checkbox"/> Vegetation		
What Type/Model:		
Serial Number:		
Leaks Found: <input type="checkbox"/> No <input type="checkbox"/> Yes		
If YES, describe findings below and complete WTG-1101 Leak Report Form		
Leak Indications		GPS Coordinates
Completed by:		Date:



**When to Use
This Form**

This form is to be completed by any personnel that discovered a needed repair. It should also be used in conjunction with procedure P-192.709 to document all repairs as they are complete.

**Reviewed
Procedures**

☐ P-192.711 *Pipeline Repairs*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and replace the original. Do not mark on the original version of this form.
2. Complete the Repair Request and forward to the appropriate individual/work group.
3. File the form in file 192.709. Retain records for the life of the pipeline system.



Repair Request

Equipment Description:	
Equipment Location:	
Problem discovered by:	On date:
Describe problem and recommend repair:	
Work Order forwarded to:	On date:
Work Order forwarded by:	

Repair Results

Description of repair work performed:	
Repair work completed by:	On date:



**When to Use
This Form**

This form is to be used in conjunction with Procedure P-192.727 to properly document the abandonment of a pipeline.

**Reviewed
Procedures**

☐ P-192.727 *Abandonment or Inactivation of Facilities*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Make a copy of this form and replace the original in the file. Do not mark up the original copy of this form.
2. Gather data and complete form.
3. If this abandonment is for a pipeline that is offshore or crosses a commercially navigable waterway, file a report of abandonment of that facility. This report should be done through the NPMS and should include: NPMS required attributes, date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and that the abandonment was completed in accordance with applicable laws.
4. Place completed form into DOT File 192.727. Retain records for the life of the pipeline system.



Company:		District/Location:	
System:		Type of Service	
Description of Facility:			
Location	City:	County:	State:
	Section:	Township:	Range:
Date placed in service:		Date Abandoned:	
Type of abandonment: <input type="checkbox"/> In place <input type="checkbox"/> Removed If abandoned in place, describe final disposition of ownership (attach additional pages if necessary).			
Purged with:		Filled with:	
Describe procedure used to insure that no volatile flammable hydrocarbons remained in the facilities (attach additional pages if necessary):			
Completed by:			Date:



**When to Use
This Form**

This form, in conjunction with procedure P-192.731(a), is used to properly document maintenance performed on overpressure safety devices on the pipeline and at compressor stations.

**Reviewed
Procedures**

☐ P-192.731(a) *Compressor Relief Devices*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Perform inspection according to procedure P-192.731(a).
2. Complete this form.
3. Identify any needed follow-up items. List on this form and forward to supervisor.
4. Prior to filing this form, investigate all items marked for follow-up and note the action taken.
5. Place completed form in DOT File. Retain records for 5 years.



Follow-up Items

Note items that require immediate remedial action.

Action Item (Problem)	Action Taken	Date	Signed



Compressor Station Relief Devices

Valve Inspection	Is there significant external corrosion?	<input type="checkbox"/> Yes <input type="checkbox"/> No
	Are there broken/missing bolts on the valve body?	<input type="checkbox"/> Yes <input type="checkbox"/> No
	Are there broken/missing bolts on the flanges?	<input type="checkbox"/> Yes <input type="checkbox"/> No
	Are there leaking flanges or gaskets?	<input type="checkbox"/> Yes <input type="checkbox"/> No
	Are there leaking packing or seals?	<input type="checkbox"/> Yes <input type="checkbox"/> No
At what pressure is the pressure control device set?		_____psi
Is this the specified pressure?		<input type="checkbox"/> Yes <input type="checkbox"/> No
Have any operational changes occurred since installation that might exceed this valve's design capacity or cause it to be otherwise unfit for this service?		
<input type="checkbox"/> No		
<input type="checkbox"/> Yes (send a copy of this form to engineering)		
Explain:		
Are there any conditions that might prevent this device from functioning properly?		
<input type="checkbox"/> No		
<input type="checkbox"/> Yes (send a copy of this form to engineering)		
Explain:		
Comments:		
Completed by:		Date:



**When to Use
This Form**

This form, in conjunction with procedure P-192.731(c), is used to properly document maintenance performed on emergency shutdown devices at compressor stations.

**Reviewed
Procedures**

☐ P-192.731(c) *Compressor Station ESD System*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Perform inspection according to appropriate procedure P-192.731(c).
2. Complete this form.
3. Identify any needed follow-up items. List on this form and forward to supervisor.
4. Prior to filing this form, investigate all items marked for follow-up and note the action taken.
5. Place completed form in DOT File. Retain records for 5 years.



Follow-up Items

Note items that require immediate remedial action.

Action Item (Problem)	Action Taken	Date	Signed



Compressor Station:		Date of Test:	
<input type="checkbox"/> Review Procedure P-192.167			
<input type="checkbox"/> Contact Control Center to Coordinate Test			
Disarm appropriate blowdown valves, install caps, and re-arm			
List valves here:			
<input type="checkbox"/>		<input type="checkbox"/>	
<input type="checkbox"/>		<input type="checkbox"/>	
<input type="checkbox"/>		<input type="checkbox"/>	
Give the START signal, then actuate the ESD station to initiate shutdown			
ESD Station:			
Location:			
Time Actuated:			
Confirm operation of all relevant valves			
List valves here:			
<input type="checkbox"/>		<input type="checkbox"/>	
<input type="checkbox"/>		<input type="checkbox"/>	
<input type="checkbox"/>		<input type="checkbox"/>	
Record time after all valves operate		Time:	
Verify ESD detected by:		<input type="checkbox"/> Control Center	
<input type="checkbox"/> Other:		<input type="checkbox"/> Other:	
<input type="checkbox"/> Other:		<input type="checkbox"/> Other:	



Close appropriate valves, disarm, remove caps, and re-arm.

List valves here:

☐☐☐☐☐☐

Slowly open the appropriate valves to pressurize the station piping

List valves here:

☐☐☐☐☐☐

Confirm the positions of the following valves

List valves here:

☐☐☐☐☐☐

Notify Control Center when station is ready to come on line.

Add horsepower to maintain required pressure.

Close station block valves and disarm

List valves here:

☐☐☐☐



Re-arm valves after adequate differential pressure builds

List valves here:

☐☐☐☐☐☐

Record time station back on line

Time:

Comments (include any problems or malfunctions and how they were corrected):

Participating Personnel:

Test conducted by:

Qualified Individual Signature:



**When to Use
This Form**

This form, in conjunction with procedure P-192.731(a), is used to properly document maintenance performed on gas detection and alarm equipment at compressor stations.

**Reviewed
Procedures**

☐ P-192.736 *Compressor Station Gas Detection*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Perform inspection according to appropriate procedure P-192.736.
2. Complete this form.
3. Identify any needed follow-up items. List on this form and forward to supervisor.
4. Prior to filing this form, investigate all items marked for follow-up and note the action taken.
5. Place completed form in DOT File. Retain records for 5 years.



Follow-up Items

Note items that require immediate remedial action.

Action Item (Problem)	Action Taken	Date	Signed



Location	Zero		Span		Notes
	As Found	As Left	As Found	As Left	
Comments:					
Qualified Person Signature:					Date:



**When to Use
This Form**

This form is to be used in when inspecting the capacity of pressure relief devices.

**Reviewed
Procedures**

☐ P-192.739 *Inspect, Calibrate, & Maintain Overpressure
Safety Devices*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Gather data and complete the above form.
2. Identify any needed repairs.
3. Retain records for 2 years.



Device	Test PSI	Size	Capacity	Orifice	Line Volume	Date



**When to Use
This Form**

This form is to be used in conjunction with procedure P-192.749 whenever a Vault Inspection or Maintenance is performed.

**Reviewed
Procedures**

☐ P-192.749 *Vault Inspection*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**OQ Covered
Task**

1351 Vault Inspection and Maintenance

Once each calendar year not to exceed 15 months



District:		System Name:	
Safety Precautions:			
<input type="checkbox"/> Motor vehicle shut off in vicinity of vault		<input type="checkbox"/> Lighting	
<input type="checkbox"/> Dry Chemical Fire Extinguisher		<input type="checkbox"/> CGI (Probe inserted into Vault)	
<input type="checkbox"/> Safety Harnesses		<input type="checkbox"/> Area Checked for Hazards	
<input type="checkbox"/> Breathing Apparatus		<input type="checkbox"/> Minimum 2 People	
<input type="checkbox"/> Complete Confined Space Entry			
O2 (>19.5 but <23.5%) <input type="checkbox"/>		If combustibles are in excess of 60% LEL DO NOT ENTER	
Personal Protective Equipment PPE :			
<input type="checkbox"/> Safety Glasses		<input type="checkbox"/> Goggles <input type="checkbox"/> Face Shield <input type="checkbox"/> Hearing Protection	
<input type="checkbox"/> Hard Hats		<input type="checkbox"/> Gloves <input type="checkbox"/> Protective Boots	
Ladder Condition:		Interior Condition:	
		Wall Condition:	
Piping Condition (flanges, pipe, fittings):			
Please enter any information of concern:			
Condition of Right of Way:			
AOC Found:			
<input type="checkbox"/> Yes <input type="checkbox"/> No			
Completed by:		Date:	
Supervisor:		Date:	



**When to Use
This Form**

This form is used to provide OCC with Notice of Construction prior to construction of a new pipeline, or relocation, or replacement of a pipeline.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Complete form OCC-PSR 5001.
2. A copy of the form shall be retained for the life of the pipeline system. The original shall be sent to the proper agency in accordance with state regulations.



<http://www.occeweb.com/tr/PLSNoticeConst5001.pdf>



**When to Use
This Form**

This form is to be used to properly document leak complaints and leak complaint investigations.

**Reviewed
Procedures**

☐ TAC-8.205 Leak Management

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure TAC-8.205.
2. Complete leak investigation.
3. Investigation and remediation must be documented using Form TAC-8.205. This form also can be downloaded off of the ASI program.
4. Retain records for the life of the pipeline system.



Date Reported: _____ Time Reported: _____ ☐ AM ☐ PM

Name: _____

Address: _____ City / State / Zip: _____

Leak Reported By: ☐ Customer ☐ Police / Fire Department ☐ Inspector ☐ Employee
☐ Employee ☐ Person Causing Damage
☐ Other: _____

Reporting Persons Name: _____ Telephone #: _____

Other Information: _____

Nature of Complaint: ☐ Gas Odor ☐ Fumes ☐ Visible / Audible Leak
☐ Construction Damage ☐ Vegetation Damage ☐ Other

Reported Location:

Inside Building:

☐ Odor Throughout ☐ In Kitchen ☐ At Water Heater ☐ At Furnace ☐ Other: _____

Outside Building:

☐ General Odor in Air ☐ At Meter ☐ In Alley ☐ At Street ☐ Other: _____

Remarks:

Call Received By: _____

Call Dispatched To: _____

For Field Personnel

Time of Arrival: _____ Time of Departure: _____

Leak Found On: ☐ Customers Facility ☐ WTG Facility ☐ No Leak Found

Notes: Leaks found on WTG facilities will need to be documented using Form WTG-1101

Customers Facility: (Signature from customer is required when leak is found on their facility)

Shut In Test: Number of Minutes: _____ Cubic Feet Passed: _____

Leak: ☐ Yes ☐ No Gas Left: ☐ Off ☐ On

Meter Locked: ☐ Yes ☐ No Meter Pulled: ☐ Yes ☐ No



Time Leak Made Safe: _____

Repairs Made:

Comments / Instructions

Customer Signature: _____

Leak Investigation Done By: _____ Signature: _____

If Reported by the Public: The Supervisors review must be completed by 10:00am of the following business day.

Was the Leak Reported by the Public? ☐ Yes ☐ No

If Yes, Date and Time of Supervisor Review: _____

Signature of Reviewing Supervisor: _____



**When to Use
This Form**

This form is to be used to properly document the number of service riser installations checked, the condition of the coupling, and the total number of compression couplings replaced for that reporting period.

**Reviewed
Procedures**

☐ P-TAC 8.208 *Mandatory Removal and Placement Program for
Gas Distribution Systems*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-TAC 8.208.
2. Inspect, Repair and Replace every 6 months.
3. Document
4. Place completed record in DOT File. Retain records for the life of the pipeline system.

Pipeline:	Location:
Date:	Reporting Period:
Number of service rider installations checked:	
Condition of the coupling:	
Total number of compression couplings replaced:	
Notes:	
Completed by:	Date:



**When to Use
This Form**

This form is to be used to properly document meeting attendance.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Each employee in attendance must print and sign their name on the form.
2. Form shall be retained in compliance with applicable regulations.

Date: _____

District Location: _____

Topic: _____

Instructor: _____

Short detail of topics discussed:

[illegible]



**When to Use
This Form**

This form is to be used in conjunction with procedure P-192.459 whenever an examination of exposed metallic pipe for evidence of external corrosion is needed.

**Reviewed
Procedures**

- ☐ P-192.459 *External Examination of Exposed Pipe*
☐ P-192-614 Damage Prevention Program

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each exposed pipe.
3. Retain records for 5 years.

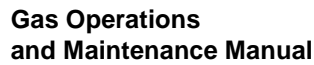


District:		System Name:	
Reason for Exposing Pipeline: Additional Comments Below if Needed _____			
Pipe Location (Include distance from Structures and/or Roads): 			
Latitude:		Longitude: <i>(Additional Marker Ball locations can be entered on next page)</i>	
Type of Line:		Line Material:	
Required if Steel: Any Pipe Removed? _____			
UT Reading _____		Pipe-to-Soil Reading: _____VDC	
Type of Cathodic Protection: <input type="checkbox"/> None <input type="checkbox"/> Anodes <input type="checkbox"/> Impressed <input type="checkbox"/> Other _____			
Pipe Size:	Operating Pressure:		MAOP:
Pipe Depth:	Wall Thickness:		Tracer Wire:
Please enter any pipe information found (Manufacturer, Date Manufactured, etc.): 			
Coating Type:		Coating Condition:	
External Pipe Condition:		Internal Pipe Condition:	
Soil Type: <input type="checkbox"/> Sandy <input type="checkbox"/> Clay <input type="checkbox"/> Loam <input type="checkbox"/> Sandy, Clay, & Loam <input type="checkbox"/> Other _____			
List Foreign Structures in Immediate Area: 			



Condition of Right of Way:	
AOC Found? <input type="checkbox"/> Yes <input type="checkbox"/> No	Physical Attributes Match Mapping Data: <input type="checkbox"/> Yes <input type="checkbox"/> No
Marker Ball Installed? <input type="checkbox"/> Yes <input type="checkbox"/> No <i>Utilize cells below if additional marker balls added in area</i> Add Additional Location Remarks Below	
Latitude:	Longitude:
Latitude:	Longitude:
Latitude:	Longitude:
Latitude:	Longitude:
Latitude:	Longitude:
Latitude:	Longitude:
Latitude:	Longitude:
Completed By:	
Date:	
Reviewing Supervisor:	
Date:	

Retain in District records for at least 5 years and email copy to wtgmapping@westtexasgas.com



**Form WTG-1101
Leak Report Form
Revision April 2022**

NORTH

This image shows a full page of dot grid paper. It features a solid black rectangular border around the perimeter. Inside the border, there is a uniform grid of small black dots spaced evenly both horizontally and vertically, creating a guide for writing or drawing. The background is white, and the dots are consistently sized and colored throughout the entire page.

Revised April 2022



Repair Date: Leak ID#:

Height of Hole (in): Width of Hole (in): Est Pressure @ Hole:

Time Leaked (hrs): Calculated GHG: mcf @ 14.65

Enter loss in MCF if obtained by alternative measurement method: mcf

Cathodic Protection: ☐ Yes ☐ No Type Of CP: Anodes

CP Readings: Before After Other Impressed

CP Remediation:

Leak Cause(*2):

If Other Leak Cause is Chosen you must explain:

MAOP:

Wall Thickness:

Leak Located(*3):

Pipe Depth (in):

Leak Located on(*4):

Tracer Wire : ☐ Yes ☐ No

Facility Type(*5):

Coating Type:

Pipe Size(Inches and decimal):

Coating Condition:

Pipe Type(*6):

External Pipe Condition:

Leak Repair Method(*7):

Internal Pipe Condition:

If leak is located on a "Compression Coupling" fill in: ☐ Material Type: ☐ Steel ☐ Plastic

Compression Coupling Installation Date:

Coupling Model:

Coupling Manufacturer:

If leak is located on a "Joint" fill in: ☐ Type of Leaking Joint(*8):

If leak is located on a "Fitting" fill in: ☐ Type of Leaking Fitting(*9):

If the pipe type is HDPE, MDPE, or PVC fill in: ☐ Pipe Manufacturer(*10):

Pipe ASTM material code(*11):

Soil Type: ☐ Sandy ☐ Clay ☐ Loam ☐ Sandy, Clay, & Loam ☐ Other

Installation Decade: Physical Attributes Match Mapping Data : ☐ Yes ☐ No

Marker Ball Installed: ☐ Latitude: Longitude:

Comments:

Repairs Completed By:

% of Gas Concentration after Repair:

Post Repair Inspection Dates and Gas Concentration(If Required):

Approved for Closing: ☐ Yes ☐ No (if no, use page 3 for final review) Date Leak approved for closing:

Supervisor completing final review: Signature

Date:

* See Field Guide for a list of choices



Leak ID#: _____

Leak re-evaluations and Post repair inspections: Please refer to P-192.706(b) of the O&M

Leak Re-evaluation 1: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Leak Re-evaluation 2: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Leak Re-evaluation 3: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Leak Re-evaluation 4: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Leak Re-evaluation 5: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Leak Re-evaluation 6: Date: _____ % of Gas Concentration: _____ Leak Grade Change? _____ Yes _____ No
New Leak Grade: _____ Comments: _____

Post-repair Inspection 1: Date: _____ % of Gas Concentration: _____

Post-repair Inspection 2: Date: _____ % of Gas Concentration: _____

Post-repair Inspection 3: Date: _____ % of Gas Concentration: _____

Post-repair Inspection 4: Date: _____ % of Gas Concentration: _____

Post-repair Inspection 5: Date: _____ % of Gas Concentration: _____

Post-repair Inspection 6: Date: _____ % of Gas Concentration: _____

Approved for Closing: _____ Yes _____ No Date Leak approved for closing: _____

Supervisor completing final review: Signature _____
Date: _____

Field Guide - Page 1

Leak Grade Description *1
Grade 1 - A Grade 1 leak is an existing or probable hazard to persons or property and requires the operator to take action immediately to eliminate the hazard and make repairs.
Grade 2 - A grade 2 Leak is non-hazardous at the time of detection, but requires the operator to schedule repair based on probably future hazard. It can be scheduled for repair on a normal routine basis with periodic re-inspection as necessary. Grade 2 leaks will be re-evaluated at least once every 30 days until they have been repaired or cleared. All Grade 2 leaks must be repaired within 6 months of detection.
Grade 3 - A Grade 3 Leak is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Grade 3 leaks shall be repaired within 36 months of detection.

Leak Cause Description *2
Corrosion
Operator Personnel/Contractors Excavation
Other Third Party Excavators
Locator
Vehicle (Auto/Truck/etc.)
Lightning
Washout
Ground Movement
Ice
Staric Electricity
Vandalism
Fire/Explosion First
Excessive Strain
Dent
Gouge
Factory Defect Defect
Wrinkle Bend
Weld (Steel)
Fusion Defect (Plastic)
Equipment Malfunction
Gasket/O-ring (Compression Coupling, etc)
Packing
Inadequate/Failure to Follow Procedures
Stripped Threads
Backfill
Other
Not Excavated

Leak Located On Description *3
Above Ground Piping
Below Ground Piping

Leak Located On Description *4
Valve
Body of Pipe
Stopcock
Fitting
Joint
Gauge Line
Riser
Regulator
Meter
Drip
Tap
Compression Coupling

Facility Type Description *5
Main
Service
Transmission

Pipe Type Code Description *6
Bare Steel
Coated Steel
Ductile Iron
Cast Iron
Galvanized
Copper
Brass
High Density Polyethylene (# starts with a 3)
Medium Density Polyethylenl (# starts with a 2)
Aldyl Polyethylene
Poly-Vinyl-Chloride (PVC & ABS)

Repair Method Description *7
Clamp Installed
Split Sleeve
Encapsulation (Pumpkins/Trident Seal/etc)
Component Replaced
Abandoned (Not Replaced)
Pipe Replaced
Greasing
Doped/Caulked
Tighten
Sealing Bell & Spigot Joint
Insertion

Field Guide - Page 2

Joint Type Code Description *8
Factory Butt Weld (Steel)
Factory Fillet Weld (Steel)
Field Butt Weld (Steel)
Field Fillet Weld (Steel)
Threaded
Mechanical Joint
Bell and Spigot
Flange
Butt Fusion (Plastic)
Socket Fusion (Plastic)
Saddle Fusion (Plastic)
Electrofusion (Plastic)
Sidewall Fusion (Plastic)
NA
Other

Fitting Type Code Description *9
Mechanical Service Tee
Heat Fusion Service Tee
Electrofusion Service Tee
Welded Service Tee
Saddle Fitting
Service Tee Cap
Anodeless Meter Riser
Threadolets/Weldolets/Sockolets
Plugs/Caps
Elbow
Nipple
Tee
Diaphragm
Other Meter Riser
Transition Fitting
Split Sleeve
Leak Clamp
Bell Joint Clamp
Meter Swivel
Union
Insulator
Other (pvc collar, etc)

Pipe Manufacturer Description (Poly or PVC) *10
Poly Pipe
Poly Pipe Inc.
CSR Polypipe
Rinker
Performance Pipe
Plexco
Driscopipe
Quail
Uponorr
Nipak
Other Manufacture, not listed or unknown

ASTM Description (Poly or PVC) *11
Polyamide PA 32312
Polybutylene PB 2110
Polyethylene PE 2306
Polyethylene PE 2406
Polyethylene PE 3406
Polyethylene PE 3408
Polyvinyl Chloride PVC 1120
Polyvinyl Chloride PVC 1220
Polyvinyl Chloride PVC 2110
Polyvinyl Chloride PVC 2116
Acrylonitrile Butadiene Styrene ABS 1210
Cellulose Acetate Butyrate CAB MH08
Cellulose Acetate Butyrate CAB S004
Reinforced Eposy Resin RTRP
Other Material Designation

LEAK CAUSE DESCRIPTION *2	
Field Personnel	
Corrosion	
Operator Personnel/Contractors Excavation	When a leak is caused by WTG personnel or WTG contractors on a pipeline that is properly located
Other Third Party Excavators	When a leak is caused by a Excavator not working for WTG on a pipeline that is properly located
Locator	Leaks caused by mis-located lines while following correct procedures Mis-locates caused by faulty locator equipment
Vehicle (Auto/Truck/etc.)	Farmers plowing fields Run over meters Heavy Equipment crushs underground line
Lightning	
Washout	Flood
Ground Movement	Cracks in PVC
Ice	
Static Electricity	
Vandalism	
Fire/Explosion First	
Excessive Strain	Ground temperature causes pipe shrinkage resulting in crack This does not include slipped PVC Collars Tree Roots exerting force on pipe
Dent	Not caused during excavation
Gouge	Not caused during excavation
Factory Defect	
Wrinkle Bend	
Weld (Steel)	
Fusion Defect (Plastic)	Slipped PVC Collar Leaking PVC Collar Leaking Poly Weld
Equipment Malfunction	Relief or Reg failure causing pressure to exceed design limits
Gasket/O-ring	Compression Couplings/Dressor Sleeves leaking around rubber seal
Packing	Leaking valves
Inadequate/Failure to Follow Procedures	Inadequate written procedures caused leak Failure to follow written procedures caused leak
Stripped Threads	Leaking Threaded Fittings
Backfill	
Other	Only pick "Other" after all other categories have been considered If you pick other, please give good description
Not Excavated	Abandoned Line Rerouted Line



**When to Use
This Form**

This form is used to properly document inspections performed on Regulators on the pipeline and at compressor stations.

**Reviewed
Procedures**

- ☐ P-192.736 Compressor Station Gas Detection and Alarm System
- ☐ P-192.739 Inspect, Calibrate, and Maintain Overpressure Safety Devices

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Perform inspection according to appropriate procedure in O&M Manual.
2. Complete respective portion of this form.
3. Identify any needed follow-up items. List on this form and forward to supervisor.
4. Prior to filing this form, investigate all items marked for follow-up and note the action taken.
5. Place completed form in DOT File. Retain records for 5 years.



Gas Operations and
Maintenance Manual

FORM WTG-1102
Regulator Station Inspection Sheet

District _____ System _____ TRC/CC UNIT _____
STATION NBR _____ LOCATION _____ GPS _____
STATION TYPE: _____ MAOP _____
SINGLE CUT _____ SERIES CUT _____ MONITOR _____ WORKING _____
PARALLEL _____ MONITOR _____ IN _____ OUT _____

REGULATOR DATA NO. 1

Size _____ Make _____
Model # _____ S/N _____
Press _____ Orifice _____
Rating _____ Size _____
Spring _____ Spring _____
Color _____ Range _____
In Press Max _____
Out Press Max _____

REGULATOR DATA NO. 2

Size _____ Make _____
Model # _____ S/N _____
Press _____ Orifice _____
Rating _____ Size _____
Spring _____ Spring _____
Color _____ Range _____
In Press Max _____
Out Press Max _____

REGULATOR DATA NO. 3

Size _____ Make _____
Model # _____ S/N _____
Press _____ Orifice _____
Rating _____ Size _____
Spring _____ Spring _____
Color _____ Range _____
In Press Max _____
Out Press Max _____

REG CAPACITY

At Max Inlet & MAOP Outlet SCFH #1 _____

#2 _____

#3 _____

Relief Valve Data No. 1

Size _____ Make _____
Model # _____ Press _____
Rating _____
Spgr _____ Range _____
Color _____

Capacity Downstream at
MAOP SCFH

#1 _____

Relief Valve Data No. 2

Size _____ Make _____
Model # _____ Press _____
Rating _____
Spgr _____ Range _____
Color _____

#2 _____

Relief Valve Data No. 3

Size _____ Make _____
Model # _____ Press _____
Rating _____
Spgr _____ Range _____
Color _____

#3 _____

INSPECTION SHEET

Bypass Locked Closed?	Y	N	N/A	Regulators stroked?	Y	N	N/A
RV Locked Open?	Y	N	N/A	Lockup checked?	Y	N	N/A
Building Okay?	Y	N	N/A	Orifice working properly?	Y	N	N/A
Fence secure?	Y	N	N/A	Seats working properly?	Y	N	N/A
Weeds cut?	Y	N	N/A	Relief valve popped?	Y	N	N/A
Bypass valve oper. & serviced?	Y	N	N/A	Relief valve insp & cleaned?	Y	N	N/A
Caution signs in place & legible?	Y	N	N/A	Was Nitrogen used?	Y	N	N/A
All vents clear & protected?	Y	N	N/A	Paint Okay?	Y	N	N/A
Inlet valve oper. & serviced?	Y	N	N/A	Atmospheric corrosion present?	Y	N	N/A
Outlet valve oper. & serviced?	Y	N	N/A	Filter replaced / cleaned?	Y	N	N/A
Slam valve insp & cleaned?	Y	N	N/A	Relief Blk Valve oper & serviced?	Y	N	N/A

Regulator Settings As Left

Reg No 1 _____ psi Reg No 2 _____ psi Reg No 3 _____ psi Rel No 1 _____ psi Rel No 2 _____ psi Rel No 3 _____ psi

Slam Valve Settings As Left

_____ psi _____ ppm _____ other

Date Inspected _____ AOC's Found Y N Person Qualified? Y N

Note: This inspection sheet must agree with the equipment installed. Any changes to MAOP, orifice size, relief valves, orifices or springs require revisions to the sheet and the regulator design sheet. Is there anything on the station that does not agree with this form, or is not consistent with the operation conditions? Y N If yes, please note in REMARKS on back of this form(if needed check here)

Inspector Signature _____

AOC's Y N

Reviewing Supervisor _____

Revised: May 2022



**When to Use
This Form**

This form is to be used to properly document the inspection and investigation of any findings on the pipeline Right of Way. These inspections will be completed according to class location as described below. The Right of Way inspection may be done from the air or the ground.

Class 1 and 2 – 1 time per calendar year at intervals not to exceed 15 months (increase to 2 times per year at intervals not to exceed 7 ½ months at highway and railroad crossings)

Class 3 – 2 times per calendar year at intervals not to exceed 7 ½ months (increase to 4 times per year at intervals not to exceed 4 ½ months at highway and railroad crossings)

Class 4 – 4 times per calendar year at intervals not to exceed 4 ½ months (same at highway and railroad crossings)

.

**Reviewed
Procedures**

☐ P-192.705 *Right-of-Way Inspections*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Refer to procedure P-192.705.
2. Immediately after a potential issue is found, contact Pipeline Coordinator/Supervisor for an investigation.
3. Investigation must be documented in writing on the back of this form.
4. Document all encroachments using F-192.614.
5. Retain records for 2 years.



District _____ System _____ TRC/OCC UNIT _____

PATROL POINT ID _____

Transmission Class Locations for Patrol Area 1 2 3 4
Distribution Business District Non-Business District Road & RR Crossing? Yes No

Notice: If leaks and/or integrity problem(s) found, the DM must take action.

TYPE OF PATROL: WALK DRIVE AIRPLANE

AREAS COVERED BY THIS PATROL:

DESCRIBE ANY LEAK INDICATORS: LEAKS FOUND? YES NO

DESCRIBE ANY CONSTRUCTION ACTIVITIES

DESCRIBE ANY UNUSUAL CONDITIONS AT HIGHWAY OR RAILROAD CROSSINGS

RIGHT-OF-WAY CONDITION

ANY POTENTIAL INTEGRITY PROBLEMS: YES NO

DESCRIBE ANY FACTORS THAT COULD AFFECT THE PIPELINE'S INTEGRITY

EMPLOYEE CONDUCTING THE PATROL: _____

DATE OF THE PATROL: _____

If yes, provide details:

DISTRICT MANAGER
(or designated
personal)

DATE



**When to Use
This Form**

This form is to be used in when inspecting emergency valves.

**Reviewed
Procedures**

☐ P-192.745 *Valve Inspection and Maintenance*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each valve inspection.
3. Identify any needed repairs.
4. Retain records for 5 years.



District

Agency ID

System Type

System Name

Lat

Long

Name

Number

Size

Type

Location

Manufacturer

Material

Status

ANSI Rating

Valve Accessible

Yes

No

Partially Operated

Yes

No

Lubricated

Yes

No

Protected from Tampering

Yes

No

Operational Method

If Remote, describe method of point to point verification below

Remarks:

Name of Inspector

Date

Were there any Abnormal Operating Conditions that would affect Pipeline Integrity?

Yes

No

If yes, reviewed by
District Manager

Date



Complete XLS form from web

Gas Operations and Maintenance Manual

**Form WTG-1200
Rectifier Inspection Form
Rev 1 - January 2022**

When to Use This Form

This form packet is used to document inspection of rectifiers.

Reviewed Procedures

P-192.465(b) *Inspect/Test/ Repair Rectifiers*

P-192.465(c) *Inspect Reverse Current Switches, Diodes, and
Interference Bonds*

P-192.483 *Cathodic Protection Remediation*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

Documentation Procedure

1. Copy this form and return original to manual.
 2. Refer to Corrosion Control Procedures to ensure inspections are done correctly.
 3. Gather data and complete form. One section should be completed for each inspection (once every 2 months).
 4. If corrosion is found or there is a suspected need for remediation, document below and forward this document to the Corrosion Control Engineer for immediate review.
 5. Place completed form in file. Retain for the life of the line.
-

Form Version

Rev 1 - January 2022



**Gas Operations and
Maintenance Manual**

**Form WTG-1200
Rectifier Inspection Form
Rev 1 - January 2022**

District				System	
Location				Pipeline Name	
County		State		TRC/CC Unit	

2. RECTIFIER INFORMATION:

Please keep your rectifier clean

Manufacturer				Rectifier ID/Name			
Model No.				Power Vendor			
Serial No.		Acct #		KWH Meter #		KWH Reading	
DC Volts		AC Volts		Max Coarse		Shunt mV/Shunt Factor	
DC Amps		AC Amps		Max Fine			
GPS Coordinates	Latitude	N		Longitude	W		
RMU Type				RMU Serial No.			

3. JUNCTION BOX INFORMATION:

J box Shunt Factor

Anode Junction Box				Positive Cables (Continuous Anode)			Negative Junction Box		
Cir.	Amp	Cir.	Amp	Cir.	Description	Amp	Cir.	Description	Amp
1		11		1			1		
2		12		2			2		
3		13		3			3		
4		14		4			4		
5		15		5			5		
6		16		6			6		
7		17		7			7		
8		18		8			8		
9		19		9			9		
10		20		10			10		
Total		0.00		Total		0.00	Total		0.00

4. RECTIFIER OPERATING HISTORY:

Technician	Date	Test			Taps		Unit		Remarks
		Volts	Amps	Ohms	C	F	Adjust		
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	
							<input type="checkbox"/> As Found <input type="checkbox"/> As Left	<input type="checkbox"/> AOC?	

REMARKS:



**When to Use
This Form**

This form is used to document inspection of interference bonds on the pipeline.

**Reviewed
Procedures**

- ☐ P-192.465(b) *Inspect/Test/ Repair Rectifiers*
- ☐ P-192.465(c) *Inspect Reverse Current Switches, Diodes, and Interference Bonds*
- ☐ P-192.483 *Cathodic Protection Remediation*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Refer to Corrosion Control Procedures to ensure inspections are done correctly.
3. Gather data and complete form. One section should be completed for each inspection (once every 2 months).
4. If corrosion is found or there is a suspected need for remediation, document below and forward this document to the Corrosion Control Engineer for immediate review.
5. Place completed form in file. Retain records for the life of the pipeline system.



District _____ System _____ GPS _____

STATION ID: _____

IB STATION TYPE:

DATE	PIPE TO SOIL POTENTIALS				REMARKS
	WTG		FOREIGN		
	BOND ON	BOND OFF	BOND ON	BOND OFF	

NAME OF INSPECTOR _____ DATE _____



Complete XLS form from web

***Gas Operations and
Maintenance Manual***

**Form WTG-1202
Atmospheric Corrosion Survey
Rev 2 - January 2022**

**When to Use
This Form**

This form packet is used to document inspection of pipelines that are exposed to the atmosphere.

**Reviewed
Procedures**

P-192.479 *Protection Against Atmospheric Corrosion*

P-192.481 *Visually Inspect for Atmospheric Corrosion*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Refer to Corrosion Control Procedures in the O&M Manual to ensure inspections are done correctly.
3. Gather data and complete form.
4. If corrosion is found or there is a suspected need for remediation, document below and forward this document to the Corrosion Control Engineer for immediate review.
5. Place completed form in file. Retain records for the life of the pipeline system.

Form Version

Rev 2 - January 2022



**Gas Operations and
Maintenance Manual**

**Form WTG-1202
Atmospheric Corrosion Survey
Rev 2 - January 2022**

Survey Year:

District:

Facility Type:	<input type="text"/>	<input type="text"/>	TRC/CC Unit	<input type="text"/>
System Type:	<input type="text"/>	Latitude	<input type="text"/>	Longitude
Facility Description:	<input type="text"/>			
System:	<input type="text"/>			
Line Segment:	<input type="text"/>			

Examine facility piping for corrosion

Corrosion found?

Non-destructive testing performed?

Comments/Description:

Air to soil interface coating condition: Comments/Description Below:

Support structures, fence and building coating condition: Comments/Description Below:

Corrosion under clamps or between pipe and saddle

Are pipe supports mechanically stable?

Comments/Description:

Paint Condition?

If pitting was found, were the Specialist and Supervisor notified:

Please record any observations:

Remedial Actions required?

If Yes, provide description below:

Date Remedial Actions completed:

Signature:

Inspector's Signature:

Date:



**When to Use
This Form**

This form is used to document the pipe-to-soil corrosion control surveys and the testing of any non-critical bonds.

**Reviewed
Procedures**

- ☐ P-192.465(a) *Conduct Cathodic Protection Surveys*
- ☐ P-192.467 *Electrical Isolation*
- ☐ P-192.469 *Corrosion Control Test Stations*
- ☐ P-192.483 *Cathodic Protection Remediation*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Refer to Corrosion Control Procedures in the O&M Manual to ensure inspections are done correctly.
3. Gather data and complete form as applicable.
4. If corrosion is found or there is a suspected need for remediation, document below and forward this document to the Corrosion Control Engineer for immediate review.
5. Place completed form in file. Retain for the life of the line.



**Gas Operations and
Maintenance Manual**

**FORM WTG-1203
Cathodic Protection**

District _____ System _____ TRC/CC Unit _____

CLASS LOCATIONS _____ (Enter 1, 2, 3, or 4)

TEST STATION TYPE

TYPE OF SYSTEM: _____ TRANSMISSION _____ DISTRIBUTION _____ GATHERING _____

Test Station	Location	Pipe-To-Soil Readings (-Volts or -mV)						
		P/S Reading	Foreign Reading	Casing Reading	Repaired Reading	Repaired Date (If Applicable)	AOC Yes / No	Comments



Test Station	Location	Pipe-To-Soil Readings (-Volts or -mV)						AOC Yes / No	Comments
		P/S Reading	Foreign Reading	Casing Reading	Repaired Reading	Repaired Date (If Applicable)			

Inspected By: _____

Date: _____



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DISTRICT: _____ SYSTEM: _____ TRC/CC UNIT: _____

ODORIZER LOCATION: _____ ODORIZER MAKE & TYPE: _____
ODORIZER NUMBER: _____

GPS: _____ LAT: _____ LONG: _____ MALODORANT BRAND: _____

BYPASS OR INJECTION: _____ TANK CAPACITY: _____ GALLONS or POUNDS: REQUIRED

SURVEY FREQUENCY: _____

YEAR	ODORANT USAGE IN POUNDS				COMMENTS OR ADJUSTMENTS	TOTAL OF MONTH GAS MCF	TOTAL OF MONTH GAS MMCF	RATE OF ODORIZATION Pounds per MMCF	DATE & PERSON RESPONSIBLE
	First of Month Read	Amount Added	Last of Month Read	Total Used					
JAN				0.00			0.000	0	
FEB				0.00			0.000	0	
MAR				0.00			0.000	0	
APR				0.00			0.000	0	
MAY				0.00			0.000	0	
JUN				0.00			0.000	0	
JUL				0.00			0.000	0	
AUG				0.00			0.000	0	
SEPT				0.00			0.000	0	
OCT				0.00			0.000	0	
NOV				0.00			0.000	0	
DEC				0.00			0.000	0	

** Yellow Cells Formulas - Do not enter values



**When to Use
This Form**

This form is used to document the proper operation and appropriate concentration of odorant in farm tap.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Gather data and complete form as applicable.
3. Report any problems to management.
4. Place completed form in DOT File 192.625(f). Retain records for 5 years.



District:

System:

TRC/CC Unit:

Account Name:

Account Number:

Odorization Location:

GPS Coordinates:

MFG & Model:

Name of Malodorant:

Captan:

BP Captan:

Sential:

Other:

Condition of Equipment:

Odorizer Tank & Fittings:

Wick:

General Area:

Repairs Required:

Yes:

No:

If yes, explain:

Additional Remarks:

Signed by

Date



**When to Use
This Form**

This form is used to document the appropriate concentration of odorant in the pipeline.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Gather data and complete form as applicable.
3. Report any problems to management.
4. Place completed form in DOT File 192.625(f). Retain records for 5 years.



District _____ System _____ TRC/CC UNIT _____

TEST POINT ID _____ GPS _____

DISTANCE FROM ODORIZER _____

INSTRUMENT _____ MODEL NO. _____ SERIAL # _____

A. Odorant Concentration Meter Reading When Gas Odor Detected: _____

B. Percent Gas In Air – Odorant Concentration Meter Reading _____ Ball Type: _____

C. Specific Gravity of Gas Tested: _____

D. Correction Factor For Gravity: _____

E. Odor Concentration Meter Test Results (B % D): _____

F. Remarks:

Date _____ Time _____ AM _____ PM _____

TESTER SIGNATURE _____

WITNESSES
SIGNATURE _____



**When to Use
This Form**

This form is used to document the annual review of all operational plans.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Gather data and complete form as applicable.
3. Report any problems to management.
4. Place completed form in File. Retain for 5 years or until next review whichever is shorter.



Plan Reviewed: _____

Date Reviewed: _____

Employee Signature:

Review Outcome: _____



Project Name:

Please send project form and kmz to
wtgmapping@westtexasgas.com

PO Number:

Leak ID # if applicable:

District:

Date started:

System Name:

Date completed:

System ID#:

Class Location:

State:

County:

Address or nearest intersection:

☐ Distribution ☐ Transmission ☐ Gathering
☐ Service Only

If Transmission or Gathering, fill out Form F-192.619(MAOP Calculation) and submit to the GIS Mapping Department. MAOP forms for plastic and steel pipe can be found at www.westtexasgas.com.

☐ New Construction ☐ Replacement ☐ Abandonment

Description:

Personnel who completed project (Full Name):



Mainline Piping Removed or Installed

Definition of Main: Distribution line that serves as a common source of supply for at least one service line

Each Distribution mainline and Transmission line must be installed with the minimum amount of cover as stated in P-192.319

Does the material and size of the mainline piping removed match what is listed in the mapping program?

☐ Yes ☐ No ☐ N/A If no, please contact the Mapping Department.

Did you install new mainline piping: ☐ Yes ☐ No

If yes, complete the following:

List each mainline segment added separately by size and material:

Pipe Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other		Roll Number of Pipe:		Wall Thickness:	
Manufacturer					
Date Manufactured:		Pressure Test Performed by:			
Pressure Test Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Depth of Cover:		Amount in Feet:	

Was pipe segment stored according to P-192.69: ☐ Yes ☐ No Was pipe segment handled according to P-192.69: ☐ Yes ☐ No

Pipe Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other		Roll Number of Pipe:		Wall Thickness:	
Manufacturer					
Date Manufactured:		Pressure Test Performed by:			
Pressure Test Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Depth of Cover:		Amount in Feet:	

Was pipe segment stored according to P-192.69: ☐ Yes ☐ No Was pipe segment handled according to P-192.69: ☐ Yes ☐ No

Pipe Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other		Roll Number of Pipe:		Wall Thickness:	
Manufacturer					
Date Manufactured:		Pressure Test Performed by:			
Pressure Test Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Depth of Cover:		Amount in Feet:	

Was pipe segment stored according to P-192.69: ☐ Yes ☐ No Was pipe segment handled according to P-192.69: ☐ Yes ☐ No

If you installed more than three mainlines go to Mainline Tab at the bottom, and continue to fill out mainlines installed till completed.



Service Lines Removed or Installed

Definition of Service Line: A distribution line that transports gas from a common source of supply (mainline) to an individual customer or customers.

Did you remove any service lines: ☐ Yes ☐ No If yes, complete the following:

List each Service Line that was removed below: (If multiple services removed with same specs, enter once and type # of services)

(use if multiple services same type and size)

Service Line Material:	Size:	Decade of original installation:	Amount in feet:	Size/Type of Riser Removed:	# of services

Did you add any service lines: ☐ Yes ☐ No If yes, complete the following:

List each Service Line that was installed below: (If multiple added with same specs, enter once and type # of services)

NOTE: If lat/long of meter is submitted to ASI during install, the EFV lat/long is not required

Service Line Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other Manufacturer		Roll Number of Pipe:		Wall Thickness:	
Date Manufactured:		Pressure Test Performed by:			
Test Pressure Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Depth of Cover:		Amount in Feet:		Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No
EFV Installed and Riser Marked:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Size/Type/Height of Riser:			
GPS Coordinates of EFV:	Latitude:		Longitude:		# installed

Service Line Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other Manufacturer		Roll Number of Pipe:		Wall Thickness:	
Date Manufactured:		Pressure Test Performed by:			
Test Pressure Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Depth of Cover:		Amount in Feet:		Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No
EFV Installed and Riser Marked:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Size/Type/Height of Riser:			
GPS Coordinates of EFV:	Latitude:		Longitude:		# installed

Service Line Material:		Nominal Pipe Size:		Pipe Grade:	
Pipe Manufacturer:		Material Designation Code:		Pipe Category:	
Type if other Manufacturer		Roll Number of Pipe:		Wall Thickness:	
Date Manufactured:		Pressure Test Performed by:			
Test Pressure Date:		Test Pressure:		Test Pressure Medium:	
Outside Temperature:		Test Duration:		Pressure Test Pass/Fail:	
Depth of Cover:		Amount in Feet:		Tracer Wire Installed:	<input type="checkbox"/> Yes <input type="checkbox"/> No
EFV Installed and Riser Marked:	<input type="checkbox"/> Yes <input type="checkbox"/> No	Size/Type/Height of Riser:			
GPS Coordinates of EFV:	Latitude:		Longitude:		# installed

If you added more than three service lines go to Service Tab at the bottom, and continue to fill out services till completed.



Connecting New Pipe To Existing Pipe

Did you make any tie ins to existing pipe:

☐ Yes ☐ No

If yes, complete the following:

Tie in # 1: Material of exposed pipe:
External pipe condition:
Internal pipe condition:
Coating condition:
Depth of exposed pipe:
Size of exposed pipe:
GPS of Tie in: Latitude:
Longitude:

Coating Type:
Pipe to soil readings:
Operating pressure:
Marker ball installed: ☐ Yes ☐ No ☐ N/A
Physical attributes match mapping data: ☐ Yes ☐ No

Comments:

Tie in # 2: Material of exposed pipe:
External pipe condition:
Internal pipe condition:
Coating condition:
Depth of exposed pipe:
Size of exposed pipe:
GPS of Tie in: Latitude:
Longitude:

Coating Type:
Pipe to soil readings:
Operating pressure:
Marker ball installed: ☐ Yes ☐ No ☐ N/A
Physical attributes match mapping data: ☐ Yes ☐ No

Comments:

Tie in # 3: Material of exposed pipe:
External pipe condition:
Internal pipe condition:
Coating condition:
Depth of exposed pipe:
Size of exposed pipe:
GPS of Tie in: Latitude:
Longitude:

Coating Type:
Pipe to soil readings:
Operating pressure:
Marker ball installed: ☐ Yes ☐ No ☐ N/A
Physical attributes match mapping data: ☐ Yes ☐ No

Comments:

Tie in # 4: Material of exposed pipe:
External pipe condition:
Internal pipe condition:
Coating condition:
Depth of exposed pipe:
Size of exposed pipe:
GPS of Tie in: Latitude:
Longitude:

Coating Type:
Pipe to soil readings:
Operating pressure:
Marker ball installed: ☐ Yes ☐ No ☐ N/A
Physical attributes match mapping data: ☐ Yes ☐ No

Comments:



Material or Size Changes on Mainline

Are there any pipe material or size changes involved in this leak repair on the Mainline:

Ex: 2" Pvc to 1.25" Pvc

Ex: 2" Pvc to 2" Poly

If so please complete the following: Note: If this happens at the above tie ins then under Latitude just comment Tie-In #1, Tie-In #2, etc.

Change from:

A	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
B	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
C	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
D	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
E	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
F	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
G	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
H	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
I	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	
J	Material: Size:		TO Material: Size:		Tie-In Location: GPS: Latitude: Longitude:	



Drawing

Please attach a detailed drawing of the finished project:

Show tie in #'s from the "Tie In Page"
Show material and size changes using the letters from
the "Material or Size Change Page"

NORTH

Place the appropriate abbreviation by each joining process that was used in this project

SC	Solvent Cement	SWF	Side Wall Heat Fusion	SW	Steel Welding
SF	Stab Fitting	EF	Electrofusion	T	Threaded
BF	Butt Heat Fusion	SHF	Socket Heat Fusion	O	Other...please explain:

D Approved Dresser

Did all material used on this project meet ASTM D 2513 Standard:

☐

Yes

☐

No

Material List:



Field Guide

Mainline Pipe Material and Service Line Material will need to be picked from the Material list below:

Material Choices Are:	Coated Steel with CP	Bare Steel with CP	PVC	Other
	Coated Steel without CP	Bare Steel without CP	Poly	
Pipe Manufacturer:	Poly will be stamped on the pipe itself Steel can be found on the original paperwork PVC - If not stamped on the pipe leave blank			
Pipe Grade:	Poly will be stamped on the pipe itself, SDR 11, SDR 17, etc. Steel can be found on the original paperwork PVC will be stamped on the pipe itself, SDR 17, etc.			
Roll Number:	Poly will be stamped on the pipe itself Steel - This does not apply PVC - This does not apply			
Material Designation Code:	Poly will be stamped on the pipe itself, PE 2406, PE 2408, etc. Steel - This does not apply PVC will be stamped on the pipe itself, PVC 1120, etc.			
Pipe Category:	Poly - This is a three letter code stamped on the pipe itself, CDC, CEE, or CEC Steel - This does not apply PVC - This does not apply			
Wall Thickness:	Poly wall thickness can be found on the list on the next page Steel can be found on the original paperwork PVC - If not stamped leave blank			
Year Manufactured:	Poly will be stamped on the pipe itself Steel can be found on the original paperwork PVC - If not stamped leave blank			
Depth of Cover:	Distribution:	Minimum of 24 inches of cover		
	Transmission:	Class 1:	30 inches	
		Class 2, 3, and 4:	36 inches	

Note: "Service Line" and "Riser" are NOT considered to be the same thing.
Service line is the line that leaves the mainline and carries gas to the riser.
They can be of the same material, but we need to think of them as two different pipeline features.

Note: All GPS coordinates need to be in Decimal, Degrees and carry 5 numbers after the decimal.

Example:	Latitude:	<u>35.41465</u>
	Longitude:	<u>101.29416</u>



Poly Pipe Wall Thickness

Nominal Size	SDR	Wall Thickness	Nominal Size	SDR	Wall Thickness
1	21	0.062	6	32.5	0.204
1	17	0.077	6	26	0.255
1	13.5	0.097	6	21	0.316
1	11	0.119	6	17	0.39
1	9	0.146	6	3.5	0.491
1	7.3	0.18	6	11	0.602
			6	9	0.736
1.25	21	0.018	6	7.3	0.908
1.25	17	0.098	6	7	0.946
1.25	13.5	0.123			
1.25	11	0.151	8	32.5	0.265
1.25	9	0.184	8	26	0.332
1.25	7.3	0.227	8	21	0.41
			8	17	0.508
1.5	21	0.09	8	3.5	0.639
1.5	17	0.112	8	11	0.785
1.5	13.5	0.141	8	9	0.958
1.5	11	0.173	8	7.3	1.182
1.5	9	0.211	8	7	1.232
1.5	7.3	0.26			
			10	32.5	0.331
2	21	0.113	10	26	0.413
2	17	0.14	10	21	0.511
2	13.5	0.176	10	17	0.633
2	11	0.216	10	3.5	0.797
2	9	0.264	10	11	0.978
2	7.3	0.325	10	9	1.194
			10	7.3	1.473
3	21	0.167	10	7	1.536
3	17	0.206			
3	13.5	0.259	12	32.5	0.392
3	11	0.318	12	26	0.49
3	9	0.389	12	21	0.608
3	7.3	0.479	12	17	0.75
3	7	0.5	12	3.5	0.945
			12	11	1.16
4	21	0.214	12	9	1.417
4	17	0.264	12	7.3	1.747
4	13.5	0.333	12	7	1.821
4	11	0.409			
4	9	0.5			
4	7.3	0.616			
4	7	0.643			
5	21	0.265			
5	17	0.328			
5	13.5	0.413			
5	11	0.506			
5	9	0.618			
5	7.3	0.762			
5	7	0.795			



Complete XLS form from web

Form: Emissions Report

Emission Field Report

District:		Report Date:	
County:			
GPS Coordinates Start:			
GPS Coordinates End:			
Event/Activity type:			

Date and time event discovered or scheduled activity started:		
Date and time event or scheduled activity ended:		
Event duration:		Hours

Is the gas odorized?		
Pipe size:		IN
Pipe pressure:		PSI
Pipe flow rate (If unknown, leave blank):		MCF
Distance of pipe isolated:		FT
Was the gas flared or vented to atmosphere:		
Estimated volume of gas released (If unknown, leave blank):		MCF

Cause of emission event or excess opacity event, or reason for scheduled activity:



Description	Hot work: Is defined as any work activity which the heat used or generated by the work is intense enough to cause ignition of any flammable or combustible liquids, gases, or other combustible material.
Regulatory Applicability	All aboveground pipelines or portions of a pipeline <input checked="" type="checkbox"/> Regulated Transmission Pipelines <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type A) <input checked="" type="checkbox"/> Regulated Gathering Pipelines (Type B) <input checked="" type="checkbox"/> Regulated Distribution Pipelines
Frequency	Each time Work is performed inside a building such as but not limited to Compressor buildings, Town borders, Meter buildings, vaults, Well site buildings. Where combustible gasses and vapors exist under normal operating conditions or could exist under abnormal operating conditions.
Reference	
Forms / Record Retention	Hot Work Permit Form 30 days after completion unless there is an incident associate with the work being completed.
Related Specifications	Any WTG employee completing fire prevention training can issue a Hot Work Permit. The person issuing the permit and the person performing the work may also be the same person.

OQ Covered Task	OQ requirements are task specific, review these requirements with District Manager or Operations Manager or OQ Administrator
------------------------	--



Hot Work Permit Form

Permit Issued By: _____

Permit Issued to: _____

Location of work: _____

Work description: _____

Permit Valid for what Date: _____

Person Issuing this Permit has inspected the following:

	Yes	No	N/A
Valves have been closed Locked and Tagged?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Piping Purged?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Have Sewers and Drains been covered?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Has the atmosphere been checked with CGI?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Has area been checked possible venting gas?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Are fire extinguishers present?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Is there a need for a Fire Watch person to be Posted?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

Special Instructions to be Followed:

To be filled out by Permit Worker:

	Yes	No	N/A
Has work area been cleaned and left Safe?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Has work been completed?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Have all locks and tags been retrieved?	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

Permit Workers Signature _____



Complete WTG-PO_Request XLS form from web

PO Request for Growth Projects

District	
Will the project cost exceed \$10,000?	
Will the project cost exceed \$50,000?	
Is the project for a transmission line?	
If yes, will significant changes be made?	

Specific \$ amount seeking approval for.	
Description of the project	
Description of the commercial terms	
Description of the timeline.	
Returns	



Complete WTG-PO_Request XLS form from web

PO Request for Maintenance Projects

District	
Will the project cost exceed \$10,000?	
Will the project cost exceed \$50,000?	
Is the project for a transmission line?	
If yes, will significant changes be made?	

Specific \$ amount seeking approval for.	
Description of the project	
Description of the rationale for the project, any alternative solutions, and a brief description of what commercial end the segment/asset serves	
Description of the timeline.	

Note

These can be done in bulk. If at the beginning of the year, you've got multiple projects that will need to be done, we can approve those at the outset at the same time we get board approval for a full year budget

If it looks like cost are going to materially exceed the approved PO amount, notify this same group and refresh economics.



MOC Transmission Request

Reason for change	
Authority for approving changes	
Analysis of implications	
Acquisition of required work permits (if applicable)	
Documentation	
Communication of change to affected parties	
Time limitations (if applicable)	
Qualification of staff	



**When to Use
This Form**

This form is used to document the proper operation and appropriate concentration of odorant in the pipeline.

**Reviewed
Procedures**

None

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

**Documentation
Procedure**

1. Copy this form and return original to manual.
2. Gather data and complete form as applicable.
3. Report any problems to management.
4. Place completed form in DOT File 192.625(f). Retain for 5 years.



District _____

COMPANY NAME: _____ REP ID #: _____

DATE	ACCOUNT NUMBER	NAME OF MALODORANT	CONCENTRATE OR DILUTE	INSPECTION FREQUENCY	INSPECTION PROCEDURE

If Submitting Multiple Copies – Sign First Copy Only

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143 Texas Natural Resources Code, that I am authorized to make this report that this report was prepared by me or under my supervision and direction and that data and facts stated therein are correct and complete, to the best of my knowledge.

Signature

Date

Type or Print Name and Title

Telephone (Area Code + Number)