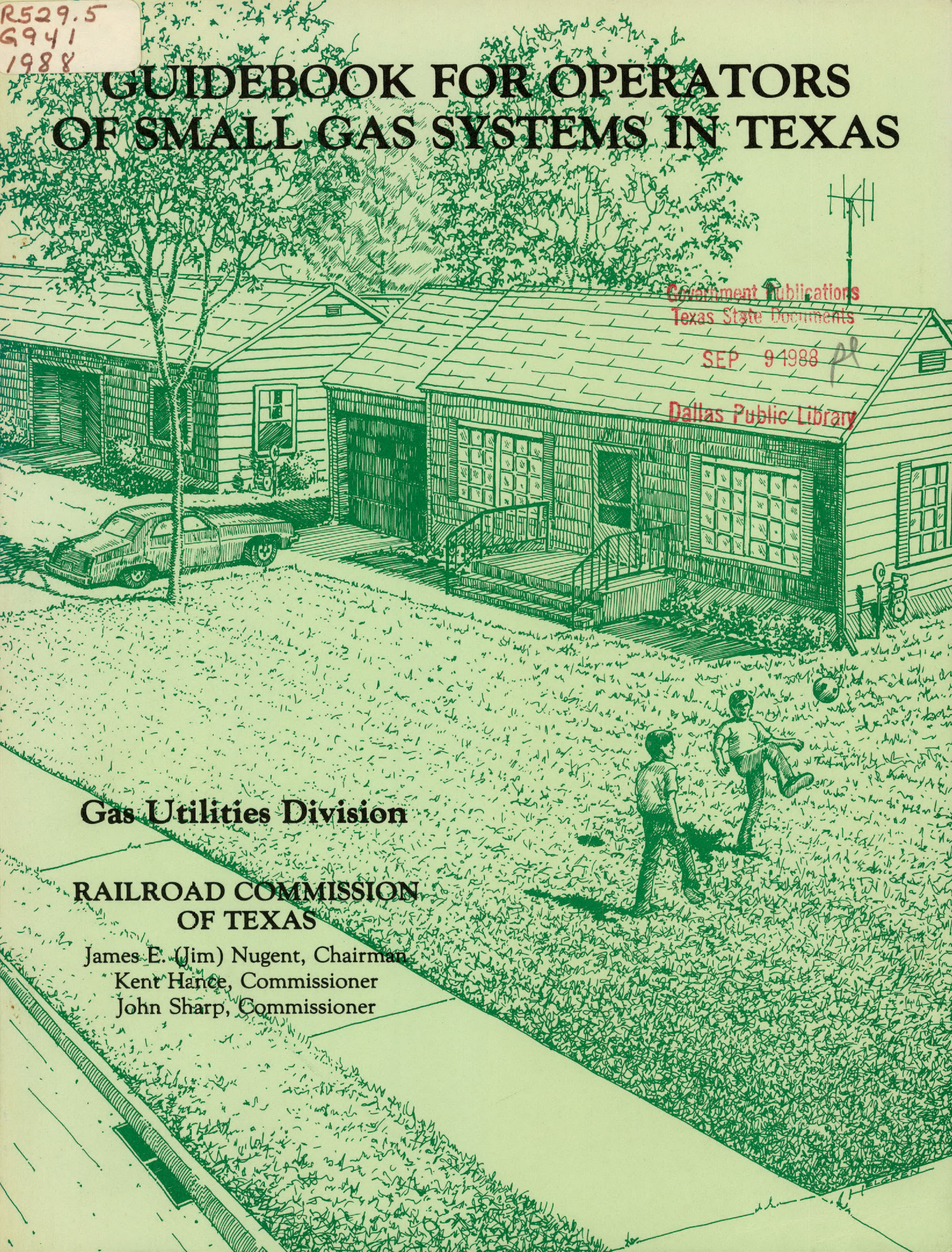
GUIDEBOOK FOR OPERATORS OF SMALL GAS SYSTEMS IN TEXAS



Gas Utilities Division

RAILROAD COMMISSION OF TEXAS

James E. (Jim) Nugent, Chairman
Kent Hance, Commissioner
John Sharp, Commissioner

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Information provided in this booklet is intended to help operators understand safety requirements and means of compliance. It is not a replacement for the actual rules and regulations. Each operator is responsible for knowing and complying with all established safety requirements, whether or not they are discussed in this manual.

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Capitol Station
Austin, Texas 78711-2967
Telephone 512/463-7058
Emergency Number: 512/447-2171

Revised March 1988

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I. Introduction

Purpose

This manual provides a very broad, general overview of your compliance responsibilities under the Minimum Safety Standards for Transportation of Natural and Other Gas by Pipeline. It has been designed for the nontechnically trained person who operates a master meter system, LP-gas system with 10 or more customers, municipal city government system, or others who operate a small system. The Railroad Commission of Texas (RRC) recognizes that most operators of small gas systems have not had extensive training in properly operating and maintaining gas systems.

Many of the regulations are in technical and performance language to allow for a variety of compliance actions for both large and small operations. Therefore, this manual attempts to simplify the technical language of the regulations. For certain critical regulations, the manual gives specific details for methods of operation and/or material selection that will meet the minimum safety requirements. Often the material given is only one of several allowable options available to the operator, and that is the material most commonly used in gas systems at the present time. The aim is to provide sufficient basic information so that the operator(s) will be able to ascertain compliance responsibilities and learn where to seek technical help.

Background

The Natural Gas Pipeline Safety Act of 1968 required the Secretary of Transportation to develop and enforce minimum safety standards for the transportation of gases by pipeline. These standards went into effect in 1970, and the RRC is charged with enforcing them. They are published in the *Federal Register*, Title 49, Code of Federal Regulations (CFR), Part 192. A copy of these standards along with additional RRC rules is available from the RRC for a nominal fee.

These regulations apply to: (a) gas utilities (private and municipal); (b) operators of housing projects, apartment complexes, and mobile home parks served by natural gas master meters; (c) liquefied petroleum gas (LP-gas) systems that supply 10 or more customers from a single source; and (d) any portion of an LP-gas system located in or near a public place, such as a highway.

All operators must comply with the minimum pipeline safety requirements.

Responsibilities of Operators

Operators of all gas systems must (at the very minimum):

1. Deliver gas safely and reliably to customers.
2. Provide training and written instructions for employees.

   NOTE: Instructions must cover safe operating and maintenance procedures during normal (day-to-day) operations. All repair procedures must meet the minimum safety requirements.

3. Establish written procedures to minimize the hazards resulting from gas pipeline emergencies.

4. Keep records of all inspections and testing.

Noncompliance

These regulations were designed to ensure safety for people and property. Therefore, operators who are found to be in noncompliance with the regulations are subject to civil penalties, compliance orders, or both. If the hazards warrant it, an order may be issued to shut down the system. (A discussion of enforcement procedures is provided in Appendix P.)

Format of the Manual

This manual is divided into seven broad and general sections. Each section begins with a brief summary in nontechnical language. The major portion of each section is a simplified, technically sound, practical discussion of compliance requirements. Appendices provide a more indepth coverage of corrosion control, leak detection, regulators and relief valves, and samples of required plans. The following is a brief description of each section:

Section I — **Introduction**

Brief explanation of RRC authority and operator responsibilities.

Section II — **Some Basic Definitions of Commonly Used Terms in the Gas Industry**

Selected technical terms and basic facts about gas and gas systems are presented in layman's language. Become familiar with these terms so that you will be able to understand the language of gas industry professionals. Additional definitions are listed by subject in the appendices.

Section III — **Reports and Plans Required by the RRC**

1. Specifies leaks that must be reported to the RRC and DOT by telephone.
2. Describes written plans and procedures that an operator must maintain. These are:
   a. Inspection and Maintenance Plan
   b. Operation and Maintenance Plan
   c. Emergency Plan
3. Discusses the written annual report that must be submitted to the RRC (instructions are included in Appendix A).

Section IV — **Materials Qualified for Use in Gas Systems**

Specific materials commonly used in gas distribution systems are discussed. Identification of material by manufacturer's marking is stressed.

Section V — **Construction and Repair**

Some basic concepts of construction and repair are covered. These include:

pre-planning, material selection, excavation, installation of steel and plastic pipe, welding, qualifying procedures and personnel for welding and joining, repair methods, and pressure testing.

Section VI — **Design and Location of Meters, Regulators, and Services**

1. Design requirements for customer meters and regulators (including their allowable locations).
2. Required location of valves in service lines.
3. Common problems to watch for at service risers and house regulators.

Section VII — **Places to Find Additional Information**

1. Buyers Guide Journals for material for gas systems.
2. Gas trade journals.
3. Organizations that publish manuals about gas safety.

Appendices — The appendices contain basic theory and common practices for leakage surveys, corrosion control, odorization, pressure regulation, overpressure protection, and welding. A listing is provided of the nearest federal regional office and all regional offices of the RRC involved in pipeline safety. Also included are sample records, which **if used and maintained by an operator, should meet the RRC record keeping requirements.** Included in Appendix E is a practical chart for a General Maintenance Schedule for the gas system. Post this chart as a reminder to follow the maintenance schedules developed in your Operation and Maintenance Plan.

The sample Emergency Plan is intended to serve as a guideline to develop your own plan.

NOTE: This manual covers the operation of small municipally and privately owned systems. Certain sections of this guidance manual will normally not apply to master meter operators. These sections are marked with an asterisk (*).

NOTES

II. Basic Definitions of Commonly Used Terms in the Gas Industry

Overview

The following is a listing by category of some common terms used in the natural gas and LP-gas industry. These terms will be used throughout the manual and are currently used in other technical manuals published for the gas industry. All definitions were kept as elementary as possible. Other definitions are listed within the appendices.

A. Operator Definitions

1. *Gas Operator* is a person who engages in the transportation of gas (jurisdictional gathering, transmission, or distribution). A gas operator may be a gas utility company, a municipality, or an individual who owns a housing project, apartment complex, or a mobile home park served by a master meter.

2. *Master Meter Operator* is a person who distributes gas within a mobile home park, housing project, condominium, apartment complex, or similar complex. The operator buys metered gas from an outside source, usually the public utility. The operator distributes and sells the gas through its own underground or exterior piping system to the ultimate consumer of the gas. The ultimate consumers may be, but need not be, individually metered (See Figure 1).

   In this figure, the gas supplier is responsible for the meter and regulator, and the master meter operator is responsible for the shaded portions. However, the operator must be aware of all inspection and maintenance performed by the gas supplier.

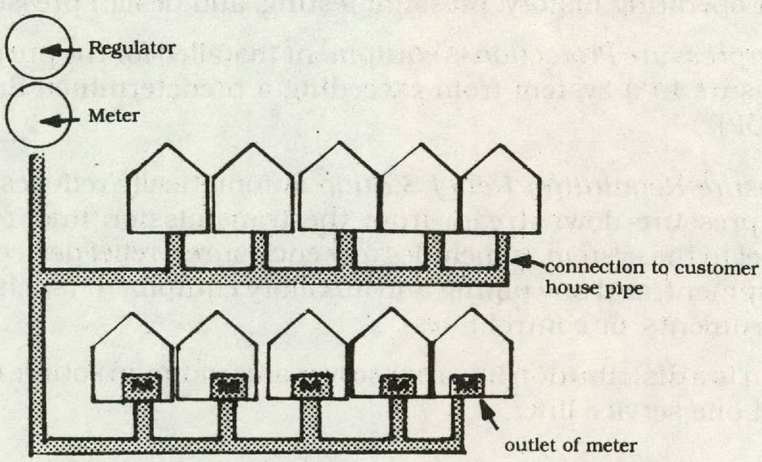


Figure 1

Master Meter System

Figure 1 is a typical master meter setup. The master meter operator for this complex is responsible for its design, construction, operation, and maintenance. In addition, the operator is responsible for the piping system from the outlet of the gas utility meter to the customer meter, or the connection to a customer's piping, whichever is farther downstream. All parts of the system must conform to the safety requirements as specified in 49 CFR 192, as well as those rules and regulations promulgated by the Railroad Commission of Texas.

B. System Definitions

1. *Service Line* is a gas distribution line that transports gas from a common source of supply to:

   a. A customer meter or the connection to a customer's piping, whichever is farther downstream.

   b. The connection to a customer's piping if there is no customer meter.

2. *Pipeline* means all parts of those physical facilities through which gas moves in transportation. This includes pipe, valves, and other items attached to pipe, metering stations, regulator stations, delivery stations, holders, fabricated assemblies, etc.

3. *Customer Meter* is a device that measures the volume of gas transferred from an operator to the customer.

4. *Service Regulator* is a device designed to reduce and limit the gas pressure to the customer.

5. *Riser* is the section of a service line that extends aboveground and is often near the wall of a building. Usually included with the riser is a shut-off valve, a regulator, and a unit meter.

6. *Shut-off Valve* is a valve installed for the purpose of shutting off the gas supply. The valve may be located ahead of the service regulator (see Section VI) or below ground at the curb (see Section VI).

7. *PSIG* means pounds per square inch gauge pressure (see Appendix H).

8. *MAOP* means maximum allowable operating pressure. This is established by past operating history, pressure testing, and design pressure.

9. *Overpressure Protection* is equipment installed for the purpose of preventing pressure in a system from exceeding a predetermined limit (based on the MAOP).

10. *Pressure Regulating/Relief Station* automatically reduces and controls the gas pressure downstream from the transmission line, main, or pressure vessel to the system. It includes any enclosures, relief devices, and ventilating equipment, and any piping and auxiliary equipment (such as valves, control instruments, or control lines).

11. *Main* is a distribution line that serves as a common source of supply for more than one service line.

C. Corrosion Definitions

Minimum safety standards for corrosion control are contained in Subpart I, 49 CFR 192. The criteria for cathodic protection and determination of measurements are contained in Appendix D, 49 CFR 192.

1. *Corrosion* is the deterioration of a metal pipe. The deterioration is caused by a reaction that takes place between metallic pipe and its surroundings. As a result, the pipe deteriorates and will eventually leak. This corrosion can be retarded with cathodic protection.

2. *Cathodic Protection* is a procedure by which underground metallic pipe is protected against corrosion.

The minimum requirements that should be included in your Operation and Maintenance (O&M) Plan are discussed in Appendix I of this booklet.

Some basic theories, concepts, and practical considerations for cathodic protection are contained in Appendix J.

D. Liquefied Petroleum Gas (LP-Gas or LPG) Definitions

LP-gas is a hydrocarbon having a vapor pressure not exceeding that allowed for commercial propane. It is predominantly one of, or a mixture of, the following hydrocarbons: propane, propylene, butane (normal butane or iso-butane), and butylene.

E. Class Locations

Based upon the number of buildings (units) **intended for human occupancy** within a prescribed area -- a class location number (1, 2, 3, or 4) is assigned. Hoop stress (defined in Appendix N) and maximum allowable operating pressure (MAOP) must not exceed the maximum for that class. (See Appendix N.)

The *class location unit* is an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline. The **class location** is determined by the number and type of buildings in the class location unit. (Each separate dwelling unit in a multiple dwelling unit is counted as one building.)

1. *Class 1* is a class location unit that has 10 or less buildings. Offshore is also considered to be Class 1.

2. *Class 2* is a class location unit that has between 11 and 45 buildings.

3. *Class 3:*

   a. Any class location unit that has 46 or more buildings intended for human occupancy; or

   b. An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

4. *Class 4* is a class location unit where buildings with four or more stories aboveground are prevalent.

F. **Definitions of Abbreviations**

The abbreviations of the organizations listed below are used repeatedly in this manual and in the gas industry.

1. *ANSI* — American National Standards Institute, 1430 Broadway, New York, New York 10018 (formerly the United States of American Standards Institute (USASI). All current standards issued by USASI and ASA have been redesignated as American National Standards and continue to be in effect.

2. *API* — American Petroleum Institute, 1271 Avenue of the Americas, New York, New York 10020; or 300 Corrigan Tower Building, Dallas, Texas 75201.

3. *ASME* — The American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, New York 10017.

4. *ASTM* — American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

5. *MSS* — Manufacturers Standardization Society of the Valve and Fittings Industry, 1815 North Fort Myer Dr., Room 913, Arlington, Virginia 22209.

6. *NACE* — National Association of Corrosion Engineers, P. O. Box 218340, Houston, Texas 77218.

7. *NFPA* — National Fire Protection Association, 60 Batterymarch Street, Boston, Massachusetts 02110.

8. *RRC* — Railroad Commission of Texas, Gas Utilities Division, Pipeline Safety Section, P. O. Drawer 12967, Capitol Station, Austin, Texas 78711-2967.

III. Reports and Plans Required by the Railroad Commission of Texas

Overview

This section discusses the operator's responsibility for reporting accidents and incidents by telephone and in writing* (within 30 days a completed Form DOT F 7100.1) to the RRC. Each operator is also required to develop and keep up-to-date a plan for inspecting, operating, and maintaining the gas system. In order to keep your plan up-to-date, you must keep records of all inspections, repairs, tests, etc. This section provides guidelines for these minimum requirements and tells how you can determine your capability for complying. You may need technical assistance in the more complex areas. This section will provide you with a basic knowledge of where to obtain technical assistance and what to expect from a technically qualified person.

A. **Accident Reporting (512/447-2171)** — operates 24 hours a day, seven days a week)

Natural gas distribution operators and petroleum gas operators are required to report certain accidents by telephone (16 TAC 7.70 Pipeline Safety). Report at the earliest practicable moment following discovery (as soon as possible, recommended within two hours) accidents that:

(1) Caused death or injury requiring hospitalization; or

(2) Resulted in gas ignition; or

(3) Caused property damage estimated at $5,000 or more (including the cost of gas lost); or

(4) Was significant in the judgment of the owner/operator even though it did not meet any of the other criteria. For instance, report a leak that requires evacuation of buildings or the general area or the rerouting of traffic.

NOTE: When in doubt — Call.

The telephone report of a serious incident or accident should include:

(1) Identity of reporting operator (including master meter operators);

(2) Name of individual reporting the incident;

(3) Phone number;

(4) The location of the incident: city, county, and street address;

(5) The time the incident occurred: date and hour;

(6) The number of fatalities and personal injuries, if any;

(7) Type and extent of property damage, including estimated monetary value; and

(8) All other significant facts, when available, such as:

(a) Part of system where leak or failure occurred (main or service);

(b) Part of system which leaked or failed (pipe, valve, fitting, drip regulator, tap connection, meter, other);

(c) Age of the part of the system which leaked or failed (installation date);

*Does not apply to master meter operators.

(d) Kind of material which leaked or failed (steel, plastic, cast iron, copper, ductile iron, wrought iron, other);

(e) Cause of leak or failure (corrosion, material failure, outside force, construction defect);

(f) Leak consequences (explosion, fire, secondary explosions or fires); and

(g) Nature of repair.

(See Appendix F for RRC Accident Report Form.)

B. Annual Reports

All natural gas operators with one or more customers, and all petroleum gas operators that supply 100 or more customers from a single source, are required to file an annual report. If you are a petroleum gas operator serving less than 100 customers from a single source, or a master meter operator, an annual report is not required.

The annual reports must be completed and submitted no later than March 15 for the preceding calendar year to:

Railroad Commission of Texas
Gas Utilities Division
Capitol Station — P. O. Drawer 12967
Austin, Texas 78711-2967

The Gas Utilities Division compiles the statistics from gas operators throughout the state. These statistics are used in research on pipeline safety. A set of instructions and a copy for the proper way to complete this form are in Appendix A. If you have not received a copy of the form (Annual Report for Calendar Year 19 ____ "Distribution System," Form DOT F 7100.1-1), or if you need assistance in filling out the form, call the RRC at (512) 463-7058.

C. Inspection and Maintenance (I&M) Plans

Originally, all natural gas operators and all petroleum gas operators with over 10 customers served by a single source were required by section 192.17 to file an I&M Plan. However, the Pipeline Safety Act was amended in 1979 and no longer requires I&M Plans to be filed with the federal government. However, 16 TAC 7.70 requires filing an I&M Plan in Texas. The RRC gives the operator the option of combining the I&M Plan with the Operating and Maintenance (O&M) Plan. The combined plans must be available and continually updated.

D. Combined Operating and Maintenance (O&M) and Inspection and Maintenance (I&M) Plans

All gas operators are required by section 192.603 to have a written O&M Plan. This plan is more detailed than the I&M Plan. The O&M Plan contains step-by-step procedures that must be followed to accomplish the required operational and maintenance procedures. The RRC recommends, for sake of simplicity and clarity, that operators of small gas systems make only one plan -- a plan in which the I&M Plan is made a part of the O&M Plan.

NOTE: In preparing your O&M Plan, you may save time by using as a guide the plan of a larger, established operator. Of course, that operator's permission may be required if any material is to be copied. And the plan would be of little or no value unless you carefully tailor it to meet the needs of your company.

In the combined I,O&M Plan, written procedures **must** include:

1. **Instructions for employees.** These must cover operating and maintenance procedures during normal operations and while making repairs (Section 192.605(a)).

2. **Emergency Procedures.** Specific procedures for facilities that present the greatest hazard to public safety, such as in an emergency or because of extraordinary construction or maintenance requirements (Section 192.605(c)).

3. **Uprating.** Procedures for uprating from a low-pressure distribution system to a higher pressure system, if contemplated (Section 192.605(d)). See Appendix C for details of a sample program.

4. **Line Markers.** O&M Plan must specify locations where you will mark pipe. Note the following requirements:

   a. Buried distribution pipelines. A line marker must be placed and maintained as close as practical over each buried distribution main at each crossing of a highway or street, railroad, and navigable waterway.

   Exclusions. Line markers are not required for buried distribution mains:

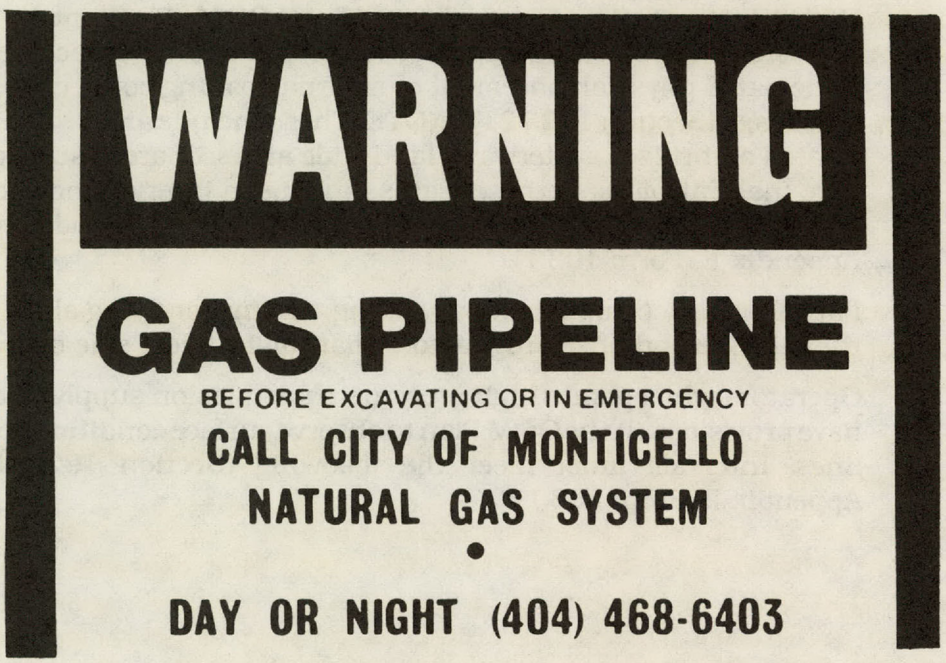


Figure 2

Line Marker

(1) Where it can be shown that the placing of a marker is impractical; or

(2) Where a program (such as a one-call system -- call before you dig) for preventing damage or interference with underground pipelines is established.

b. Distribution pipelines aboveground. Line markers must be placed and maintained along each section of a main that is located aboveground in an area accessible to the public.

c. Markers other than at navigable waterways. The following must be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one-inch high with one-quarter inch stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times (Section 192.707). (See Figure 2.)

d. Markers at navigable waterways. If your pipe crosses a waterway, call the U. S. Coast Guard to determine if it is navigable. If it is, mark it according to Section 192.707.

5. **Patrolling**

a. Distribution systems, patrolling. The I,O&M Plan must include provisions for patrolling mains located in places or on structures where anticipated physical movement or external loading could cause failure or leakage (Section 192.721). (NOTE: These include areas such as: pipe located on bridges, waterways, land slide areas, or areas susceptible to cave-ins.) Patrolling of these mains must be in intervals not exceeding four and a half months, but at least four times each calendar year (See Appendix E, Form 103.1).

Patrolling is accomplished by walking, driving, or flying along or near the pipeline and observing factors that might affect safe operation.

b. Operators who operate high pressure transmission supply lines must have provisions in the O&M Plan to observe surface conditions on those lines. Intervals must meet the following (Section 192.705) (See Appendix E, Form 103.1):

Maximum Interval Between Patrols

Class location of pipeline	At Hwy. & RR crossings	At all other places
1 & 2	7 1/2 months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4 1/2 months; but at least four times each calendar year.	7 1/2 months; but at least twice each calendar year.
4	4 1/2 months; but at least four times each calendar year.	4 1/2 months; but at least four times each calendar year.

6. **RRC Requirements for Leakage Surveys — Distribution Systems**

a. All business districts must have a gas detector leakage survey performed at least once each calender year.

b. Leakage surveys of the distribution system outside of the principal business areas must be made **as frequently as necessary**, but at intervals not exceeding five years.

c. Suggested Leakage Survey Schedule — Natural Gas & LP-Gas

(1) Flame Ionization (FI) and Combustible Gas Indicator (CGI) surveys in available openings must be conducted in the central business district and shopping centers once each calendar year at intervals not exceeding 15 months. Available openings include manholes (gas, water, sewer, electric, telephone), cracks in pavement, vaults or hollow walls in areas near gas pipelines. Areas surveyed should be recorded on a map of the distribution system. (See Figure 3.) All leaks discovered must be recorded. A sample form is in Appendix E, Form 102.1. (NOTE: For LP-gas systems, only CGI units are acceptable in conducting these surveys.)

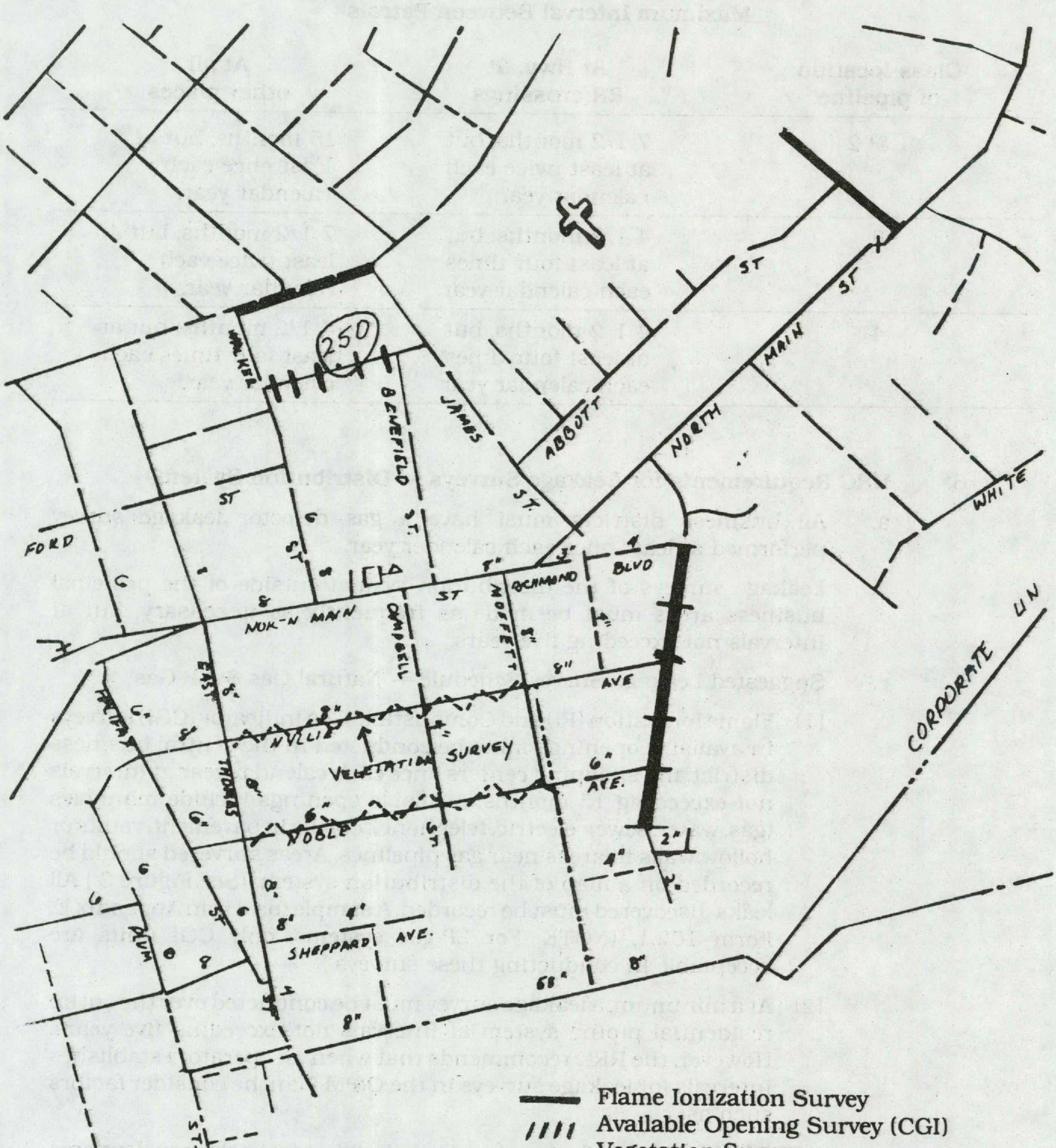
(2) At a minimum, a leakage survey must be conducted over the entire residential piping system at intervals not exceeding five years. However, the RRC recommends that when an operator establishes intervals for leakage surveys in the O&M Plan, he consider factors such as:

(a) Material make up of system. Certain materials may develop a higher than average leakage rate; for example, unprotected bare steel, PVC plastic pipe, extruded tubing, cast iron with lead joints, and coated steel pipe not under cathodic protection.

(b) Age of pipe (over 20 years).

(c) Operating pressures (over 60 psig).

(d) Pipe having a previous record of excessive leakage history, especially corrosion leakage history or joint leakage history.



Sample Distribution Map Showing How Leak Surveys Are Recorded

Figure 3

(e) Pipe located near buildings, especially schools, hospitals, or other buildings having a high concentration of people. (See Appendix E, Form 104.1.)

(f) Pipe located in areas of construction, blasting, or heavy traffic. Pipe located in crawl spaces under apartment buildings or mobile homes.

(g) When conducting these surveys, it is a good policy to check for leaks near the gas pipe entrance, both inside and outside of buildings.

Based on the above factors, an operator should designate areas in the system that require more frequent surveys. Annual leakage surveys conducted with an FI or CGI may be appropriate if you have one or more of the above conditions. LP-gas operators must use a CGI unit when conducting leakage surveys.

(3) When a leak is discovered, it must be investigated to determine if a hazard exists. If a hazardous condition is found, **immediate action must be taken.** The operator must protect life and property until the conditions are no longer hazardous. All leaks found must be classified. As a guide for classifying leaks, you may want to include the ASME Leak Classification Guide and Action Criteria in the O&M Plan. This guide is contained in Appendix D.

(4) Annually, a map of the distribution system should be marked or color coded to show leak surveys conducted and the areas tested. Indicate the approximate location of each leak found. Notes may be marked in accordance with Figure 3. (NOTE: See Appendix D for details about gas detection equipment and recommended practices to follow when conducting a leakage survey.) For sample records of leakage surveys, see Appendix E, Form 102.

***7. Minimum Requirements for Leakage Surveys — Transmission Lines**

a. Each operator of a transmission line shall provide for periodic leakage surveys of the line in the O&M Plan.

b. Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. Leak detector equipment must be used to conduct leakage surveys over transmission lines carrying nonodorized gas:

(1) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and

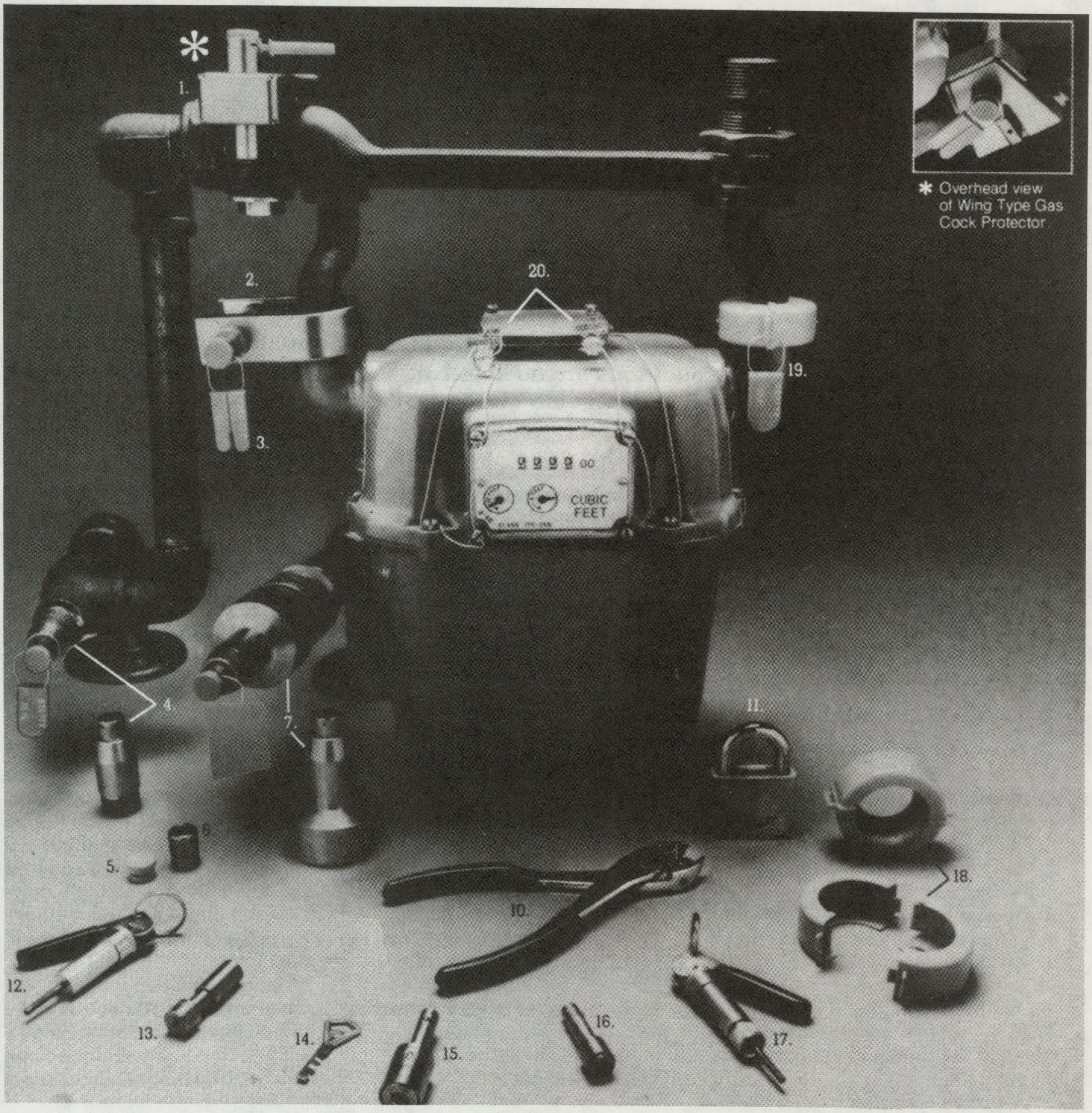
(2) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.

For sample records see Appendix E, Forms 102.1 and 103.1.

*Does not apply to master meter operators.

8. **Testing Prior to Reinstating Service Line**

The O&M Plan must contain a provision for testing, in the same manner as a new service line, each service line that is disconnected from a main (Section 192.725) (See Section V and Appendix O of this guideline). For sample record form, see Appendix E, Form 113.1.



Various Locking Devices

Figure 4

9. **Abandonment**

a. The O&M Plan must include provisions for shut down, abandonment, or inactivation of facilities.

(1) When a gas main or service line is abandoned, it shall be physically disconnected from the piping system. The open ends shall be effectively sealed. In addition, the operator shall determine the necessity of purging the line, taking into consideration the location and size of the main or service. As a recommendation, pipe four inches and larger should be purged.

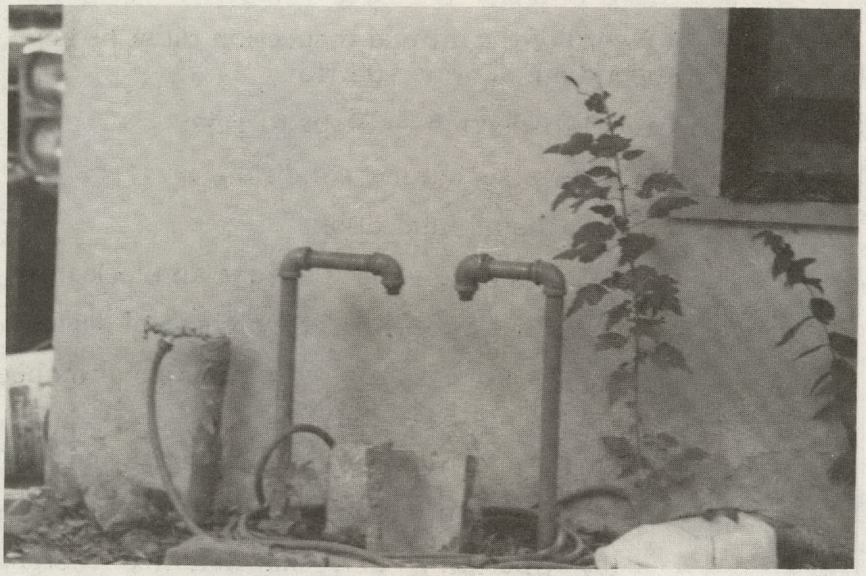
(2) In cases where the main together with all the service lines connected to it are abandoned, the customers service line(s) ends must be capped. Also, the main must be sealed at both ends.

(3) Records shall be kept on all facilities abandoned. This includes: location, date, and method of abandoning the facility.

b. Inactivation of Service

When service to a customer is discontinued, one of the following must be done:

(1) The valve must be closed to prevent flow of gas to the customer. This valve must have a lock or some other means to prevent unauthorized people from opening the valve. There are numberous locking devices designed for this purpose. (Figure 4.)



Vacant Meter Loop Properly Plugged

Figure 5

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or the meter assembly.

(3) The customers piping must be physically disconnected from the gas supply and the open ends sealed (Section 192.727) (See Figure 5).

10. **Regulator Stations — Inspection and Testing**

If regulator stations are a part of your system, provisions must be made in the O&M Plan to inspect and test both regulators and relief devices.

NOTE: Many **master meter systems** will not have a regulating station. A simple definition of a **regulator station** is any pressure limiting device or regulator other than customer service regulator(s) installed in a gas system to control gas pressure. Simply put, if an operator does not regulate (lower) the gas pressure from the local gas utility, or LP-gas tank, except at customer service regulator, this section and Section II do not apply.

a. Inspect at least once each calendar year, at intervals not exceeding 15 months, to determine that they are:

(1) Mechanically in good condition.

(2) Adequate from the standpoint of capacity and reliability of operation.

(3) Set to function at the correct pressure.

(4) Properly installed and protected from vehicular traffic, dirt, liquids, icing, or other conditions that might prevent proper operation (Section 192.739).

A record of the annual inspection must be kept. Sample forms are in Appendix E., Forms 105.1(a).

b. Annual Inspection — Steps to Take

(1) Check mechanical condition.

(a) Visual inspection.

(b) Operation check (stroke and lock up).

(c) Check pressure at which relief device and regulator is set.

(d) Use bypass piping if available and check operating limits of primary regulator.

(2) Observe for these problem areas.

(a) Distribution system pressure appears low.

(b) Operating and maintenance history of station is not satisfactory.

(c) Gas supply is dirty.

(d) Back-up safety devices are not operational.

If you have any of these problems, you may need technical help. Regulator disassembly or station redesign may be necessary. CAUTION: DO NOT DISASSEMBLE REGULATORS UNLESS YOU

Figure 6

Example of a Well Protected
District Regulator Station

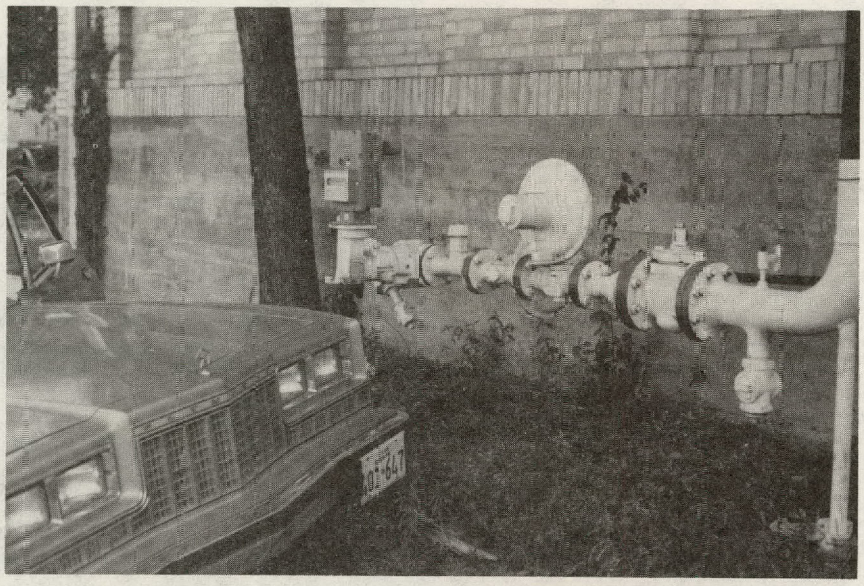
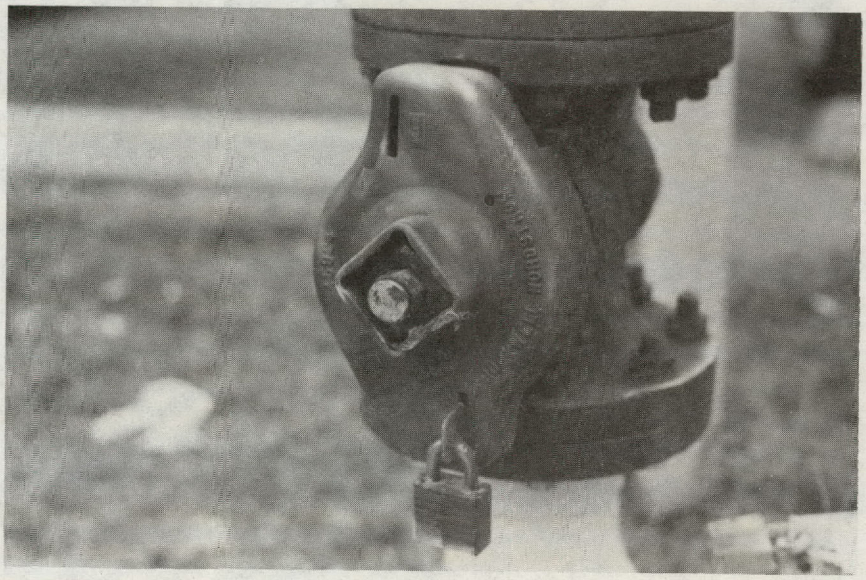


Figure 7

Example of a Poorly Protected
District Regulator Station

Figure 8

Stop valve (below relief valve) in a regulator station must be **locked** in an **open** position.



See 49 CFR 192.199(h) for specific requirements.

HAVE BEEN THOROUGHLY TRAINED (by the regulator manufacturer, its area representative, or operator consultant) in the proper steps to take in disassembly and reassembly of a particular regulator.

The O&M Plan should include the names and telephone numbers of the people to contact for any situation in which outside assistance is required.

Always keep and use the manufacturer's manual, diagrams, and maintenance procedures for each particular regulator. Appendix H contains some basic concepts about pressure regulation and relief devices.

11. **Testing of Relief Devices at Regulator Stations**

Provisions must be made in the plan for testing relief devices for capacity, if feasible. If not feasible, the calculation of capacity must be reviewed in intervals not exceeding one year. You must maintain a copy of this calculation.

The test must show that the relief valve capacity is adequate for the system's MAOP.

The regulations recognize two types of distribution systems — low pressure and high pressure.

a. **Low Pressure**

Relief capacity for low pressure systems must protect the customer's equipment from overpressuring. The gas pressure in the main is approximately the same as the pressure provided the customer (usually seven to eleven inches water column (w.c.), 4-6 oz. per square inch).

b. **High Pressure**

In pipelines and distribution systems, the relief device must be set according to the system's MAOP.

(1) If the MAOP is 60 psig or more, the pressure may not exceed MAOP plus 10 percent (or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower) (Hoop stress and SMYS are defined in Appendix N.);

(2) If the MAOP is 12 psig or more, but less than 60 psig, the pressure may not exceed the MAOP plus six psig; or

(3) If the MAOP is less than 12 psig, the pressure may not exceed the MAOP plus 50 percent.

If testing reveals that the relief devices do not have adequate capacity, then a new or additional device must be installed.

c. **Capacity and Reliability**

Capacity must be checked **one time each year** for each MAOP in a system. (You must ensure that the MAOP will not be exceeded downstream of the regulator station if the worst condition occurred

—regulator fails when fully opened) Most small systems have only one MAOP for all piping in the distribution system.

In other words, a combination of minimum customer usage and relief capacity must ensure that MAOP will not be exceeded (except to extent described).

To comply with this requirement, most small systems have had a consultant analyze their gas system and make the required relief valve capacity calculations. If the analysis proved that the relief valve had adequate capacity, a copy of this calculation must be kept on file by the operator. The calculation of capacity need only be reviewed and initialed on an annual basis if there has been no system change (e.g., change made to upstream regulators, such as different pressure, orifice, or type of regulator). If a change is made, the new relief valve capacity calculations must be made and kept on file (Section 192.743). It is a good idea to keep this capacity calculation with your annual inspection record. Sample forms in Appendix E, Forms 105.1 and 105.1(a).

d. **Important Facts to Remember**

(1) If an operator is designing a new regulating station or replacing or making a major change to an existing station, the station must meet the design requirements contained in Sections 192.195, 192.199, 192.201, and 192.203.

(2) Existing pressure limiting and regulating stations must be inspected and tested for operating condition at intervals not exceeding 15 months, but at least once each calendar year (Sections 192.739 and 192.743).

(3) If the annual inspection shows the existing relief device has insufficient capacity, you must replace or add a relief device to provide the required capacity.

(4) The stations should be protected from damage from outside forces (cars, trucks, falling objects).

For other considerations for relief and regulating stations, see Appendix H.

12. Accidental Ignition of Gas

Provisions must be made in the O&M Plan to prevent the accidental ignition of gas. Gas alone is not explosive, but when it is mixed with air, it can explode with tremendous force, especially in a confined area. Every precaution should be taken to prevent any such explosive mixture from igniting (Section 192.751).

13. Key Valves Maintenance

The O&M Plan must have provisions to maintain key valves in the distribution system at intervals not exceeding 15 months, but at least once each calendar year. Records of this inspection and maintenance must be retained (Section 192.747). See Appendix E, Record Forms 106.1 and 107.1.

Key valves are those valves needed to shut down a system or part of a system in case of an emergency. For small LP-gas and master meter systems this may involve only one or two valves. Operators most often do not consider curb valves or service valves as key valves (requiring annual maintenance check).

Steps to take in determining key valves:

a. Determine location of all valves on mains. (Suggest plot on system map and detail sketches with dimensions to other structures.)

b. Determine key valve by the degree of importance to system operation. Consider the following:

(1) Control valve(s) at each pressure regulator station.

(2) Primary feed(s) to business districts.

(3) All single valves on mains within a business district.

c. Select key valves according to the following criteria:

(1) Reasonable for sectionalizing plan.

(a) Number of customers that can be turned on or off in a 24-hour period.

(b) System pressure.

(c) Volume of gas that could escape.

(d) Environment (near school, soil condition, construction activity, etc.)

(e) Response time/valve accessibility.

(2) Necessity — based on system operating history

(a) Excessive leakage.

(b) Corrosion problem.

(c) Pipe breakage problem.

(d) Pressure problem.

NOTE: For operators with transmission supply lines. Each transmission line valve that is selected for emergency use must be inspected and **partially operated** at intervals not exceeding 15 months, but at least once each calendar year (Section 192.745). For record form, see Appendix E, Forms 106.1 and 107.1.

14. Cast Iron Pipes

Operators with cast iron pipe must have the following provisions in the O&M Plan:

a. Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psig or more must be sealed with a mechanical leak clamp, material or device which:

(1) Does not reduce the flexibility of the joint;

(2) Permanently bonds, either chemically, mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(3) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of Sections 192.53(a) and (b), and 192.143.

b. Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 psig and is exposed for any reason, must be sealed by a means other than caulking (Section 192.753) (B).

c. Protecting Cast Iron Pipelines (Section 192.755)

When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed, that segment of the pipeline must be protected as necessary. Examples are:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Excavations near the pipeline; or

(5) Other foreseeable outside forces that may subject that segment of the pipeline to bending stress.

15. **Odorization of Gas**

a. Natural gas operators and master meter operators who receive gas already odorized by their supplier must make provisions in their O&M Plan for analyzing odor.

Operators must verify that a person with a normal sense of smell can readily detect the odor with gas in air at **1/5 of the lower explosive limit.** To be in compliance:

(1) Have the gas company that sells you the gas verify by either records or tests, that the gas being sold to you meets the above criteria.

(2) Have a qualified person or the gas utility company or transmission company run an odorometer test of the gas in system on a quarterly basis.

(3) Run periodic 'sniff tests' for the gas in the system. The sniff test can be accomplished during meter change outs or other maintenance work. Make sure you **keep records** of these tests, including dates, names, and locations (See Form 108.1) for at least two (2) years.

NOTE: These tests should be run at the **ends of the system,** when possible.

b. LP-Gas operators should make provisions in their O&M Plan for the following:

(1) Verify that the odorant in the gas purchased meets the requirements in Appendix K. This can often be done by retaining

copies of the bills of lading from the supplier of gas as evidence of odorant.

(2) Have provisions in your O&M Plan for periodic "sniff tests" for gas in system. A sniff test can be performed during work, such as meter change outs, or other maintenance work. Make sure you **keep records** of these tests, including dates, names, and locations.

NOTE: See Appendix K for specific RRC reporting requirements.

c. Operators who odorize their own gas must ensure that there is enough odorant in the gas. The odor must be readily detectable by a person with a normal sense of smell when gas is present in air at a concentration of 1/5 of the lower explosive limit. Operators must follow these basic rules (Section 192.625):

(1) Odorize all gas in distribution mains and service lines.

(2) Odorize all gas in transmission supply lines running from the transmission line sales point to the city town border station in Class 3 or 4 locations. If 50 percent of the length of the line downstream from that location is in a Class 1 or 2 location, you may not have to odorize this line.

(a) Any service line that is directly tied into a nonodorized transmission supply line must be individually odorized.

(b) The RRC recommends that small natural gas operators odorize at the point where they purchase gas from the gas supplier.

(3) Specify in the O&M Plan the type of odorant (dilute or concentrate) used in the system.

(4) Specify in the O&M Plan the amount of odorant injected per MMcf of gas.

(a) The odorant and its product of combustion cannot be toxic to humans or harmful to components that make up the piping system.

(b) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(5) Include in the O&M Plan any maintenance procedures recommended by the odorizer's manufacturer. Odorization equipment must introduce the odorant without wide variations in the level of odorant.

(6) Sample periodically. The procedure must be part of your written O&M Plan. Include:

(a) Periodic testing of your odorant injection rate.

(b) Testing at various locations, including outer extremities of the pipeline system. Verify that the odor is readily detectable when natural gas is present in concentrations in air of one percent or less.

(7) Maintain records of injection rate and odor sampling, as required by the RRC. For sample record see 108.3.

(Appendix K contains some diagrams of odorization equipment; lists further guidelines on operating, maintenance, and design.

16. **Corrosion Control Requirements**

Provisions must be made in your O&M Plan for corrosion control. Your plan must include the following procedures for:

a. Implementing a corrosion control program with procedures for design, installation, operation and maintenance of cathodic protection systems. This must be under the direction of a person qualified by experience and training in pipeline corrosion control methods.

b. Ensuring cathodic protection of pipe installed after July 31, 1971. This pipe must be coated and cathodically protected in its entirety (unless a non-corrosive environment can be proven by comprehensive testing).

c. Ensuring cathodic protection of pipe installed before August 1, 1971.

(1) Transmission lines with an effective external coating must be protected in its entirety.

(2) The following must be cathodically protected in areas where active corrosion is found. Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

(a) Bare or ineffectively coated transmission lines.

(b) Bare or coated pipes at compressor, regulator, or measuring stations.

(c) Bare or coated distribution lines.

NOTE: Areas of active corrosion shall be determined by electrical survey or where an electrical survey is impractical the study of corrosion and leak history records, by leak detection survey or by other effective means documented by records and data.

d. Examining buried pipe when exposed. This should be a physical examination for evidence of external corrosion or if the coating is deteriorating.

e. Monitoring for the effectiveness of cathodic protection facilities to be done at least annually with intervals not to exceed 15 months.

f. Inspecting rectifiers, for proper operation, at least six times each calendar year with intervals not exceeding 2 1/2 months.

g. Reevaluate unprotected pipelines at intervals not exceeding 3 years and cathodically protect areas found with active corrosion. If leak detection surveys are used, the frequency of these surveys must be increased to control conditions and to monitor the rate of corrosion.

h. Ensuring that each buried pipeline is electrically isolated from other underground metallic structures.

i. Have in effect a continuing program to minimize the effects of stray or interference currents. Each critical interference bond installed shall be electrically checked for proper operation six times each calendar year with intervals not exceeding 2 1/2 months.

j. Ensuring that whenever any pipe is removed from a pipeline for any reason that the internal surface is inspected for evidence of corrosion. If corrosive gas is being transported, the pipe must be monitored or internally inspected twice each calendar year not exceeding 7 1/2 months by inspecting coupons or other suitable means.

k. Checking atmospheric corrosion on aboveground pipe at intervals not exceeding three years.

l. Maintaining records and maps to show location of cathodically protected piping, cathodic protection facilities and records of all tests, surveys, and inspections that demonstrate the adequacy of the facilities or the lack of a corrosive environment.

Summary

Any time it is determined that a length of pipe is to be cathodically protected, no matter what method is used, it **must** meet one of the five criteria expressed in Appendix D of 49 CFR Part 192. This length must then be mapped, electrically isolated and have enough test points installed for proper monitoring.

Record keeping can be your most useful tool in operating and maintaining a corrosion control program. Maps and records of the facilities, anode installations, insulating couplings, interference bonds, corrosion leak maps, and records of all monitoring and inspections are helpful in determining the adequacy of your corrosion control program.

17. Leak Repairs — Construction

The O&M Plan must contain provisions for leak repair and construction. These procedures will vary by system. Section V and Appendix O of this guideline give some basic procedures and concepts that should be covered.

18. Emergency Plans (Section 192.615)

All operators are required to have a written emergency plan. See Appendix F for sample of an Emergency Plan.

19. Helpful Hints

a. Place the "General Maintenance Schedule Chart" (Appendix E, page 82) in a visible location as a reminder of the minimum safety requirements.

b. Use the "Master Chart" (Appendix E), for the required record keeping of operation and maintenance work for your gas system.

NOTES

IV. Materials Qualified for Use in Gas Systems

Overview

The minimum safety standards list many different materials qualified for gas service. Material and specifications listed in this guideline are those most commonly used in gas distribution systems installed in the early 1980s. Not all materials or specifications listed in the minimum standards are included in this section.

When purchasing material to be used in a gas system, it is extremely important to check the **marking** of the material. The marking on the material will help identify if the material is qualified for gas service.

This section will stress the most common specifications and standards used by manufacturers for materials that are commonly used in gas distribution systems. When selecting a piping system, it is essential to know that piping systems consist of pipe and fittings, not just pipe. Therefore, an operator must select materials that are compatible with each other.

A. Qualification of Pipe

Only steel and plastic pipe specifications are included in this guideline. For other pipe qualified for gas service, see 49 CFR 192.

Listed below are pipe specifications. Numbers in parentheses indicate applicable editions.

API 5L—Steel pipe (1985).
ASTM A53—Steel pipe (1979).
ASTM A106—Steel pipe (1979).
ASTM A134—Steel pipe (1974).
ASTM A135—Steel pipe (1979).
ASTM A139—Steel pipe (1974).
ASTM A211—Steel and iron pipe (1975).
ASTM A333—Steel pipe (1979).
ASTM A377—Cast iron pipe (1979).
ASTM A381—Steel pipe (1979).
ASTM A539—Steel tubing (1979).
ASTM Specification A671—Steel pipe (1977)
ASTM Specification A672—Steel pipe (1979).
ASTM Specification A691—Steel pipe (1979).
ASTM B42—Copper pipe (1980).
ASTM B68—Copper tubing (1980).
ASTM B75—Copper tubing (1980).
ASTM B88—Copper tubing (1980).
ASTM B251—Copper pipe and tubing—(1976).
ASTM D2513—Thermoplastic pipe and tubing—(1981).
ASTM D2517—Thermosetting plastic pipe and tubing—(1973).
ANSI A21.52—Ductile iron pipe (1971).

1. Steel Pipe

The following table can be used for selecting the proper nominal wall thickness for steel pipe for use in a gas distribution system (dimensions in inches).

TABLE I

Nominal Pipe Size	Outside Diameter	Standard (Schedule 40) Wall Thickness	Min. Wall Thickness After Threading
1/8	0.404	0.068	0.065
1/4	0.540	0.088	0.065
3/8	0.675	0.091	0.065
1/2	0.840	0.109	0.065
3/4	1.050	0.113	0.065
1	1.315	0.133	0.065
1 1/4	1.660	0.140	0.065
1 1/2	1.900	0.145	0.065
2	2.375	0.154	0.075
3	3.500	0.216	0.098
3 1/2	4.000	0.226	0.108
4	4.500	0.237	0.116
5	5.563	0.258	0.125
6	6.625	0.280	0.156
8	8.625	0.322	0.172
10	10.750	0.365	0.188
12	12.750	0.406	0.203

All the new steel pipe manufactured under the above specifications with the above wall thicknesses have design pressures up to at least 152 psig. The actual MAOP of new or replacement pipe in a gas system depends upon the pressure test performed by the operator or his contractor on the piping system before it is put in service. It is also recommended that threaded pipe not be installed underground.

2. Plastic Pipe

When purchasing polyethylene (PE) plastic pipe, it is required that the pipe be marked ASTM D2513. Plastic pipe with this marking is suitable for gas service. Fiberglass epoxy plastic pipe marked ASTM D2517 is also qualified for gas service. However, ASTM D2517 is no longer installed by most gas companies because of the cost.

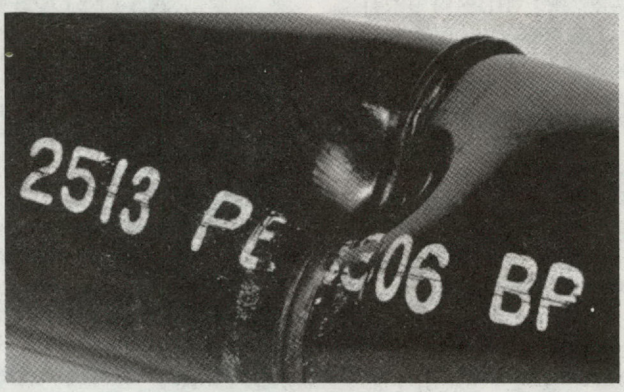
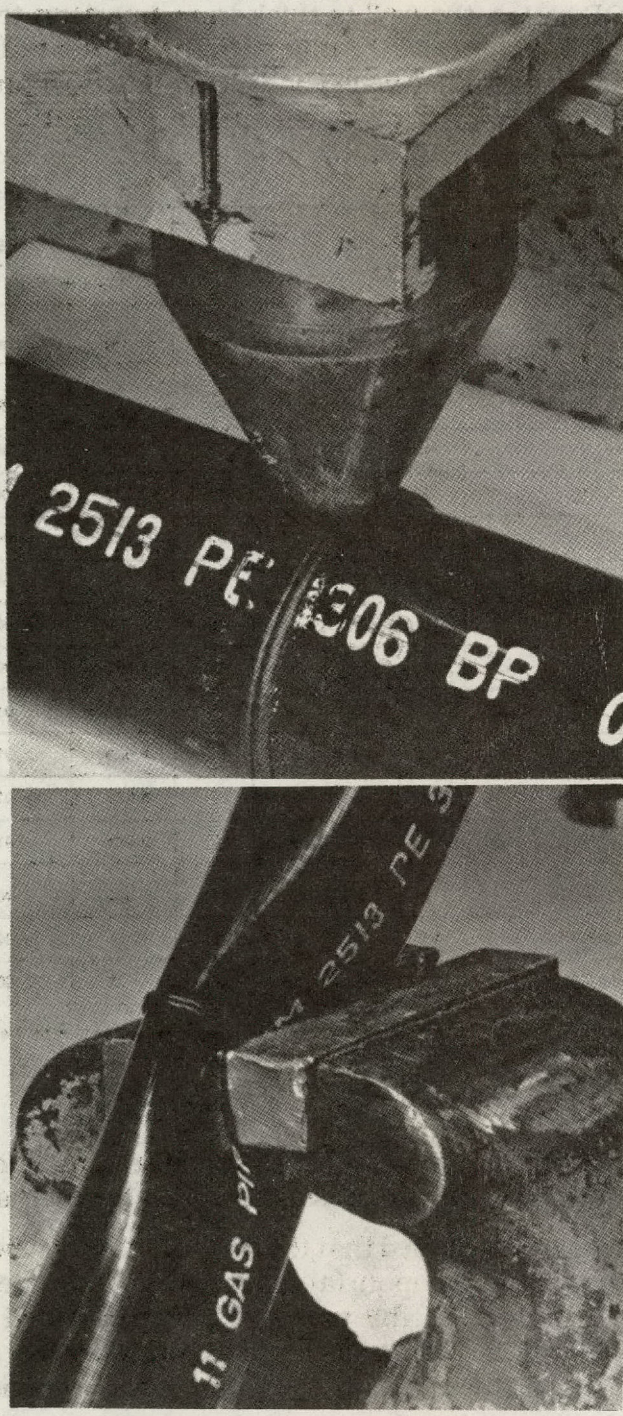


Figure 9

In recent years, the vast majority of natural gas companies have been installing ASTM D2513, PE Pipe. Some of the reasons PE pipe is being installed is its flexibility, good joining characteristics, durability, ease of installation, and costs. The PE designations most often used are PE 2306, PE 3306, PE 3406, and PE 3408. For examples of proper PE markings, see Figure 9A.



Pipe Marked ASTM D2513

Figure 9A

Most PE pipe manufacturers subscribe to the Standard Dimension Ratio (SDR) method of rating pressure piping. The SDR is the ratio of pipe diameter to wall thickness. An SDR 11 means the outside diameter (O.D.) of the pipe is eleven times the thickness of the wall.

For high SDR ratios, the pipe wall is thin in comparison to the pipe O.D. For low SDR ratios, the wall is thick in comparison to the pipe O.D. Given two pipes of the same O.D., the pipe with the thicker wall will be stronger than the one with the thinner wall. High SDRs have low pressure ratings; low SDRs have high pressure ratings because of the relative wall thickness.

Design Pressure Rating—PSIG At Various Temperatures					DIMENSIONS (Inches)			
					Outside Diam.		Wall Thickness	
Nominal Size	SDR[†]	Up to 100°F	120°F	140°F	Average	Tolerance	Minimum	Tolerance
Iron Pipe Size ½"	9.3	96	76	61	.840	±.004	.090	+.020 −.000
¾"	11	79	63	50	1.050	±.004	.095	+.021 −.000
1"	11	79	63	50	1.315	±.005	.119	+.026 −.000
1¼"	10	88	71	56	1.660	±.005	.166	+.026 −.000
2"	11	80	64	51	2.375	±.006	.216	+.026 −.000
3"	11.5	76	61	49	3.500	±.008	.307	+.035 −.000
4"	11.5	76	61	49	4.500	±.009	.395	+.040 −.000
6"	21	40	32	25	6.625	±.011	.316	+.038 −.000
6"	11.5	76	61	49	6.625	±.011	.581	+.069 −.000
8"	21	40	32	25	8.625	±.013	.411	+.049 −.000
8"	11	80	64	51	8.625	±.013	.785	+.094 −.000
Copper Tubing Size ½" (⅝" OD)	7	100	100	86	.625	±.004	.090	+.006 −.000
1" (1⅛" OD)	11.5	77	61	49	1.125	±.005	.099	+.008 −.000
1" (1⅛" OD)	12.5	69	55	44	1.125	±.005	.090	+.008 −.000

† Standard Dimension Ratio is calculated by dividing the average OD of the pipe by the minimum wall thickness in inches, as described in ASTM D-2513, par. 3.3.

This table is intended to be a guideline. The operator should check the manufacturer's specific pressure ratings for each specific pipe.

Operators are cautioned that the actual MAOP of new or replacement pipe in a gas system depends upon: (a) design pressure of the pipe and components in the system; and (b) the pressure test performed by the operator or his contractor on the piping system. This pressure test must be made before the system is put in service. (See Section V and Appendix O of this guideline.)

PE pipe may be joined by either a heat fusion method (butt or socket) or by a mechanical coupling. Both joining procedures and personnel making joints must be **properly qualified.** See Section V.

PE pipe that is not encased must have a minimum wall thickness of 0.090 inches. However, pipe with an outside diameter of 0.875 (3/4") or less may have a minimum wall thickness of 0.062.

Acrylonitrite-butadiene-styrene (ABS), Cellulose acetate buytrate (CAB), Polybutylene (PB), and Polyvinyl chloride (PVC) are also qualified for **natural — not LP —** gas service if the pipe has the **ASTM D2513 marking on it.** However, most natural gas companies no longer install these types of gas pipes because they believe that PE pipe has superior characteristics.

For additional sources of information about plastic pipe, see Section VII of this guideline. Master meter operators may be able to obtain information about local suppliers of plastic gas pipe from the local gas utilities. For a list of manufacturers making pipe according to ASTM D2513, see Appendix G.

3. Pipe For LP-Gas Systems

a. The polyethylene plastic pipe, tubing, and fittings must be only those specific types designated as PE 2306, PE 3306, PE 3406, or PE 3408 and must meet the appropriate requirements of ASTM D2513.

b. Polyethylene piping should be used only in underground commercial propane gas distribution systems. These systems must operate at internal pressures and temperatures so that condensation **will not occur.**

c. **For LP-gas applications, the maximum operating pressure is 30 psig.** LP-gas has a higher condensation temperature than does natural gas; this maximum pressure is recommended to ensure that plastic pipe is not subjected to excessive exposure to LP-gas liquids. PE pipe manufactured according to ASTM D2513 is the only plastic pipe qualified for use in petroleum gas systems.

B. Metal Valves

1. Minimum Requirements

Each valve must meet the minimum requirements, or the equivalent, of API 6A, API 6D, MSS SP-70, MSS SP-71, or MSS SP-78. A valve may not be used under operating conditions that exceed the applicable pressure - temperature ratings contained in those standards. The valve will be stamped with either the class (ANSI) or the maximum working pressure rating (psig). Never operate valves at pressures exceeding their rating.

2. Explanation of Some Common (Metal) Valve Markings

a. The class or ANSI ratings on steel valves are ratings which specify the maximum working pressure for flanged-end and welded-end gate-plug, ball and check valves. See the following table:

Class Rating/Maximum Working Pressure

Class (ANSI)	150	300	400	600	900	1500	2500
Maximum Working Pressure Rating PSIG	275	720	960	1440	2160	3600	6000

The maximum working ratings are applicable at temperatures from -20° F to 100° F.

Metal valves will often be stamped with the symbols "WOG." This means that they are suitable for service for water, oil, or gas. Sometimes just the letter "G" (for gas) appears.

The manufacturer's name or trademark will also be included on a valve. Operators should maintain manufacturers' manuals which include installation, operation, and maintenance procedures for each valve in the gas system. These manuals and procedures should be incorporated into the O&M Plan.

C. Plastic Valves

Plastic valves suitable for gas service should comply with industry standard ANSI B16.40, "Manually Operated Thermoplastic Valves in Gas Distribution Systems." The valves must be compatible with the plastic pipe used in gas systems. It is important that operators of small systems find a supplier who is knowledgeable in the gas piping field before buying plastic valves. This supplier information can be obtained from trade journals, local gas associations (state or regional), or local gas utilities. See Section VII.

For plastic fittings made of PVC or ABS plastic, see Section 192.191.

D. Flanges and Flange Accessories (Metal)

Each flange or flange accessory must meet the minimum requirements of ANSI B16.5, MSS SP-44, or ANSI B16.24.

Operators of small systems should verify that metal flanges purchased for their systems meet the above requirements. This can be done by checking the markings on the flanges. These markings are similar to those on valves.

For plastic fittings made of PVC or ABS plastic, see Section 192.191.

E. Regulators and Overpressure Equipment

There are many different manufacturer models of gas regulators and overpressure equipment (relief valves) available for gas systems.

Regulators and overpressure equipment must be properly sized so that overpressure or low pressure conditions do not occur on the gas system. Manufacturers of gas regulators and relief valves have manuals which contain formulas and charts for each of their specific models or types of equipment. These charts and formulas are necessary to properly size regulators and relief valves. Operators who do not have a technical background may have to rely on a consultant or the manufacturer's representative to properly size the equipment. A qualified person must install the system. Section VII of this guideline also provides a listing of organizations and publications that may be helpful in selecting the proper equipment.

It is important to obtain from the regulator or relief valve manufacturer a set of operation and maintenance instructions for each individual type of regulator and relief valve in the system. Normally, the manufacturer publishes a manual with these instructions in it. The instructions should be incorporated into the O&M Plan. Appendix H gives some basic concepts on pressure regulation.

F. Other Equipment

A gas operator will need additional equipment to operate a gas system. The names of some of the manufacturers and suppliers of this equipment (such as cathodic protection monitoring equipment, pipe locators, and gas leak detection equipment) are in Section VII of this guideline. Figure 10 illustrates two kinds of pipe locators. An illustration of a pipe-to-soil meter is contained in Appendix J. Gas leak detection equipment is covered in Appendix D. The various pipeline journals listed are an excellent source of information on equipment, current issues, suppliers, etc. The local gas utility or gas association may also be able to provide help.

G. Other Comments About Material Selection

1. Pre-planning

It is important for an operator to know the material make-up and operating pressure of an existing system. Based on this knowledge, the operator should develop or have a consultant develop, a list of approved material for use in construction and repair of the gas piping system. Installation procedures should be included for each specific type of material approved for the system. This can be accomplished by including or referencing manufacturer's gas product installation manuals in the O&M Plan.

2. Storage of Plastic Pipe

At no time should the loading of the pipe cause the pipe section to lose its round shape. Plastic pipe and tubing should be stored so as to minimize the possibility of the material being damaged. It could be damaged by crushing, piercing, or extended exposure to direct sunlight.

NOTES

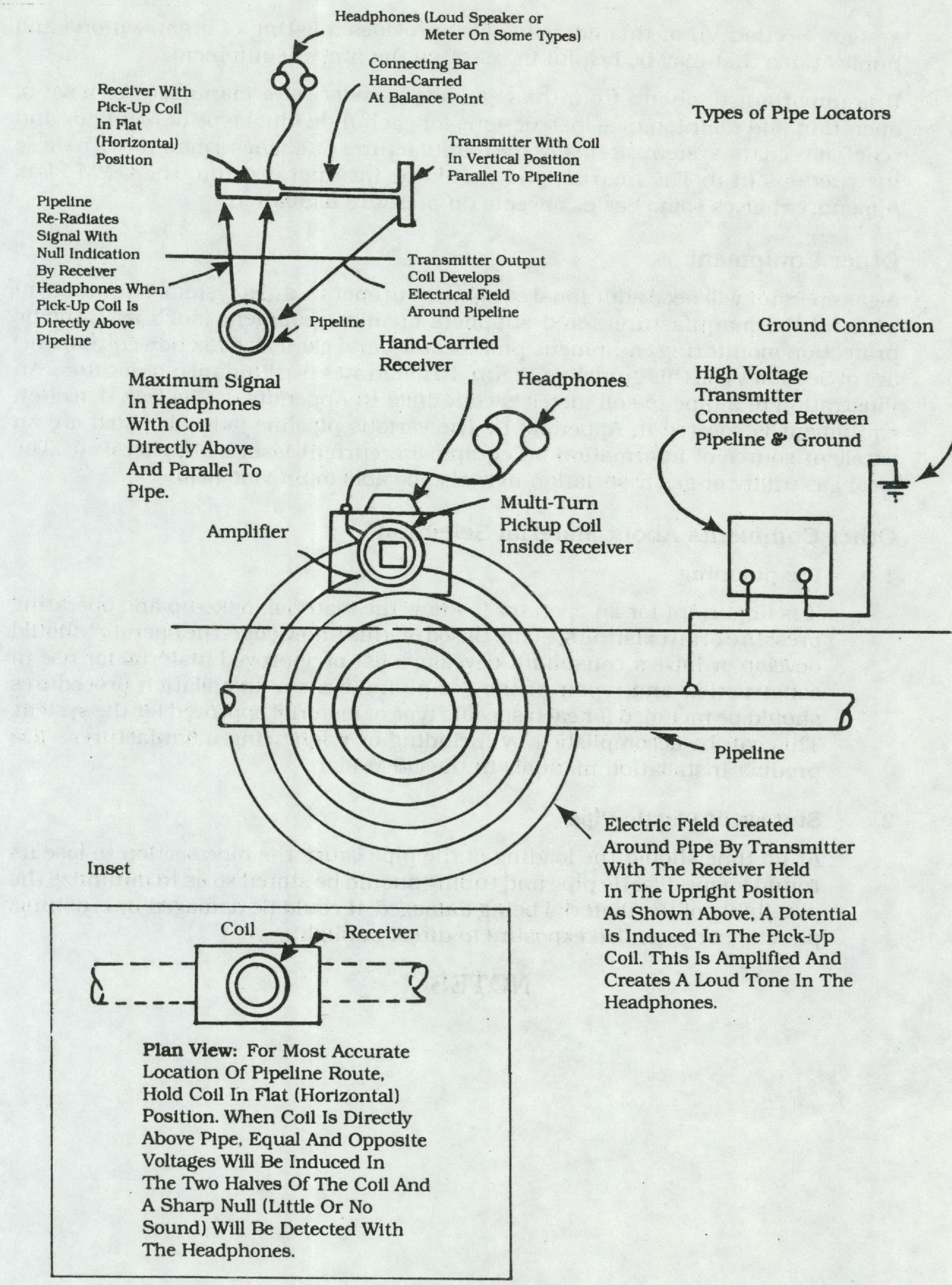

Headphones (Loud Speaker or Meter On Some Types)
Connecting Bar Hand-Carried At Balance Point
Receiver With Pick-Up Coil In Flat (Horizontal) Position
Transmitter With Coil In Vertical Position Parallel To Pipeline
Pipeline Re-Radiates Signal With Null Indication By Receiver Headphones When Pick-Up Coil Is Directly Above Pipeline
Transmitter Output Coil Develops Electrical Field Around Pipeline
Pipeline
Types of Pipe Locators
Ground Connection
Hand-Carried Receiver
Headphones
Maximum Signal In Headphones With Coil Directly Above And Parallel To Pipe.
High Voltage Transmitter Connected Between Pipeline & Ground
Multi-Turn Pickup Coil Inside Receiver
Amplifier
Pipeline
Electric Field Created Around Pipe By Transmitter With The Receiver Held In The Upright Position As Shown Above, A Potential Is Induced In The Pick-Up Coil. This Is Amplified And Creates A Loud Tone In The Headphones.
Inset
Coil
Receiver
Plan View: For Most Accurate Location Of Pipeline Route, Hold Coil In Flat (Horizontal) Position. When Coil Is Directly Above Pipe, Equal And Opposite Voltages Will Be Induced In The Two Halves Of The Coil And A Sharp Null (Little Or No Sound) Will Be Detected With The Headphones.

Figure 10

V. Construction and Repair

Overview

Repair, construction, and safety are based upon good common sense. They are also based upon sound engineering concepts. This section is designed to increase the safety of your gas system by helping you meet the standards set by the regulations.

The manufacturer of pipe, valves, fittings, etc., must design and test these components to prescribed industry specifications, which are incorporated into 49 CFR 192. Those meeting the requirements are qualified for gas service and marked with the approved markings. (See Section IV.) In addition, the manufacturer usually develops separate procedures for joining his materials and for joining other materials to his product. (The manufacturer will supply you with these procedures manuals for your O&M Plan.)

This section will explain steps and procedures necessary to qualify a person to make a gas joint and how to find qualified persons to do the construction and repair work on your system. It also gives construction, pipe handling, and pressure testing requirements that should be followed when installing a gas system. If you use a gas contractor to work on your system, it is **your** responsibility to see that the contractor follows these requirements.

A. Pre-Planning

Before undertaking the redesign and/or repair of a piping system, the operator should make comprehensive plans. It is essential that a gas operator know the type of materials and all the parts that make up the present gas piping system. The piping system consists of pipe, valves, fittings, regulators, relief devices, and meters. By knowing the type of material in the system, an operator can select the proper repair fittings. Regulations require the inclusion of the proper leak repair procedures in the O&M Plan. In addition, in order to develop a cathodic protection program, it is necessary to know the type of piping in the system.

Records of the kind of material and its location are critical for pre-planning purposes. Operators who are uncertain of the type of material that makes up the gas piping system should make an effort to identify the material. This may be done in one of the following manners:

1. Contact previous owners of the system.
2. Contact the contractor who put in the system.
3. Check city or county permits, or carefully expose the pipe in certain locations to determine the type of pipe.

Operators unfamiliar with piping material will have to rely on a qualified person to identify the pipe.

B. Material Selection

Operators must carefully select pipe and other components that will make up their gas system. For an existing piping system, repair fittings selected must be compatible with the existing pipe. The publications listed in Section VII list manufacturers of gas pipe and related fittings. For master meter natural gas operators, the local gas utility may provide names of local suppliers of gas pipe and gas fittings. A person who specializes in working on gas systems can also provide this information. Make sure that all material selected is qualified for gas use. This can be done by checking either the markings on the material or certification from the manufacturer or supplier. Some manufacturers will include in their manuals, or on a tag placed on their product, a statement that the material meets the 49 CFR 192 requirements. Use Section IV of this guideline for material qualifications. After the material is selected, incorporate this data in your O&M Plan. See Appendix O for an illustration of some typical natural gas services, including main connections.

C. Excavation

1. Pipe Location

Before digging for gas line installation, repair, or replacement, you **must** locate the pipe network and other underground utility lines on the property. Lines may be located by one or all of the following ways:

a. Locate all underground utility lines on "as built" or corrected-for-construction drawings. Maps or drawings of the location of underground gas lines are **very** important. They can provide information to other utilities that must dig to repair or replace their utility lines.

b. Locate underground metallic utility lines with pipe locating instruments. Plastic pipe installed with an electrically conductive wire, as required in 192.321(e), can also be located by this method.

c. Locate or verify locations of other underground utility lines by communicating with other utility companies (electric, water, telephone) serving the area.

In some areas of the state, a single telephone call (i.e., one-call system) can be made to notify the appropriate utilities of your intention to dig. If you are in such an area, **be sure to call at least 48 hours in advance of digging**.

2. Safety Precautions

Service lines and mains built before the enactment of minimum depth requirements may be very shallow. Therefore, digging gas lines for repair or replacement should be carried out with hand tools until the gas lines are located. Afterwards, power tools may be used.

When working on a leaking pipe, a stand-by worker should be ready to help his partner escape from the hole in the event of an emergency and have a fire extinguisher ready for use.

D. Pipe Installation, Repair, and Replacement

Regulations allow gas service lines to be installed with as little as 12 inches of earth cover on private property and 18 inches of cover in streets and roads. Gas mains must have at least 24 inches of cover. The RRC recommends that gas lines be installed at greater depths, especially where soil erosion is prevalent. If local codes require greater depths than the federal or state code, use the applicable local code for underground pipe installation purposes.

Underground structures may prevent the installation of gas services or main lines at these minimum depths. If the lines are able to withstand the anticipated external loads, the standards will allow a smaller depth of cover. In such cases, the gas line location should be marked aboveground, and the area should be inspected **frequently** to ensure that the ground cover has not eroded.

Gas piping must be installed by qualified personnel. The local gas utility company may be able to recommend reputable qualified persons/contractors to install gas pipe. Local associations, such as the Texas Gas Association or mobile home associations, may have this information. However, contractor work must be supervised carefully. The following sections list required joining and construction practices that must be followed.

E. Metallic Pipe Installation

1. General Directions

Make certain that all the following conditions are met.

a. Each joint made is in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints. Obtain and follow manufacturer's recommendations for each specific fitting used. See Figure 11 for an example of a manufacturer's instructions for a mechanical coupling. Keep the manufacturer's procedures for your O&M Plan.

b. The pipe is handled properly without damaging the outside coating. Any gouges or scratches should be repaired with an appropriate coating.

c. Steel pipe is coated or wrapped at all welded and mechanical joints before backfilling. (See Appendix J)

d. New pipe is pressure tested for leaks before backfilling. MAINS to be operated at less than one psig should be tested to at least 10 psig. MAINS to be operated at or above one psig must be tested to at least 90 psig. SERVICES to be operated at one psig but not more than 40 psig must be given a leak test at a pressure of not less than 50 psig. Services to be operated above 40 psig are to be tested to 90 psig. Additional details on pressure testing are contained in Appendix O.

e. The pipe is supported along its length with proper backfill.

f. Backfill material does not contain stones or cinders that may damage or scratch pipe coating.

g. Steel pipes are cathodically protected.

h. Dissimilar metals must be electrically insulated. (See Appendix J for illustrations.)

2. Welding of Steel in Pipelines

The minimum requirements for welding steel are covered in 49 CFR 192, Subpart E and Appendix L of this manual.

a. Welding must be performed in accordance with established written welding procedures that have been qualified to produce sound ductile welds.

DRESSER

GAS PRODUCT INSTALLATION MANUAL

Style 90 Couplings and Fittings for Steel Pipe

1. Clean pipe surface to bare metal for a distance of four inches from the pipe ends (for 10″ long bodies—seven inches).
2. Loosen nuts about one-quarter turn and make sure gasket is loose.
3. Apply soap-water to gaskets (ethylene glycol should be added in freezing weather).
4. Stab pipe ends into coupling or fitting. Center coupling over joint.
5. Tighten each nut independently while holding coupling or fitting body from turning. See table for wrench size. In each case, a pull of about 75 pounds should be applied to the end of the wrench.

Recommended Wrench Sizes for use with Dresser Compression Couplings and Fittings

Nominal Steel Pipe Size (I.D.)	Recommended Wrench Size
¼″	10″
⅜″	10″
½″	14″
¾″	14″
1″	18″
1¼″	18″
1½″	24″
2″	24″

6. Line caps must be securely anchored to prevent blow-off under pressure.

   When pipe movement out of the coupling or fitting might occur, proper anchorage of the pipe must be provided.

Note: Use armored gaskets or bond coupling for cathodic protection and pipe locating continuity.

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DRESSER INDUSTRIES INC.
Bradford, Pennsylvania 16701

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Figure 11

b. Welding must be performed by welders who are qualified for the welding procedure to be used.

Welding steel pipe is difficult. Both the procedures and the personnel must be qualified for the type of weld performed. If welding must be done on the system, you may be referred to qualified welders by:

(1) The local gas utility.

(2) Local associations (such as mobile home associations, LP-Gas associations, municipal associations).

(3) A consultant.

F. Plastic Pipe Installation

Plastic pipe is now commonly used for distribution mains and services by the gas industry. The most common type of plastic pipe presently installed is polyethylene (PE). **Only** plastic pipe with the marking **ASTM D2513** on it is acceptable for gas piping. Only PE pipe manufactured according to ASTM D2513 may be installed in LP-gas systems.

Plastic pipe must be placed below ground level. Also, it may be used to replace a deteriorated buried metal pipe. A slightly smaller plastic pipe is inserted into the existing metal pipe. (See Appendix O.)

1. Qualification of Procedures (192.283)

An operator may install plastic pipe in the gas system. If so, written joining procedures must be included in the O&M Plan. Each joint must be made in accordance with those procedures which must have been proven by test or experience to produce strong gas tight joints. Plastic pipe joining procedures must be qualified according to the requirements contained in 192.283. (See Appendix M.) Personnel who make the joints must meet the requirements contained in 192.285.

Operators need not run the tests described in 192.283 themselves because most pipe and fitting manufacturers develop and qualify joining procedures for each specific product. The vast majority of small gas system operators will have neither the equipment nor the expertise to run these tests themselves. Don't purchase the product if you are not given **certification** from the pipe or fitting manufacturer or supplier that the joining procedures meet the requirements of 192.283.

Manufacturers of both pipe and fittings have installation manuals which describe the specific procedure required to make a strong gas tight joint. The manufacturer's procedures for each of the pipeline components that are used in the system should be incorporated into the O&M Plan. Caution: if you join (fuse) PE pipe manufactured by different manufacturers, you may have to develop your own joining procedures.

If a contractor installs plastic pipe, **the operator** is responsible to see that only PE pipe manufactured according to ASTM D2513 is installed. In addition, the operator should verify that the contractor has written joining procedures that meet the manufacturer's recommended joining procedures for the specific pipe and fittings used.

If you are interested in installing PE pipe, contact any of the companies listed in Appendix G for technical and sales information. The manufacturer can supply you with the nearest sales office or sales representative. Other PE pipe can be used for gas service if the operator can assure himself that the pipe meets ASTM D2513 specifications.

2. **Qualifying Persons to Make Joints (192.285)**

The material below is quoted from the regulations.

a. No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by —

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

b. The specimen joint must be —

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

NOTE: Figure 11A is an example of a manufacturer's procedure for installing a specific coupling. If the operator follows instructions and the joint has the same appearance as in the picture, then the operator has met this requirement.

(2) In the case of a heat fusion, solvent cement, or adhesive joint: (See Figures 12 through 16 for different types of heat fusion joints.)

(i) Tested under any one of the test methods listed under 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is —

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

c. A person must be requalified under an applicable procedure, if during any 12-month period that person —

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under 192.513.

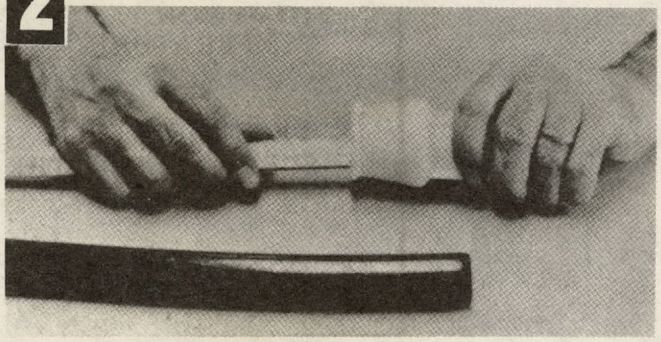
d. Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

Self-Lock Plastic Pipe Couplings utilize a very simple and basic design concept. The split grip ring expands to allow the pipe to enter the coupling. Simultaneously, the ring wedges against the tapered sidewall. The pipe is gripped by the teeth on the ring, and will not pull out of the coupling. The stronger the tensile force on the pipe, the greater the gripping action of the ring. The seal is a simple "O" ring which seals on the OD of the pipe and the ID of the coupling. All units are 100% shell tested to assure structural integrity.

1 PIPE PREPARATION

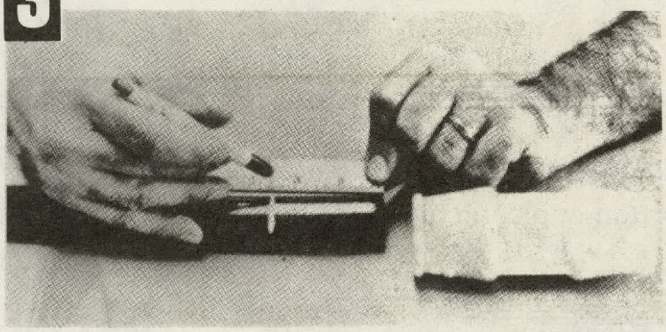
First cut polyethylene pipe as square as possible. Then, using proper KCT Chamfering Tool, lightly rotate tool several times in a clockwise direction. After several light turns, a perfect 45 degree bevel will be formed on the pipe. Inspect end of the pipe to insure there are no deep scratches. Deep gouges can ultimately result in leakage at the "O" ring seal.

2 MEASURE ENGAGEMENT LENGTH



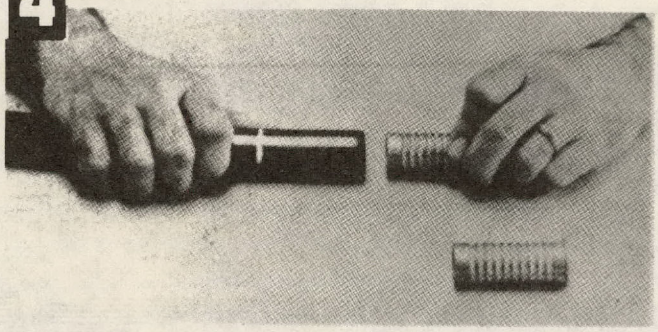
Measure engagement length or inside stab length of Self-Lock Coupling. This engagement length is given in the table, page 3, of Self-Lock Coupling Catalog SLC. Engagement length is also indicated on KCT Chamfering Tool.

3 MARK PIPE WITH ENGAGEMENT LENGTH



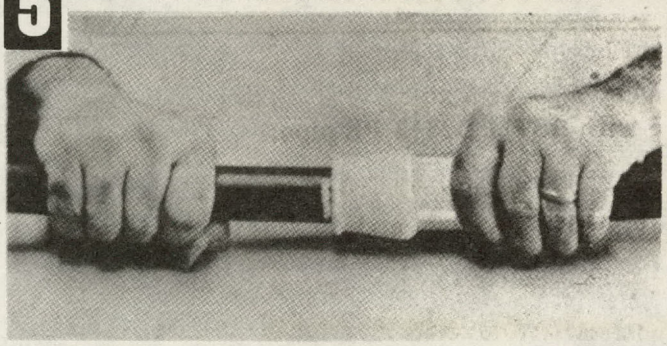
Using engagement length obtained in Step #2, mark engagement or stab length on pipe.

4 INSERT STIFFENER



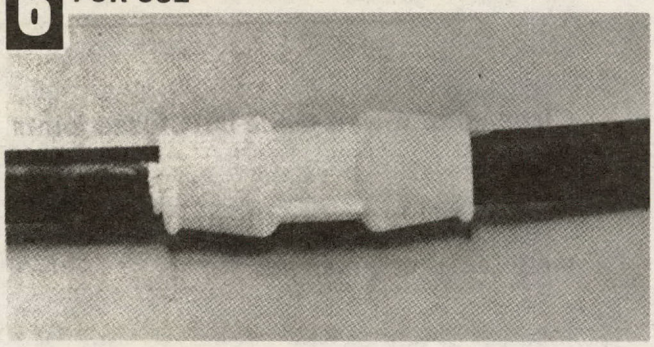
Insert stiffener into end of pipe. Stiffeners are mandatory—leakage under bending loads can occur if stiffeners are omitted.

5 INSERT PIPE INTO KEROTEST COUPLING



Lubricate the end of the pipe with a mild soap solution or water. This reduces the amount of force required to push the pipe into the coupling. Firmly grip Self-Lock Coupling. Using a rotary motion, insert plastic pipe into Self-Lock Coupling until it butts against the stop. Check for full engagement.

6 INSTALLATION BUBBLE TIGHT AND READY FOR USE



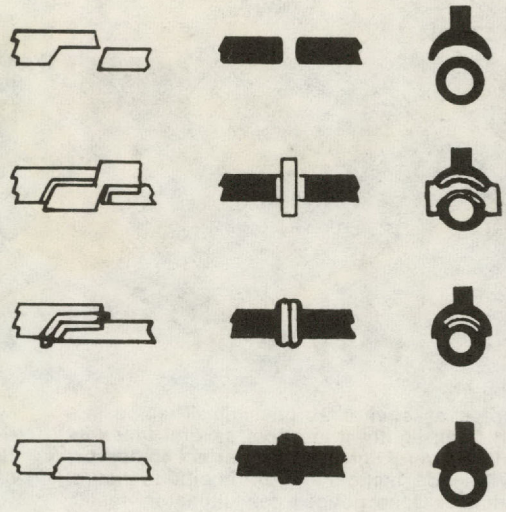
You have now completed a field joint in a matter of minutes. This joint is stronger than the polyethylene pipe and is gas tight. This coupling is ideal for field repair or new installations, eliminating the need to bring fusion equipment into the field.

Procedure for Installing a Coupling

Figure 11A

ALL THREE SYSTEMS REQUIRE

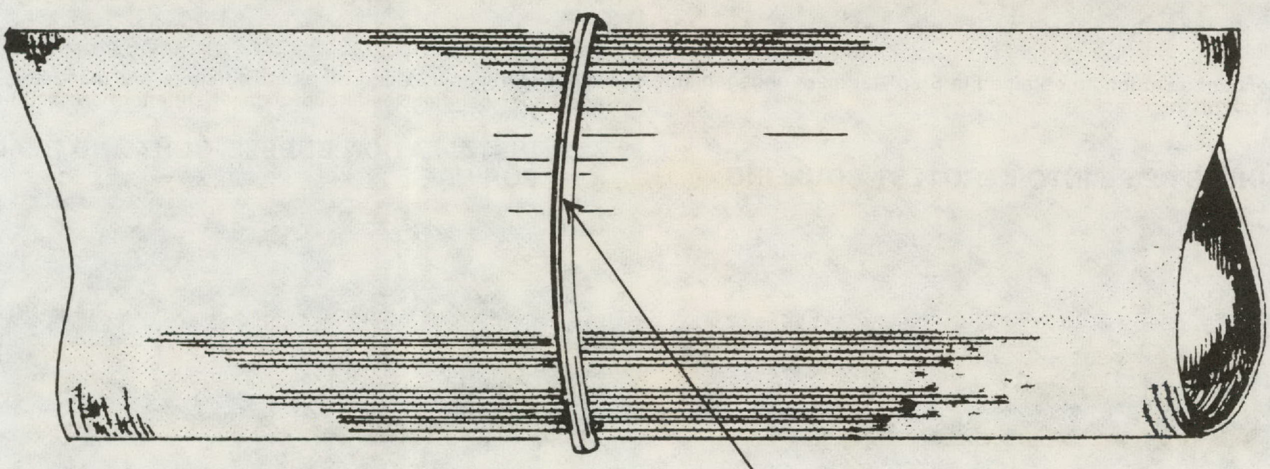
1. Mate Surfaces
2. Heat Surfaces To Fusion Temperature
3. Press Heated Surfaces Together
4. Cool Segment



These are the three types of fusion joints.

Figure 12

Bead (melted and fused portion of plastic pipe)

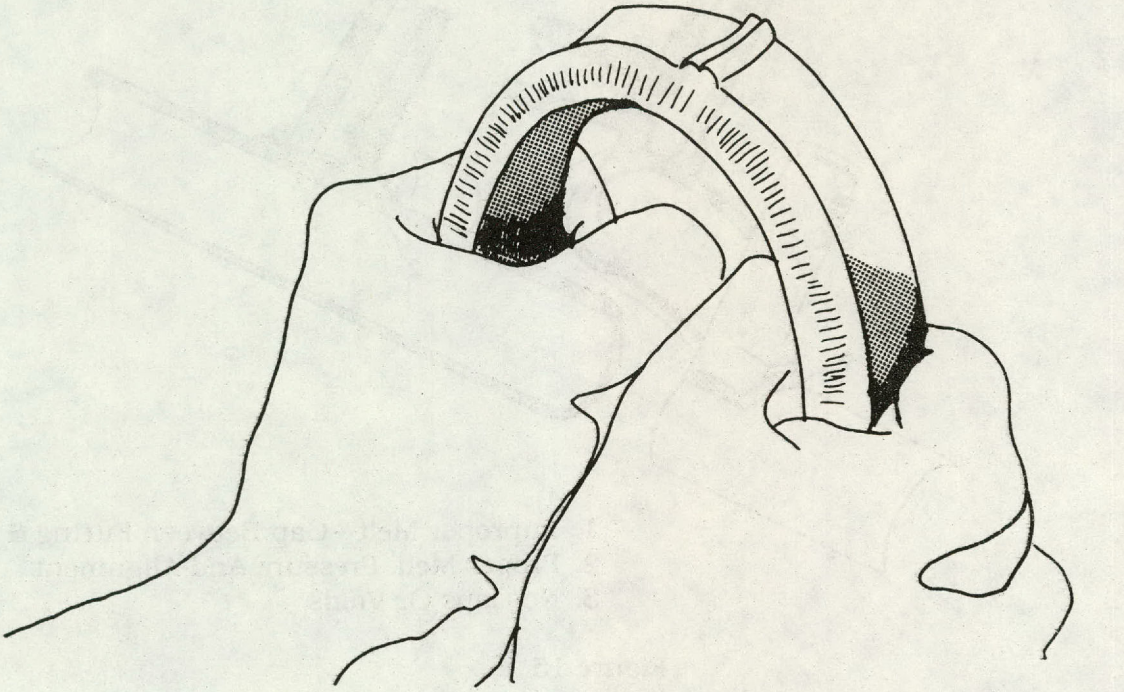


Close up of a well made butt fused joint made with ASTM D2513 PE pipe.

NOTE: This is for illustration purposes only. Use picture and instructions in pipe manufacturer's manual.

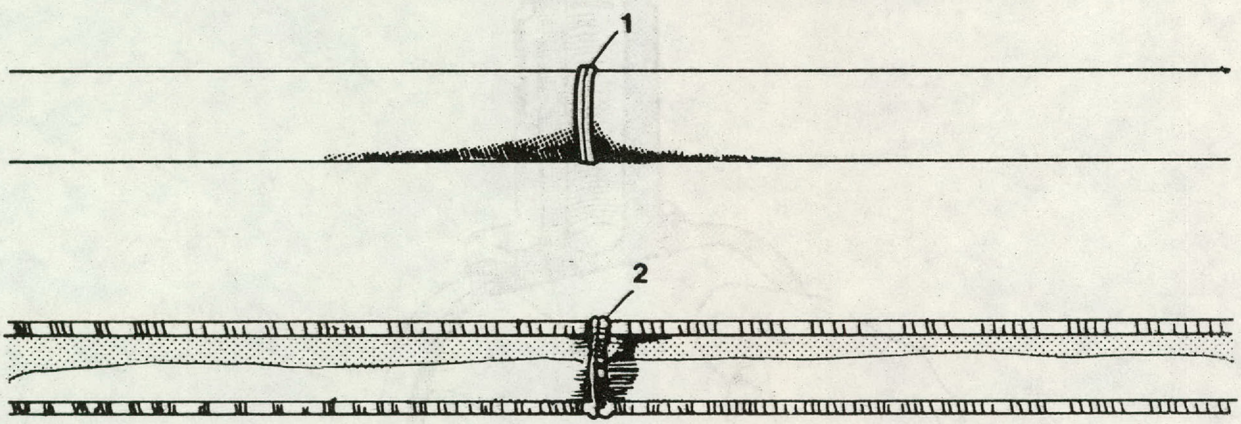
Figure 13

BUTT FUSION OF PIPE: ACCEPTABLE APPEARANCE



Proper Alignment—No Gaps Or Voids

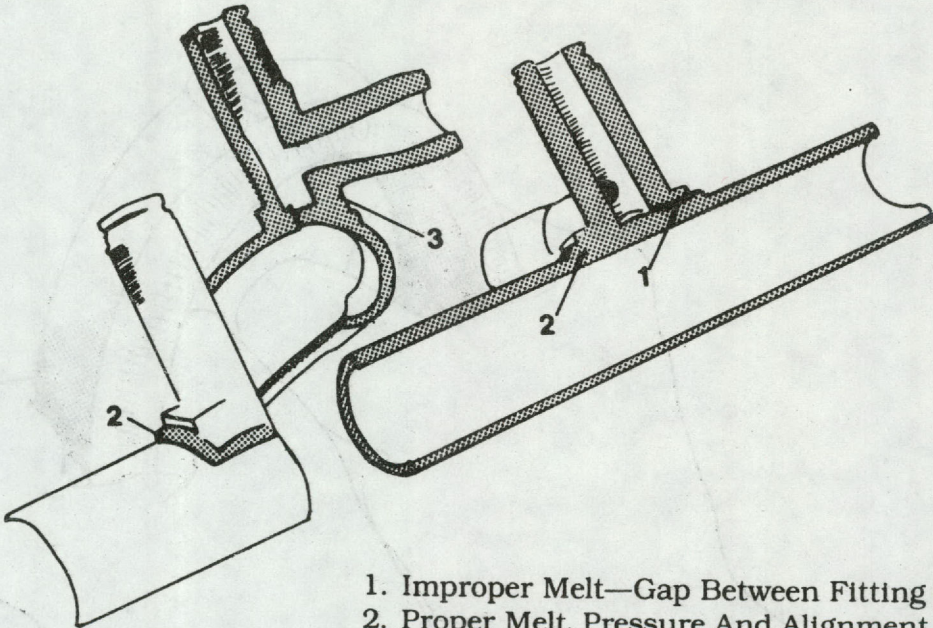
BUTT FUSION OF TUBING: ACCEPTABLE APPEARANCE



1. Proper Double Roll Back Bead
2. Proper Melt, Pressure And Alignment

Figure 14

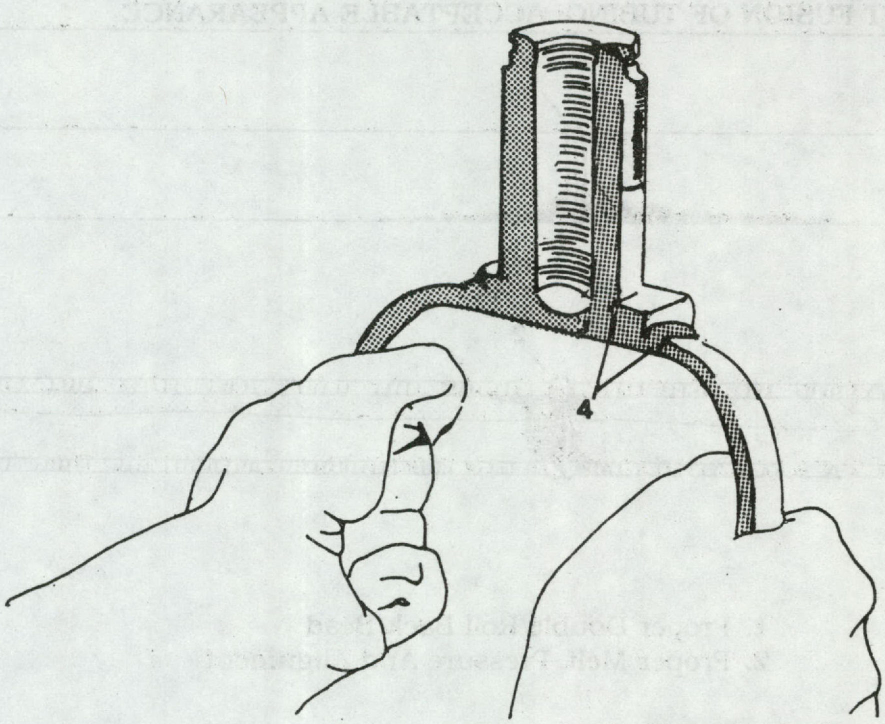
SIDEWALL FUSION: ACCEPTABLE APPEARANCE



1. Improper Melt—Gap Between Fitting & Pipe
2. Proper Melt, Pressure And Alignment
3. No Gaps Or Voids

Figure 15

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



4. No Gaps Or Voids

Figure 16

The following is a list of rules to consider when installing plastic pipe.

Rule 1: Install plastic pipe manufactured under the ASTM D2513 specification. The pipe must have ASTM D2513 marked on it.

Rule 2: Make each joint in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints.

NOTE: The manufacturer of the pipe or fitting should supply the operator with the manufacturer's procedures for his specific product. If a contractor is installing the pipe, make certain that the contractor has qualified written procedures and that the contractor follows these procedures. The contractor must use a person qualified under 192.285 to make all joints.

Rule 3: Valves for use in plastic pipe must be designed and installed in a manner that will protect the plastic material. Valves must be protected from excessive torsional (twisting) or shearing (cutting) loads when the valve is operated. And, valves must be protected from any secondary stresses that might be induced through the valve or its enclosure.

Rule 4: Prevent pullout and joint separation. When joining plastic pipe, the pipe must be installed so that expansion and contraction of the pipe will not cause the joint to pullout or separate. Operators unfamiliar with plastic pipe should have a qualified person develop these procedures.

Rule 5: When inserting plastic pipe in a metal pipe, an allowance for thermal expansion and contraction must be made. Make an allowance at lateral and end connections on inserted plastic pipes, particularly those over 50 feet in length. End connections must be designed to prevent pullout caused by thermal contraction.

NOTE: Fittings used should be able to restrain a force equal to or greater than the strength of the pipe. If not, the pipe should be restrained by anchoring, bracing, offset connecting, or strapping across the fitting. To minimize the stresses caused by thermal contraction, pipes inserted in the summer should be allowed to cool to ground temperature before tie ins are made. Inserted pipes, especially those pulled in, should be relaxed, mechanically compressed, or cooled to avoid initial tensile stress. Operators unfamiliar with proper anchoring, offset connecting, or strapping across a fitting need to have a qualified person develop the proper procedures.

Rule 6: Repair or replace imperfections or damages before placing the pipe in service.

Rule 7: In the installation of plastic pipe, all pipe must be below ground level. when the pipe is installed in a vault or other below-grade level enclosure, it must be completely encased in gas-tight metal pipe with fittings that are protected from corrosion. The plastic pipe installation must minimize shear and other stresses. Thermoplastic (PE) pipe used in direct burial must have a minimum wall thickness of 0.090 inch. Exception --pipe with an outside diameter of 0.875 inch or less may have a minimum wall thickness of 0.062 inch. Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

Rule 8: All plastic service lines must be installed below ground. A portion of the plastic service line may terminate aboveground if it is protected against deterioration and external damage by a casing. The plastic must not be used to support external loads.

Rule 9: The test pressure for installed plastic pipe must be at least 150 percent of the MAOP or 50 psig, whichever is greater. However, the test pressure may not be more than three times the design pressure of the pipe.

Rule 10: Special care must be taken to ensure that plastic pipe is continually supported along its entire length by properly tamped and compacted soil.

Rule 11: Plastic pipe laid where there has been digging and backfilling must be reinforced. To prevent any shear or other stress concentrations, use external stiffeners at connections to mains, valves, meter risers, and other places where compression fittings might be used.

Rule 12: When laying plastic pipe, there must be adequate slack (snaking) in the pipe to prevent pullout due to thermal contraction.

Rule 13: Plastic pipe must be laid and backfilled with fill material that does not contain any large or sharp rocks, broken glass, or other objects that could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.

Rule 14: Special care should be taken to prevent coal tar coatings or petroleum base tape from contacting the plastic pipe because it will cause the pipe to deteriorate.

Rule 15: **Static electricity** can ignite a flammable gas-air atmosphere. When working with plastic pipe of any kind when there is (or there may be) the possibility of a flammable gas-air atmosphere, take the following precautions:

1. Use a grounded wet tape conductor wound around, or laid in contact with, the entire section of the exposed piping.

2. If gas is already present, wet the pipe with a very diluted water detergent solution starting from the ground end. Apply tape immediately and leave in place.

3. Wet the tape occasionally with water. When temperatures are below 0° C (32° F), add glycol to the water to maintain tape flexibility. Ground the tape with a metal pin driven into the ground.

4. Do not vent gas using an ungrounded plastic pipe or tubing. Even with grounded metal piping, venting gas with high scale or dust content could generate a charge in the gas itself, and an arc could result from the dusty gas cloud back to the pipe and ignite the gas. Vent gas only at a downwind location remote from personnel or flammable material.

5. Dissipating the static charge buildup with wet rags or a bare copper wire or other similar techniques may not be as effective as the above procedure. In all cases, use appropriate safety equipment. For example, flame resistant clothing, breathing apparatus, etc.

G. Repair Methods — Plastic and Metal

Replacing gas lines and repairing leaks are highly specialized and potentially hazardous operations. Only maintenance personnel with such training, experience, and/or certification, should repair gas leaks or replace gas lines. If such personnel are not available, arrangements should be made with a qualified gas contractor, or the local gas company, to perform this work.

Leaks in service lines or mains may be repaired by cutting out a short length of pipe containing the leak. Replace it with a new segment of pipe. The pipe segment is attached to the existing line with couplings at each end. Compression or clamp couplings are commonly used for this purpose. Remember that written procedures must be followed for each joint made. The proper procedures can be obtained from the manufacturer of the coupling. If the operator intends to make the repair himself, then the written procedures **must be** incorporated into the O&M Plan.

Small leaks in service lines or mains, such as those resulting from corrosion pitting, may be repaired with a stainless steel band clamp applied directly over the leak. All bare metal pipe and fittings installed below ground must then be properly coated and cathodically protected before backfilling.

If several leaks are found and extensive corrosion has taken place, the most effective solution may be to replace the entire length of pipe that has deteriorated. For these more extensive repairs, the normal installation practices must be followed. They include priming and wrapping all bare metallic piping and fittings, proper grading of lines to the main, cathodically protecting the lines, etc.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old line and making the appropriate connections at both ends. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. Operators unfamiliar with proper anchoring and offset connections should have a gas-fitting contractor, or qualified person perform this work. Some PE pipe manufacturers include in their manuals **details** for the proper techniques when installing their product by insertion. See Appendix G for a list of the companies producing PE pipe manufactured according to ASTM D2513.

One source of failure in plastic pipe is mechanical breaks associated with compression fittings or attachment of plastic pipe to metal pipe. Such failures are caused by a combination of factors. The primary source of the problem is inadequate support of the plastic pipe. Sections 192.319, 192.321, and 192.361 prescribe firm packing of soil under the pipe to produce proper support. In practice, however, it is laborious, time consuming, and difficult to achieve adequate compaction under such joints. A contributing factor to breaks caused by excessive stress in the pipe resulting from soil settlement is the fact that in all compression fittings, an insert sleeve must be used in the plastic pipe to provide proper resistance to the clamping pressure of the compression fitting. This internal tubular sleeve must extend beyond the end of the compression fitting. (See Appendix O.) If the pipe is not properly supported at that point, the end of the insert sleeve will act as a shear. As the soil settles, the stress binds and may cut through the pipe.

This source of failure in plastic pipe can be reduced or eliminated. Use a properly designed outer sleeve to prevent stress concentrations at the point where the plastic pipe leaves the compression fitting, main, or other related connection. To the maximum practical extent, compact the soil beneath the joint. (See Appendix O.)

Again, most fitting manufacturers have detailed installation instructions. Operators should obtain these instructions from the manufacturer or his representative. Incorporate the instructions into the O&M Plan.

The most prevalent cause of breaks or leaks in plastic pipe is third-party damage. This is usually caused by a contractor breaking or cutting the pipe while digging. Plastic pipe is more vulnerable to such breaks than steel pipe. The lower strength of plastic pipe, however, is not necessarily a disadvantage. For example, if digging equipment hooks and pulls a steel pipe, it may not break. However, the steel pipe may be pulled loose from a connection at some distance from the digging. The resulting leak may go undetected for a period of time and may result in a serious incident. Although there is no assurance that the plastic pipe will not also pull out, it is more likely to break at the point of digging. Then, the break can be easily detected and repaired.

After a leak has been repaired with a coupling or a clamp, a soap test must be conducted. Replaced mains and services must be pressure tested for leaks.

Again, all sources of ignition should be kept away from the leak repair area. NEVER USE MATCHES to detect a gas leak or to test the adequacy of a repair job.

VI. Proper Locations and Design of Customer Meters and Regulators

Overview

Before you locate customer meters and regulators, first consider three points —accessibility, protecting meter sets from damage, and protecting people from gas released at meter set. This section gives the regulations covering location of meters and regulators. Illustrations show ways to achieve safe locations. Guidelines are given for and comply with 49 CFR 192.

A. Location of Customer Meters and Regulators (192.353)

1. Install meters and service regulators in a readily accessible location. Protect the meters and regulators from corrosion and other damage. Install meters outside wherever possible.
2. If you install a service regulator within a building, put it as close as practical to the point where the service line enters the building. You must vent the regulator to the outside.
3. If you install a meter within a building, you must locate it in a ventilated place. Also, it must be more than three feet from any source of ignition or any source of heat that might damage the meter.
4. It is best to locate the upstream regulator in a series outside the building. However, you may locate regulators in a separate metering or regulating building.

B. Protecting Customer Meters and Regulators From Damage (192.355)

You must protect customer meters and regulators from damage.

1. If any of your customers' equipment might create either a vacuum or a back pressure, then you must install a device to protect the gas system.
2. The outside terminal of each service regulator vent and relief vent **must be:**
   a. Rain and insect resistant;
   b. Located where gas from the vent can escape freely into the atmosphere. That is, vent it three feet or more away from any opening into the building; and
   c. Protected from water damage in areas where flooding may occur. Do not locate it where it will be underwater in a flood.
3. Meters and regulators must be installed so as to minimize stresses upon connecting piping.
4. Each regulator that is designed to release gas in its operation must be vented to the outside atmosphere three feet from openings into the building.
5. Each pit or vault that houses a customer's meter or regulator where vehicular traffic could cause damage must be able to support that traffic.

C. Operating Pressure for Customer Meter Installations (192.359)

1. A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure (67 percent x shell test pressure).

2. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psig.

D. Location of Valves on Service Lines (192.365)

1. Relation to Regulator or Meter

You must install each service-line valve upstream of the regulator. If there is no regulator, install the valve upstream of the meter. (See Figures 17 through 20.)

2. Outside Valves

Each service line must have a shut-off valve in a readily accessible location outside of the building, if feasible. (See Figure 17.)

3. Underground Valves

Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve. The box or standpipe **must not** put stress on the service line. (See Figures 17 through 20.)

NOTE: Services should not be installed under buildings or mobile homes. If a service is installed under a building, it **must** be encased in a gas-tight conduit. This conduit must vent outside to a point where gas would not be a hazard, and extend aboveground terminating in a rain and insect resistant fitting.

E. Common Problems at Service Riser and House Regulators

1. Regulator Vandalism or Damage

This can be very hazardous. If the regulator fails to function for any reason, high pressure gas may enter the appliances. Tall flames at the burner or escape of gas could cause an explosion or fire.

2. Obstructed Vents

The vent on the regulator should be free of any obstructions. A wire screen installed at the vent should prevent the accumulation of dirt, the intentional insertion of foreign objects, or the build-up of nests. If the screen is removed, a new one must be inserted in its place. A non-functioning vent could cause regulator failure and thus present a serious fire hazard within the residential unit. The vent should be pointed down and away from windows and air intakes.

3. Tenant Move-out

The valve on the riser should be equipped with a locking device to be controlled by authorized personnel only. When tenants move out, the gas is shut off and locked until new tenants move in. The locking device on the shutoff valve also allows appliances to be repaired without fear of the gas being accidentally turned on.

4. **Riser Misuse**

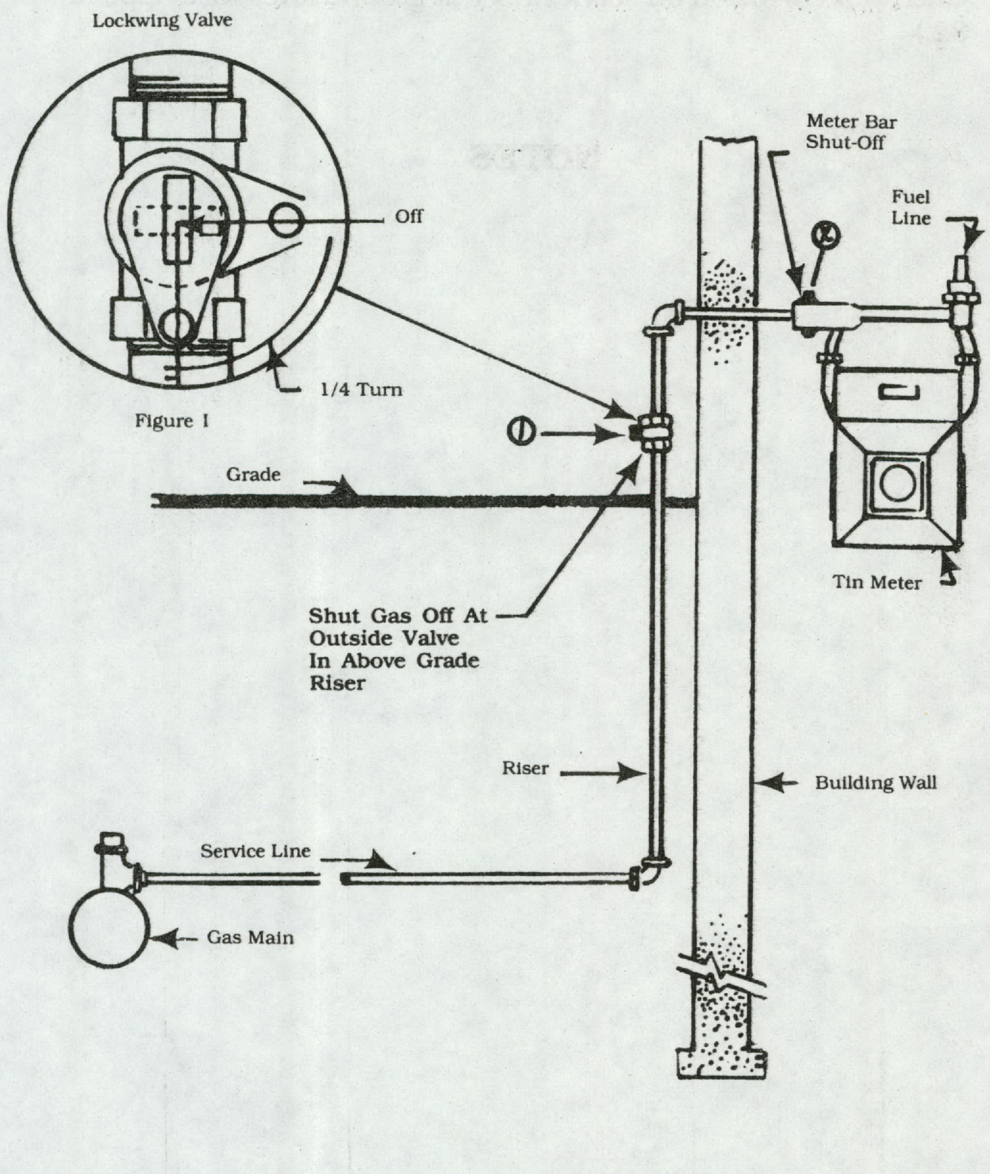
   The tenants or customers should not be allowed to use the riser and its components for other purposes, such as an anchor for laundry lines, plant supports, or bicycle racks.

5. **Corrosion**

   Check for corrosion on service riser at ground level. (See Appendix J, Figure 32.)

NOTES

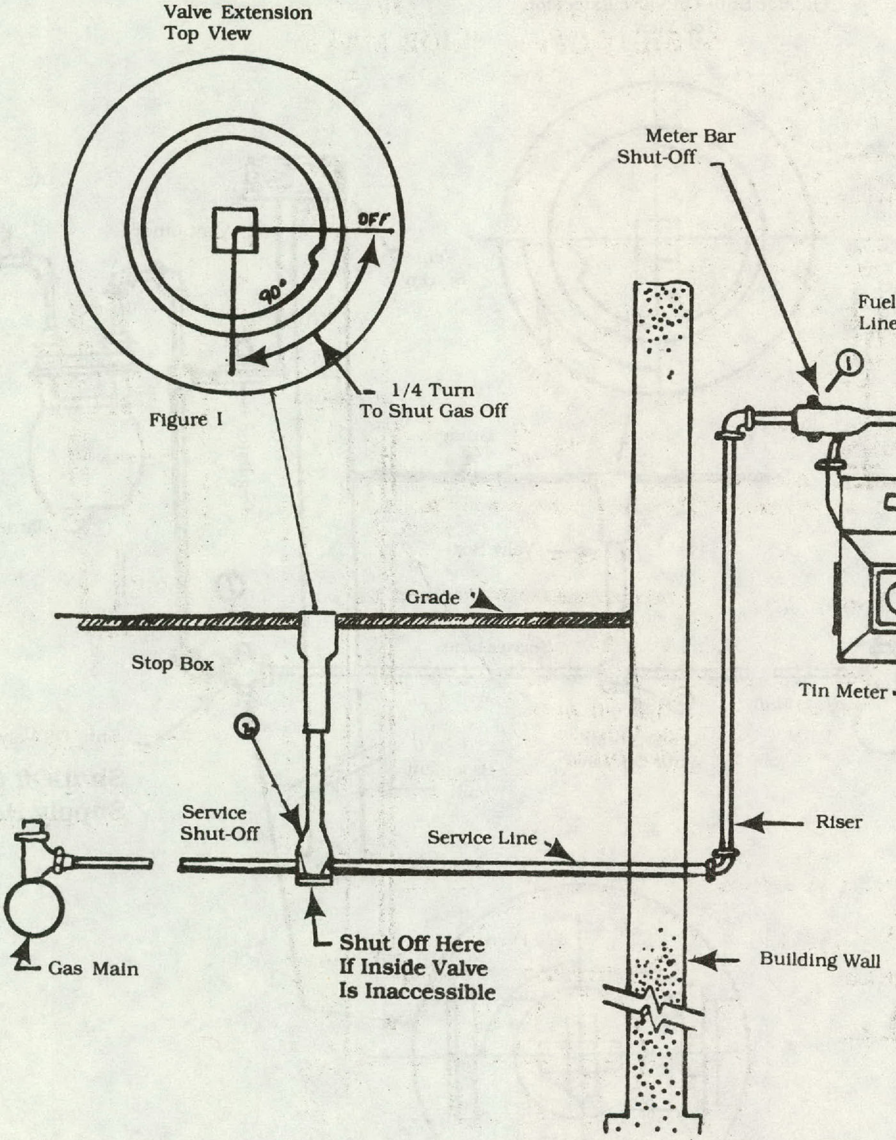
SERVICE LINES OPERATING AT LOW PRESSURE
OUTSIDE SHUT-OFF—INSIDE METER



This is a typical low pressure service (pressure in main and service are essentially the same as customer utilization pressure). Note that this service can be shut off at either (1) or (2) as shown on drawing. This service would be in compliance with 49 CFR 192.365. The valve at either point (1) or (2) must be designed so that it can be locked in a closed position.

Figure 17

SERVICE LINE OPERATING AT LOW PRESSURE BELOW GROUND OUTSIDE SERVICE VALVE

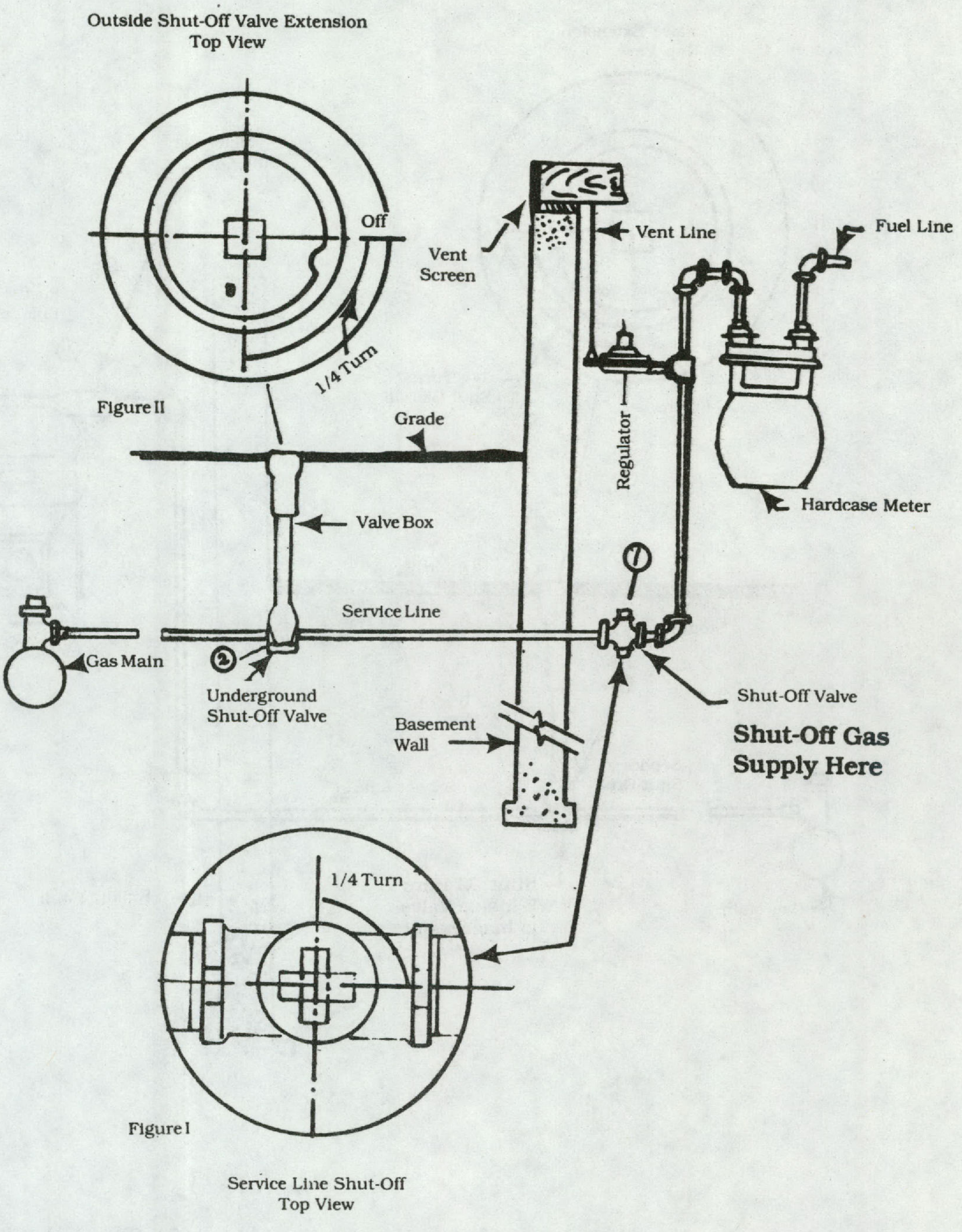


Note that this service can be shut off at either point (1) or (2). The valve at point (2) is installed in a valve box. The valve at point (1) must be designed so that it can be locked in a closed position.

Figure 18

SERVICE LINE OPERATING AT HIGH PRESSURE INSIDE METER SET

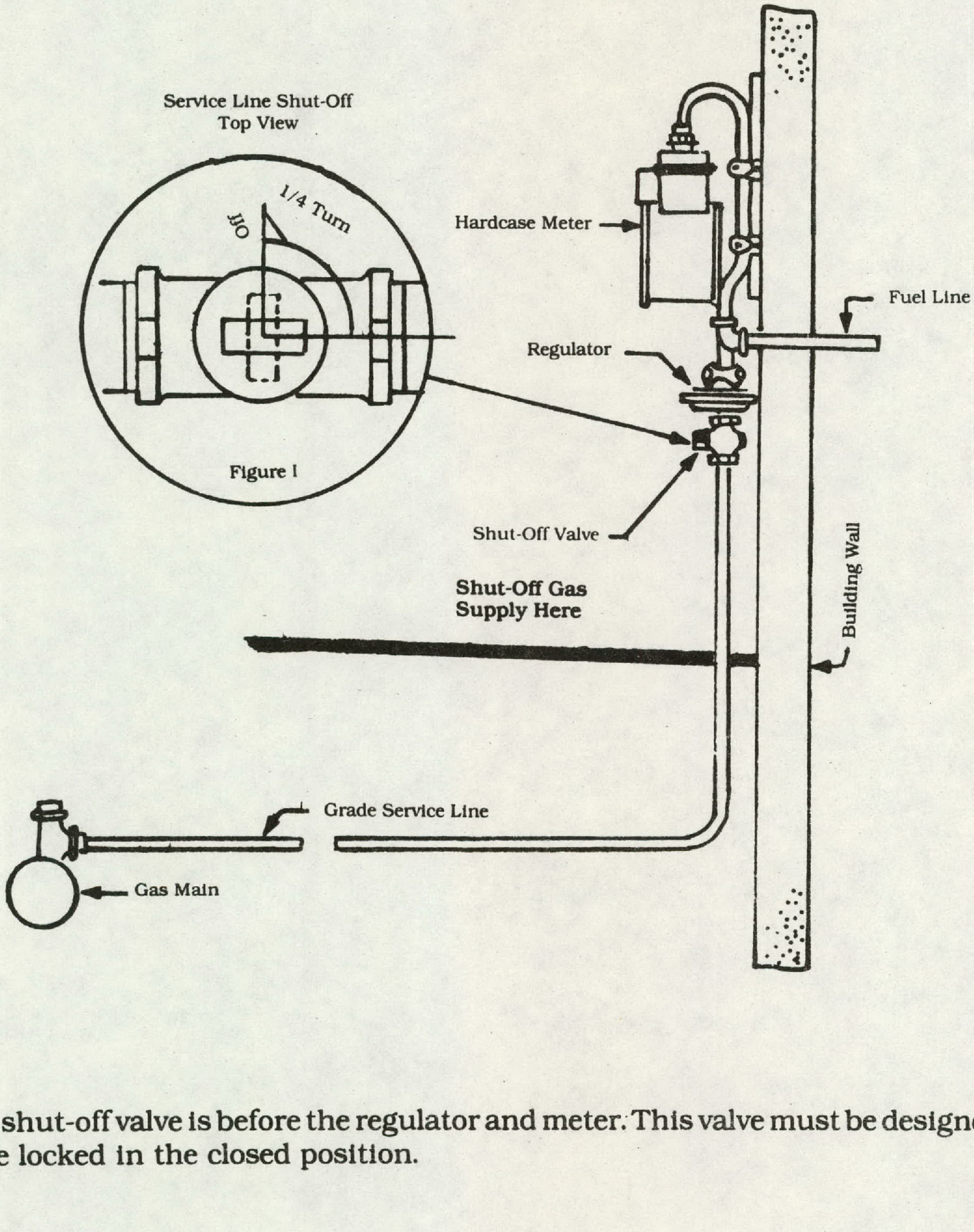
(below 60 psig)



The service can be shut off at either point (1) or (2). Note that the shut-off valve at point (1) is installed before the regulator. The valve at point (1) must be designed so that it can be closed in a locked position.

Figure 19

SERVICE LINE OPERATING AT HIGH PRESSURE
OUTSIDE METER SET



Note that the shut-off valve is before the regulator and meter. This valve must be designed so that it can be locked in the closed position.

Figure 20

NOTES

VII. Where to Find Additional Information

There are a number of gas and corrosion control magazines and journals that have useful information about operation, maintenance, and material selection for operators of small systems.

A. Some of these magazines publish "Buyers Guide Issues." These magazines include:

1. *Pipeline & Gas Journal Handbook and Buyers Guide*

   Energy Publications
   P. O. Box 1589
   Dallas, Texas 75221

   Phone: (214) 748-4403

   The Handbook and Buyers Guide, published annually on April 15, contains names and addresses of manufacturers and suppliers of gas pipe, valves, welding equipment, etc. It also lists a number of companies that specialize in cathodic protection surveys and engineering and leakage surveys. Cost for a single issue is $10.00.

2. *NACE Buyers Guide*

   NACE
   Publication Department
   P. O. Box 218340
   Houston, Texas 77218

   Phone: (713) 492-0535

   The *NACE Buyers Guide* is published annually and includes: products/services, directory of manufacturers, suppliers, and consultants serving the corrosion engineering field. A single issue costs $10.00. Specify the year's issue you wish to receive.

3. *Texas LP-Gas News*

   Texas LP-Gas Association
   P. O. Box 9925
   Austin, Texas 78766

   Phone: (512) 836-8620

   This magazine is published in odd numbered years prior to the LP-Gas trade show.

4. *LP-Gas Magazine Buyers Guide*

   LP-Gas Magazine
   Circulation Department
   One East First Street
   Duluth, Minnesota 55802

   The buyers guide is published in the regular March issue and costs $6.00. A subscription for an entire year costs $10.00, and a two-year subscription costs $16.00.

B. Other gas magazines or journals that may be of interest:

1. *Gas Industries*

   P. O. Box 1068
   Waukegan, Illinois 60085

2. *Pipeline & Gas Journal*

   Energy Publications
   P. O. Box 1589
   Dallas, Texas 75221

   Phone: (214) 748-4403

   Both of the above-listed magazines contain pertinent articles on the operation, maintenance, and construction of gas systems. Materials, such as pipe, valves, and fittings, used in gas sytems are heavily advertised in these magazines. In addition, a schedule of gas related educational courses and meetings sponsored by industry are listed.

C. For detailed information about gas piping systems:

1. The American Gas Association (AGA) is an excellent source of more general information about gas systems, materials, and gas safety publications, including Consumer Information Bill Stuffers.

   American Gas Association
   1515 Wilson Boulevard
   Arlington, Virginia 22209

   Phone (703) 841-8400

2. **TGA** (Texas Gas Association), affiliated with **AGA**, is composed of Texas gas distribution and transmission companies. The Association sponsors and conducts a graded series of training courses each year for gas system operators. These courses combine classroom instruction with actual practice.

   TGA, Inc. (Texas Gas Association)
   P. O. Box 4300
   Lago Vista, Texas 78645

   Phone: (512) 267-2933

3. The Southern Gas Association puts out several publications that could benefit operators of gas pipeline systems.

   Southern Gas Association
   4230 LBJ Freeway, Suite 414
   Dallas, Texas 75234

   Phone: (214) 387-8505

4. The National LP-Gas Association is an excellent source of information about LP-gas. It publishes the *LP-Gas Safety Handbook*, which contains information about LP-gas distribution operations, emergency procedures, safety meetings, etc. The handbook cost $15.00 in 1981.

National LP-Gas Association
1301 West 22nd Street
Oak Brook, Illinois 60521

Phone: (312) 986-4800

5. *ASME Guide for Gas Transmission and Distribution Piping Systems* contains design rules, material references, detailed engineering formulas, and other recommended practices, appropriately arranged and referenced to the minimum gas pipeline safety standards. It is an excellent source of information for a person with an engineering background.

   The American Society of Mechanical Engineers
   United Engineering Center
   345 47th Street
   New York, New York 10017

   Phone: (212) 705-7722

6. The minimum gas safety regulations incorporate two National Fire Protection Association, Inc. (NFPA) standards regarding LP-gas, NFPA 58 and NFPA 59. These standards can be obtained at this address:

   National Fire Protection Association
   Battery March Park
   Quincy, MA 02269

D. The U. S. Department of Transportation, through the Transportation Safety Institute, Oklahoma City, Oklahoma, holds pipeline safety seminars throughout the year at both the Oklahoma School and in various states.

Locations of these seminars can be obtained by calling:

Transportation Safety Institute (Pipeline Safety)
6500 South MacArthur Boulevard
Oklahoma City, Oklahoma 73125

Phone: (405) 686-2466

E. The local gas utilities are often the best source of information as to where to find local suppliers of gas pipeline components (pipe, valves, etc.). They may also be able to supply you with the names of reputable, qualified gas contractors who can work on your system.

NOTES

Appendix A

Instructions for Completing Form DOT F 7100.1-1 "Annual Report For Calendar Year 198 , Gas Distribution System"

GENERAL INSTRUCTIONS:

Each operator of a distribution system, except those exempted in §191.11(b), is required to file an annual report. Definitions are as follows:

1. "Distribution lines" means a pipeline other than a gathering or transmission line.
2. "Gathering line" means a pipeline that transports gas from a current production facility to a transmission line or main.

*3. "Transmission line" means a pipeline other than a gathering line that:
   a. Transports gas from a gathering line or storage facility to a distribution center or storage facility;
   b. Operates at a hoop stress of 20 percent or more of SMYS; or
   c. Transports gas within a storage field.

4. "Operator" means a person who engages in the transportation of gas.

The reporting requirements are contained in Part 191 of Title 49 of the Code of Federal Regulations, "Transportation of Natural and Other Gas by Pipeline: Annual Reports and Incident Reports." Except as provided in §191.11(b), each operator of a distribution system must submit an annual report Form RSPA F 7100.1-1 for the preceding calendar year not later than March 15. Be sure to report TOTAL miles of pipeline in the system at the end of the reporting year, including additions to the system during the year.

Reports should be sent to the: Information Resources Manager (DPS-40), Office of Pipeline Safety, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a state agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act may be submitted in duplicate to the State agency if the regulations of that agency require the submission of these reports and provide for further transmittal of one copy to the Information Resources Manager (DPS-40), Office of Pipeline Safety. The Operator filing this report should ensure that the regulations of the State agency provide for further transmittal of one copy of the report to the Office of Pipeline Safety, as specified to be received by March 15 of each year.

Type or print the operator name and address data in the appropriate location.

The annual reporting period is on a calendar basis, beginning January 1 and ending on December 31 of each year.

It is preferred that each independent subsidiary or affiliate operation be reported separately. Satellite divisions that have independent operations and distribution systems should continue to be reported as separate distribution systems even though, through mergers and

---

*If the operator determines that he has pipelines that fall under definition 3, he should refer to the instructions for completing Form RSPA F 7100.2-1 for transmission and gathering systems.

consolidations, they no longer are separate companies and function as a unified operation under a single corporate headquarters.

If you have any questions concerning this report or these instructions, or if you need copies of RSPA F 7100.1-1 or the instructions, please write or call the Information Resources Manager (DPS-40), Office of Pipeline Safety, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590, telephone number (202) 366-4572.

SPECIFIC INSTRUCTIONS

An entry should be made in each block for which data are available. All figures are to be reported as whole numbers. DO NOT USE DECIMALS OR FRACTIONS. Decimals or fractions should be rounded to the nearest whole number—1/2 or .5 should be rounded up. Be careful to use "miles" of mains and not "feet", use "number' of services rather than miles. The "number" of services is the number of service lines and **not** the number of customers served.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted correct information with the exception of "report date," "operator's name," "address," and "preparer". Submit only amended, revised, or added information.

Avoid "Unknown" entries if possible. Estimated data are preferable to unknown data.

Part A

The address shown should be the address where information regarding this report can be obtained.

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information may be omitted. If the pipeline system being reported on is located in more than one state, indicate all states in which this system operates.

Part B

"Coated" means pipe coated with any effective hot or cold applied dielectric coating or wrapper.

"PVC" means polyvinyl chloride plastic.

"PE" means polyethylene plastic.

"ABS" means acrylonitrile-butadiene-styrene plastic.

"Cathodically protected" applies to both "bare" and "coated."

"Other Pipe" means a pipe of any material not specifically designated on the form. An explanation should be included in Part F if "Other Pipe" is marked. If an operator has, in the past, kept records which have consolidated wrought iron pipe with steel pipe, then he may continue to do so.

"Number of services" is the number of service lines and **not** the number of customers served.

Part C

This section includes all reportable incidents and nonreportable leaks (not reported in accordance with §191.5) repaired or eliminated during the one calendar year which is indicated by the operator on the "Annual Report" form.

Leaks are defined as follows:

An unintentional escape of gas from the pipeline.

A reportable incident is one which meets the specific criteria of §191.5.

Leaks/incidents are classified as follows:

"Corrosion"—escape of gas resulting from a hole in the pipeline or component caused by galvanic, bacterial, chemical, stray current, or other corrosive action.

"Third Party"—outside force damage directly attributed to the striking of gas pipeline facilities by earth moving equipment, other equipment, tools, vehicles, vandalism, etc. Damage is by personnel other than the operator or the contractor working for the operator.

"Outside Force"—damage resulting from earth movement, including earthquakes, washouts, land slides, frost, etc. Also included is damage by lightning, ice, snow, etc., and damage done by operator's personnel or operator's contractor.

A "Construction Defect" is one resulting from failure of original sound material that is due to external force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent failure. Also included are faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

A "Material Defect" is one resulting from a defect within the material of the pipe or component or the longitudinal weld/seam that is due to faulty manufacturing procedures.

"Other" would be the result of any other cause, such as equipment operating malfunction, failure of mechanical joints, or connections not attributable to any of the above.

Indicate all leaks eliminated during the reporting year, including those reported on Form RSPA 7100.1, "Incident Report, Distribution Systems." Do not include test failures.

Include all leaks eliminted by repair or by replacement of the pipe or other component.

Part D

Federal lands: For the purposes of completing Form RSPA F 7100.1-1, "Federal lands" means all lands owned by the United States, except lands in the National Park System, lands held in trust for an Indian or Indian tribe, and lands on the Outer Continental Shelf. Indicate only those leaks repaired, eliminated, or scheduled for repair during the reporting year, including those incidents reported on Form RSPA F 7100.1.

Part E

Unaccounted for gas is gas lost, that is, gas that the operator can not account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to allow reasonable calculation or estimate; or other similar factors.

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 19____
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☐
SUPPLEMENTAL REPORT ☐

PART A – OPERATOR INFORMATION

DOT USE ONLY

1 NAME OF COMPANY OR ESTABLISHMENT

____

2 LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED

____
Number and Street

____
City and County

____
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (WHEN KNOWN)

/ / / / / /

4. HEADQUARTERS NAME & ADDRESS IF DIFFERENT

____

____

____

5. STATES IN WHICH SYSTEM OPERATES ________________

PART B – SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAINS										
NO. OF SERVICES										

2. MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL						
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON						
PLASTIC 1. PVC						
2. PE						
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS						

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR

AVERAGE SERVICE LENGTH__________ FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL						
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON						
PLASTIC 1. PVC						
2. PE						
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS						

Form RSPA F 7100 1-1 (11-85)
(Supersedes DOT F 7100 1-1

Reproduction of this form is permitted.

Figure 21

PART C – TOTAL LEAKS

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION		
THIRD PARTY		
OUTSIDE FORCE		
CONSTRUCTION DEFECT		
MATERIAL DEFECT		
OTHER		

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR ______

PART D – TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

______

PART E – PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for year ending 6/30 ____ %

PART F – ADDITIONAL INFORMATION

PART G – PREPARER AND AUTHORIZED SIGNATURE

______ / ______
Prepared by (type/print) telephone

______ / ______ ______
Name and Title of Person Signing telephone Authorized Signature

U.S. Department of Transportation

Research and Special Programs Administration

400 Seventh St. SW
Washington, DC 20590

Official Business
Penalty for Private Use $300

Postage and Fees Paid
Research and Special Programs Administration
DOT 513

U.S. MAIL

Information Resources Manager
Office of Pipeline Safety, DPS-3.3
Research and Special Programs Administration
400 7th Street, S.W.
Washington, D.C. 20590

Figure 22

State the amount of unaccounted for gas as a percent of total input for the 12 months ending June 30 of the reporting year. [(Purchased gas produced gas) minus (customer use company gas appropriate adjustments)] divided by (purchased gas produced gas) equals percent unaccounted for. Do not report "gained" gas. If a net gain of gas is indicated by the calculations, report "0%" here. (Decimal or fractional percentages may be entered.)

Part F

Include any additional information which will assist in clarifying or classifying data included in this report.

Part G

"Preparer' is the name of the person most knowledgeable about the information submitted in the report or the person to be contacted for additional information.

"Authorized Signature" may be the "preparer" or an officer or other person whom the operator has designated to review and sign reports of this nature.

NOTES

APPENDIX B

Railroad Commission of Texas
Gas Utilities Division
Pipeline Safety Section

This section consists of eight regional offices and headquarters.

Region 1 — Lubbock **Tel: (806) 744-7764**	405 50th Street Lubbock, Texas 79404
Region 2 — Midland **Tel: (915) 684-5581**	P. O. Box 2110 2509 N. Big Spring Midland, Texas 79701
Region 3 — Kilgore **Tel: (214) 984-8581**	619 Henderson Boulevard Kilgore, Texas 75662
Region 4 — Austin **Tel: (512) 463-7058**	Wm. B. Travis Bldg. 1701 N. Congress Ave. P. O. Drawer 12967 Austin, Texas 78711-2967
Region 5 — Houston **Tel: (713) 460-0635**	13201 N.W. Fwy, #701 Houston, Texas 77040-6008
Region 6 — Dallas **Tel: (214) 357-4076**	6200 Maple Avenue, Suite 102 Dallas, Texas 75235
Region 7 — Corpus Christi **Tel: (512) 242-3117**	10329 IH-37 Corpus Christi, Texas 78410
Region 8 — Abilene **Tel: (915) 672-1371**	241 Pine Street One Energy Square, Suite 17L-B Abilene, Texas 79601
Headquarters — Austin **Tel: (512) 475-0461**	Wm. B. Travis Bldg. 1701 N. Congress Ave. P. O. Drawer 12967 Austin, Texas 78711-2967

Department of Transportation
Materials Transportation Bureau
Office of Operations and Enforcement
(Pipeline Safety)

Southwest Region
6622 Hornwood Dr.
Houston, Texas 77004
Phone: (713) 750-1746

APPENDIX C

Suggested Program for Uprating of a Low Pressure Distribution System to a Higher Pressure Distribution System

A. General Requirements

Procedures for uprating a distribution system to a higher pressure must be developed and must include the following requirements:

1. **Written Plan**

   A written plan for uprating a distribution system from a lower pressure to a higher pressure must be developed and must specify the procedures to be followed before and during the uprating to ensure the safe operation of the system at the increased pressure.

2. **Pressure Increases**

   Pressure increases must be made gradually, in increments, and at a rate that can be controlled; the pressure must be held constant at the end of each increase while the affected section of the distribution system is checked for leaks.

c. **Leaks**

   Each hazardous or potentially hazardous leak detected must be repaired immediately. Other leaks should be repaired but may be monitored during the pressure increase so that they do not become potentially hazardous.

d. **Records**

   Records must be maintained for the life of the system and must include, if available, the design specifications and the operating and maintenance history of the affected section of the system. In addition, the records should include the type of work performed, investigations and tests performed, number of incremental increases and corresponding pressures, leaks detected and repaired, replacements or alterations performed, date and name of person responsible, and the increased pressure.

B. Procedures

Procedures developed for uprating a distribution system from a low pressure to a higher pressure should recognize the type of pipe (steel, cast iron, ductile iron, or plastic) in the system and the operating pressure limitations imposed on the particular type of pipe. The procedures must also provide for a detailed review of the design, operating and maintenance history of the affected section of the system so its condition can be evaluated before the operating pressure is increased.

In addition, the procedures must provide for making a leakage survey (if time elapsed since the last survey exceeds one year), repairing any hazardous leaks found, and monitoring all other leaks during the pressure increase. Make repairs, replacements, or alterations necessary for safe operation at the increased pressure, including the reinforcement of anchoring of offsets, bends, and deadends in piping joined by compression couplings or bell and spigot joints, if the pipe is exposed at these points during excavation.

Furthermore, the procedures must include provisions for isolating the section of the distribution system in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure. Monitor the adjacent low pressure segment of pipeline to ensure that it is not being affected by the pressure increase. The procedures must also specify that if the new increased pressure in the affected segment of pipeline is to be higher than the normal utilization pressure, a service regulator will be installed and tested for each customer.

Once the above-mentioned procedures are followed, the increase to a higher pressure must be made in increments that are equal to 10 psig or 25 percent of the total pressure increase, whichever produces the fewer number of increments. However, when the new increased pressure in the affected segment of pipeline is to be higher than the normal utilization pressure and a service regulator has to be installed and tested for each customer, there must be at least two approximately equal incremental pressure increases. The procedures must also specify that if the records for cast iron or ductile iron distribution systems are not thorough enough to determine the initial design and laying conditions, the operator shall assume that unless the manufacturing process for cast iron pipe is known, the pipe is pit cast with a bursting tensile strength of 11,000 psi and a modulus of rupture of 31,000 psi. The operator shall also assume that when applying the design formulas of ANSI A21.1, the cast iron pipe was supported on blocks with tamped backfill, and that when applying the design formulas of ANSI A21.50, the ductile iron pipe was laid without blocks with tamped backfill.

In addition, the procedures must specify that unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and use the greatest cover measured. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons taken from at least three separate pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance set forth in the table under 49 CFR 192.557(d)(3).

NOTES

Appendix D

Methods of Leak Detection

A. Warning Sign of a Leak

A leak may be indicated by one or more of the following:

1. **Odor**

   Gas is required to be odorized so that the average person can perceive it at a concentration well below the explosive range -- generally between one-half to one percent by volume. Gas odor is the most common and effective indication of a leak. A report of a gas odor should be investigated immediately. However, the odor of gas may be filtered out as the odorized gas passes through certain types of soil, or modified by passing through soil and into a sewage system containing vapors or fumes from other combustibles as well as the sewage odor itself. Therefore, odor is not always totally reliable as an indicator of the presence or absence of gas leaks.

   In making your maintenance rounds, always be alert for the smell of gas.

2. **Vegetation**

   Vegetation in an area of gas leakage may improve or deteriorate depending on the soil, the type of vegetation, the environment, the time of year, and the volume and duration of the leak. Changes in vegetation take time and therefore can be observed to discover slow sub-soil leaks. Vegetation surveys are considered to be an aid to surveying for gas leaks but should be supplemented with leak detecting instruments. (See Figures 23 and 24.)

   NOTE: This method is neither recommended nor approved to be used as the sole leak survey method.

3. **Insects** (flies, roaches, spiders)

   Insects migrate to points or areas of gas leakage because of microbial breakdown of some components of gas. Some insects seem to like the smell of the gas odorant. Keep your eyes open for heavy insect activity, particularly near the riser, the gas meter, and the regulator.

4. **Fungus-Like Growth**

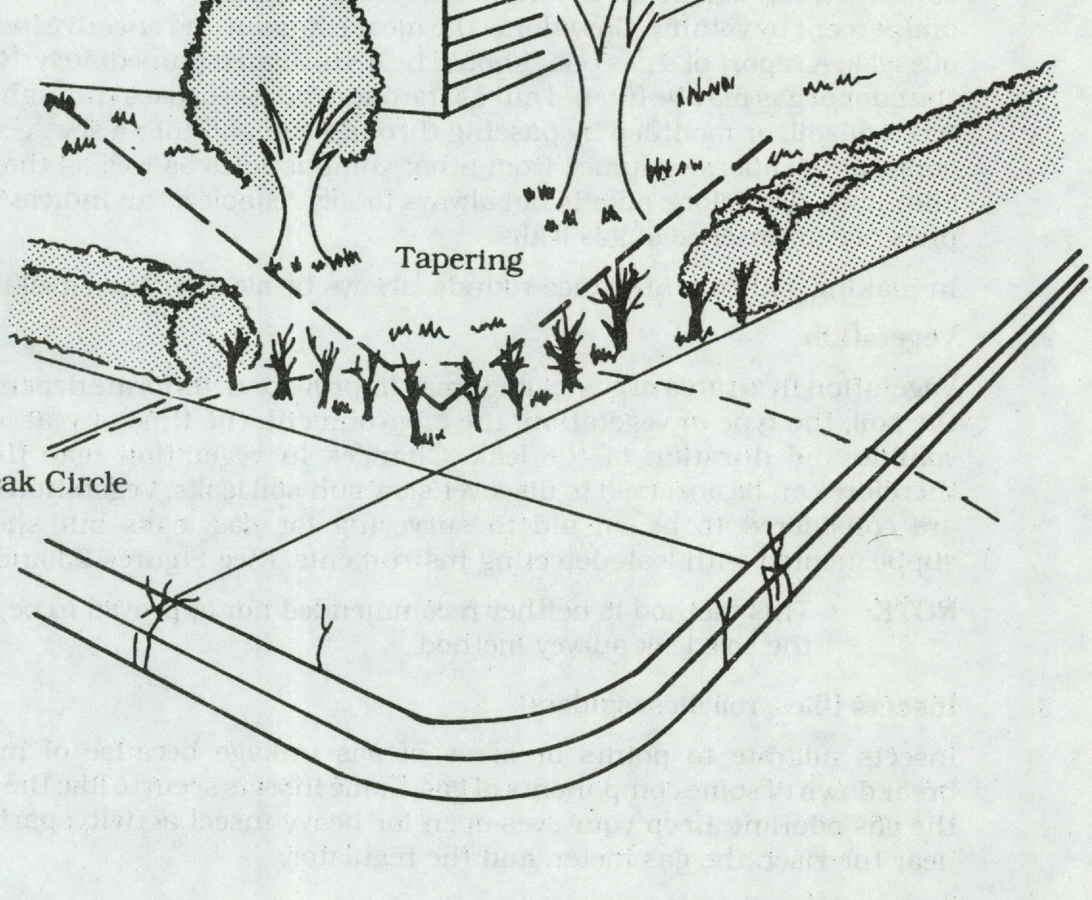
   Such growth in valve boxes, manholes, etc., indicates gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

5. **Sound**

   Listen for leaks. A hissing sound at a bad connection, a fractured pipe, or a corrosion pit hole are usual indications of a gas leak.

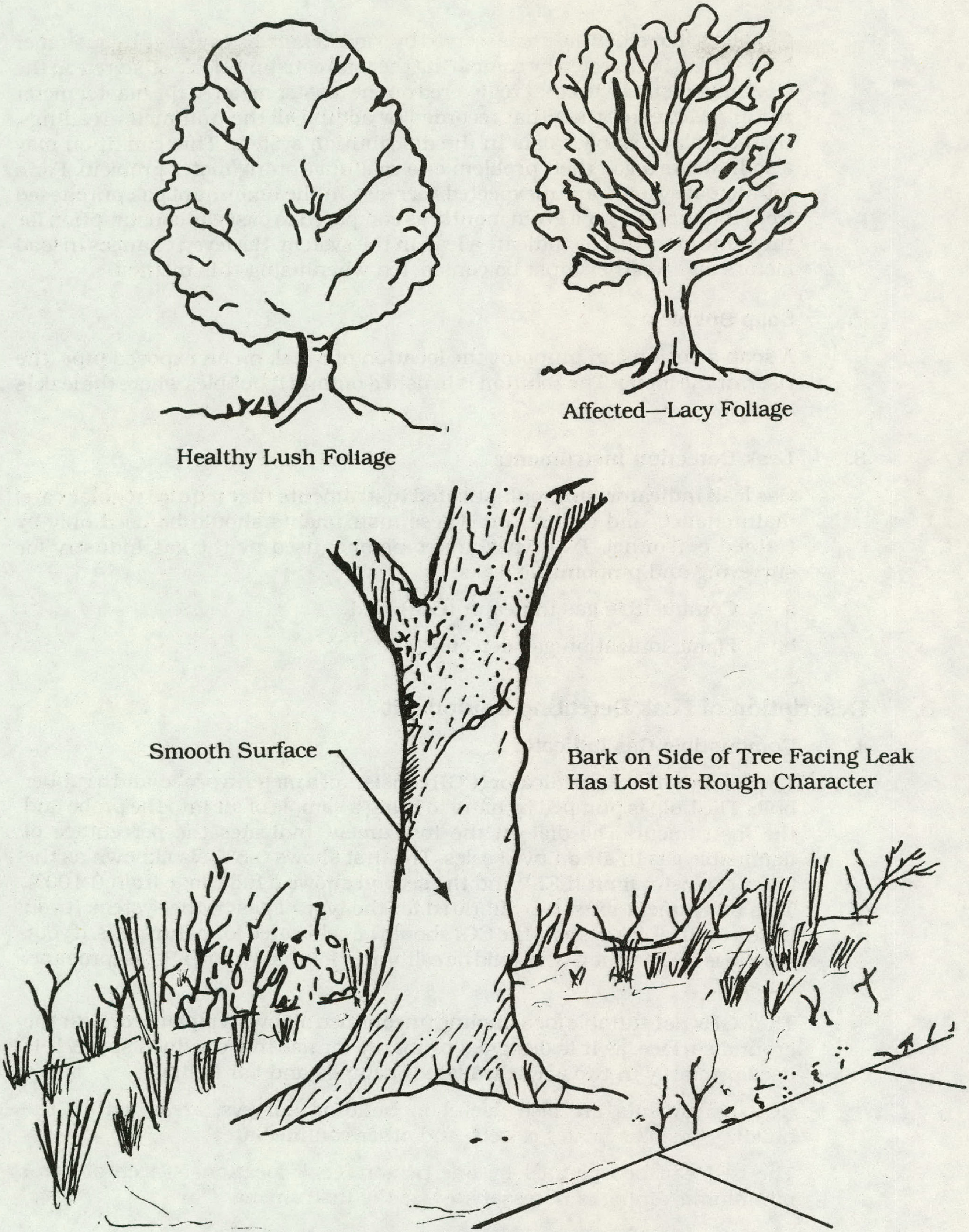
6. **Unaccounted for Gas**

   A possible leak is indicated when an offpeak reading of a master meter with a known average seasonal utilization rate shows an unaccountable high usage rate. Periodic offpeak checks (the summer months from midnight to three or four o'clock in the morning are preferable) can be averaged to provide data for comparison in future checks.



EFFECT OF GAS LEAKAGE IN A GAS MAIN ON A HEDGE

Figure 23



USE OF TREES AS GAS LEAK INDICATORS

Figure 24

Gas leaks in residential areas (served by a master meter as well as by customer meters) can be detected by comparing the total consumption registered on the customer meters with that registered on the master meter. If the master meter reading is greater than that recorded by adding all the unit meter readings, then a leak probably exists in the distribution system. This condition may also indicate a gas theft problem or a malfunctioning meter problem. For a municipal system, an unexpected increase in the amount of gas purchased from the supplier for a given month, as compared to past gas consumption for the same month, may indicate a leak in the system. However, changes in load factors and weather must be considered when using this method.

7. **Soap Bubbles**

A soap solution can pinpoint the location of a leak on an exposed pipe, the riser, or the meter. The solution is brushed on, and it bubbles where the leak is located.

8. **Leak Detection Instruments**

Gas leak indicators are sophisticated instruments that require regular care, maintenance, and calibration. These instruments should be used only by trained personnel. Two types are commonly used by the gas industry for surveying and pinpointing leaks:

a. Combustible gas indicator (CGI); and

b. Flame ionization gas detector (FI).

B. Description of Leak Detecting Equipment

1. Combustible Gas Indicator

The combustible gas indicator (CGI) consists of a meter, a probe, and a rubber bulb. The bulb is pumped by hand to bring a sample of air into the probe and the instrument. The dial on the instrument indicates the percentage of flammable gas in air on two scales. The first shows 0-5%, also known as the lower explosive limit (LEL), and the second shows a full range from 0-100%. This instrument must be calibrated for the type of gas in the system. If you have a natural gas system, the CGI should be calibrated for natural gas. If your system is LP-gas, the CGI should be calibrated for that type of LP-gas (propane, butane).

The CGI is not suitable for sampling unconfined air over a pipeline or near the ground surface, as it is designed primarily for use in a confined space. It is used primarily in two ways: available openings and bar holing.

CGI instruments are also useful in building surveys, areas within the building, such as heater closets, and other confined areas.

The CGI can be operated by one person. Leak location is accurate and minimum training is necessary to use the instrument.

The following table lists the upper and lower explosive limits for LP gases.

Table 1

Limits of flammability in air, percent of LP-gas vapor-in-air gas mixture. At this percentage the mixture will burn, or may explode.

	Commercial Propane NLPGA Average	Commercial Butane NLPGA Average
Lower Limit	2.15 percent	1.55 percent
Upper Limit	9.60 percent	8.60 percent

2. **Flame Ionization Unit** (does not apply to LP-gas operators)

This unit consists of a hydrogen-air source, a flame jet, two electrodes, and an electrometer. During operation, a hydrogen flame is ignited at the flame jet and the electrodes collect a small current which is generated when combustible materials in the sample gas enter the hydrogen air flame. The electrometer amplifies this current for meter readouts, alarm signals, or both.

FI units can be hand carried or mounted on a vehicle. These instruments are extremely sensitive, having sensitivity range selections from 0 to 5,000 ppm or 10,000 ppm (methane in air). The cost of an FI unit is approximately $3,500.

The units are popular with large and medium sized natural gas operators not only because of their sensitivity, but also because a leakage survey can be conducted over a system in a much shorter time than the CGI bar holing method. However, an FI unit can not pinpoint underground leak locations. This means once an FI unit picks up a gas indication, a CGI unit may still be needed to pinpoint the leak.

Operators of FI units require more training than operators of CGIs, and FI units are more difficult to maintain. If a small operator must make a choice between an FI unit, or a CGI, purchasing a CGI would be more practical.

Operators of small systems can rely on their consultant, or hire a leak survey contractor to run FI surveys directly over the line needing to be surveyed, rather than purchasing an FI.

C. Recommended Method for Surface Gas Detection Survey with FI Unit

A continuous sampling of the atmosphere for buried mains and services should be made at ground level, or at no more than two inches above the ground surface. In areas where the gas piping is under pavement, samplings should also be at curb line(s), available ground surface openings (such as manholes, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes, or cracks in the pavement or sidewalk), or other interfaces where gas is likely to vent. For exposed piping, sampling should be adjacent to the piping.

D. Recommended Method for Subsurface Gas Detection Survey with CGI

The subsurface gas survey using the CGI with a bar hole survey is a method recommended by the Railroad Commission of Texas for a leak detection survey on an LP-gas system.

Any CGI used in a leak survey should be capable of detecting ten percent of the LEL at the sample point.

Perform tests with a CGI in a series of bar holes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures) adjacent to the gas facility. The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or pipeline will depend on soil and surface conditions but should never be more than 20 feet apart. Where the facility passes under paving for a distance of 20 feet or less, tests should be made at the entrance and exit points of the paved area. Where the paved area over the facility is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive paving, permanent test points should be considered, particularly in low places. The sampling pattern should include tests at potential leak locations, such as threaded or mechanical joints, and at building walls at the service riser or service line entrance. All available openings adjacent to the facility should be tested.

When testing available openings for LP-gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas, including floor drains, should be tested thoroughly because gases can lie temporarily in pockets containing explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. When conducting the survey, all bar holes should penetrate to the pipe depth where necessary in order to obtain consistent and worthwhile readings. The required depth of the test hole will depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. Readings should be taken at the bottom of the test holes. The probe used should be equipped with a device to prevent fluids from being drawn into the probe. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be investigated further to determine the source of the gas. Care should be taken to avoid damaging the pipe and/or coating with the probe bar.

This survey method should be utilized for buried facilities. Good judgment must be used to determine when the recommended spacing of sample points is inadequate. Additional sample points should be provided under these conditions. Available openings (such as manholes, vaults, and valve boxes) should be tested. However, they should not be relied upon as the only points used to test for gas leakage.

E. Records

Operators must record all leakage surveys and all repair data. A sample form that may be used is in Appendix E (Form 102.1). Remember that you, as an operator, may develop your own forms.

This criteria must include receiving leak reports from your customers or tenants. A sample form of the recording of these leak reports is in Appendix E, Form 109.1.

F. **ASME Guide Material for Leak Classification and Action Criteria**

ASME has developed guidelines for classifying leaks and the action required. (See following pages for guidelines.)

G. **Follow-Up Inspections**

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Grade 1 leak, a follow-up inspection should be made as soon as practical (but no more than one month after the repair) after allowing the soil atmosphere to vent and stabilize. In the case of other leak repairs, the need for a follow-up inspection should be determined **by qualified personnel**, but should be monitored.

LEAK CLASSIFICATION AND ACTION CRITERIA — GRADE 1

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires *prompt action** to protect life and property, and continuous action until the conditions are no longer hazardous. *The prompt action in some instances may require one or more of the following. a. Implementation of company emergency plan (192.615). b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments.	1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas which has migrated into or under a building, or into a tunnel. 4. Any reading at the outside wall of a building or where gas would likely migrate to an outside wall of a building. 5. Any reading of 60% LEL, or greater, in a confined space. 6. Any reading of 60% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, or felt and which is in a location that may endanger the general public or property.

LEAK CLASSIFICATION AND ACTION CRITERIA — GRADE 2

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
2	A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered: a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions (such as frost cap, moisture and natural venting.) Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working 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. 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 reinspection as necessary. Grade 2 leaks should be reevaluated at least once every 3 months until cleared. The frequency or reevaluation should be determined by the location and magnitude of the leakage condition.	A. *Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions.* Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. B. *Leaks Requiring Action Within Six Months* 1. 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. 2. 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. 3. Any reading less than 60% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. 4. Any reading of less than 60% LEL in a a confined space. 5. Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater in gas associated substructures. 7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

LEAK CLASSIFICATION AND ACTION CRITERIA — GRADE 3

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. Because petroleum gas is heavier than air and will collect in low areas instead of dissipating, few leaks can safety be classified as Grade 3.	These leaks should be rechecked within 3 mos. of date reported to substantiate the grading. Thereafter, these leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.	*Leaks Requiring Reevaluation at Periodic Intervals.* 1. Any reading of less than 80% LEL in small gas associated substructures. 2. 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.

Appendix E

Sample Forms

GENERAL MAINTENANCE SCHEDULE

1.	* Patrol Transmission Lines	192.705	Use Form 103.1
2.	Patrol River Crossings, Railroad And Highway Crossings	192.705	Use Form 103.1
3.	Gas Leak Detection Surveys	192.723	Use Form 102.1
	* Downtown Business Areas	192.723	Use Form 102.1
	Distribution Mains and Services	192.723	Use Form 102.1, 103.1
4.	Pressure Regulating Stations	192.739	Use Form 105.1
5.	* Regulator Stations, Recordings of Pressures	192.741	Maintain And Save All Recording Charts (Date Charts And File In Order By Date)
6.	Pressure Relief Valves	192.743	Use Form 105.1 (a)
7.	Valve Maintenance, Distribution Lines	192.747	Use Form 106.1, 107.1
8.	Odorization Of Gas (Sniff Test)	192.625	Use Form 108.1 and 108.2
9.	Corrosion Control (External)	192.465	Use Form 111.1
10.	Corrosion Control (Atmospheric)	192.481	Use Form 110.2
11.	Corrosion Control (Examination)	192.459	Use Form 101.1
12.	* Corrosion Control (Rectifiers)	192.465	Use Form 112.1
13.	Testing Of Pipe	192.501 TO 192.517	Use Form 113.1

* May not apply to master meter operators

GENERAL MAINTENANCE SCHEDULE

			Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1.	* Patrol Transmission Lines	192.705												
2.	Patrol River Crossings, Railroad And Highway Crossings	192.705												
3.	Gas Leak Detection Surveys	192.723												
	* Downtown Business Areas	192.723												
	Distribution Mains and Services	192.723												
4.	* Pressure Regulating Stations	192.739												
5.	* Regulator Stations, Recording Pressures	192.741												
6.	Pressure Relief Valves	192.743												
7.	Valve Maintenance, Distribution Lines	192.747												
8.	Odorization Of Gas (Sniff Test)	192.625												
9.	Corrosion Control (External)	192.465												
10.	Corrosion Control (Atmospheric)	192.481												
11.	Corrosion Control (Examination)	192.459	Examine And Record Observations Anytime Buried Piping Is Exposed											
12.	* Corrosion Control (Rectifiers)	192.465												
13.	Testing Of Pipe	192.501 TO 192.517	Test And Record New Pipe Installation Or Connections Per This Section											

NOTE: Shade In Month You Intend To Perform Work And Post In A Prominent Place As A Reminder

* May Not Apply To Master Meter Operators

Form 101.1

________________________ Gas Company

REPORT OF MAIN AND SERVICE LINE INSPECTION

This form to be completed each time a transmission line, distribution main, or service line is uncovered for inspection or other reason, such as making service connection, main extension, replacement, etc.

(If you are not POSITIVE, leave answer blank)

Date: ________________ 19 ____

1. Location: ________________________

2. Name of Inspector: ________________________

3. Designation of Line: Trans. ____________ Dist. ____________ Service ____________

4. Age: ________ Years Line Size: ____________ Inches

5. Maximum Operating Pressure: ________________________

6. Pipe Specification: ________________________

7. Cathodic Protection: Yes ______ No ______ Anodes ____________ Other ____________

8. Coating: Type ________________ Condition ________________

9. External Condition: Smooth ____________ Pitted ____________ Depth of Pits ____________

10. Internal Condition: Smooth ____________ Pitted ____________ Depth of Pits ____________

11. Other Structures in Area Endangering Pipeline: ________________________

____

____

12. Condition of Right-of-Way: ________________________

____

____

13. Corrective Measures Taken If Needed: ________________________

____

14. Number of Anodes Installed: Size ____________ Location ________________________

15. Soil: Kind: Sand ( ) Clay ( ) Loam ( ) Cinders ( ) Refuse ( )

Packing: Loose ( ) Medium ( ) Hard ( )

Moisture Content: Dry ( ) Damp ( ) Wet ( )

FORM NO. ______________

Form 102.1

Date ______________

Time of Test ______________

Leak Classification Grade I II III

LEAKAGE CONTROL REPORT

TIME **REPORTED** ______________

GRADE I LEAK ONLY

Operator ______________

City ______________

Nearest Street Address or Intersection

____

TYPE OF GAS

Natural	
Other ________	

PIPE DESIGNATION

Distribution - psig	
Transmission - psig	
Gathering - psig ____	
Other ________	

CGI TEST

Highest Reading ____	
Reading Closest To Structure ____	

LEAK INDICATION FIRST DETECTED (AT) (IN) (BY)

Atmospheric (odor)	
Bar Hole Test	
Man Hole	
Pit (Reg. or Meter)	
Valve Box	
Main Valve	
Curb Valve	
Meter Box	
Vegetation Damage	
Other________	

METHOD OF SURVEY

Flame Ionization	
Other ________	

LOCATION OF PIPE

Street	
Between St. & Sidewalk	
Under Sidewalk	
Lawn	
Easement	
R. O. W.	
Other ________	

LEAK INDICATION APPEARS TO BE AT:

Main	
Service	
Service Tap	
Main at Tie In	
Drip	
Meter	
Curb Valve	
Main Valve	
Other ________	

COVER

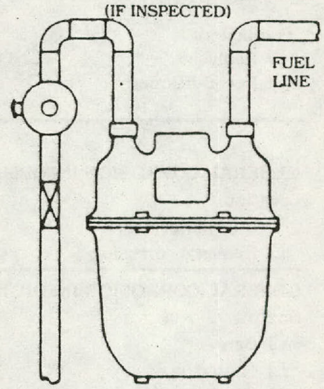
Concrete	
Asphalt	
Brick	
Gravel	
Soil	
Other ________	

N

LOCATION SKETCH
(NOTE DISTANCE TO BUILDINGS AND STRUCTURES)

METER SET

Meter No. ______________
(IF INSPECTED)



Meter Inside ☐ Outside ☐
Regulator Inside ☐ Outside ☐

MONITORING INFORMATION

DATE	STATUS	% GAS

REMARKS ______________

____

____

____

____

PERSONS PERFORMING SURVEY TESTS

____

____

OPERATOR COPY RECEIVED BY

____

Repair Date ______________

By ______________

RRC—PS—27 11/80

LEAK REPAIR DATA

Form 102.1(a)

Date ______________________ Work Order No. ______________________

Labor:—Foreman Hrs. ______________ Man Hrs. (skilled) ______________ Man Hrs. (unskilled) ______________

Material Used ____

Equipment ____________________________________ Hrs. __________

Number of Leaks Repaired (this location) ______________ Total Cost ______________

PART OF SYSTEM WHICH LEAKED OR FAILED

Part

- ☐ Pipe ☐ Drip ☐ Other *(Specify)* ______________
- ☐ Valve ☐ Regulator
- ☐ Fitting ☐ Tap Connection

Date Installed ______________

PIPE DESCRIPTION *(Where Applicable)*

____

Nominal Diameter *(inches)* Nominal Wall Thickness *(inches)*

____

Specification and grade Grade

MATERIAL WHICH LEAKED OR FAILED

Material

- ☐ Steel ☐ Copper ☐ Other (Specify) ______________
- ☐ Plastic ☐ Ductile iron
- ☐ Cast iron ☐ Wrought iron

Was the material that leaked or failed the same material as adjoining pipe or component? ☐ Yes ☐ No

(If "No," describe material in the adjoining component or parts)

Is a metallurgical analysis planned?

☐ Yes ☐ No

ENVIRONMENTAL DESCRIPTION

Predominant type or area

- ☐ Commercial ☐ Rural
- ☐ Industrial ☐ Unknown
- ☐ Residential ☐ Other *(Specify)* ______________

Predominant aboveground structure adjacent to leak

	Multi-story	Single Story
Commercial	☐	☐
Industrial	☐	☐
Residential	☐	☐
Other *(Specify)* ______________	☐	☐

Approximate distance to nearest aboveground structure *(Within 1 mile of leak)* ______________ feet

Did other underground facility(ies) contribute to occurrence of leak in any manner? ☐ Yes ☐ NO

If so, what was effect of existence of other facility(ies)?

____

ORIGIN OF LEAK OR FAILURE

- ☐ Base material fracture ☐ Corrosion
- ☐ Longitudinal Weld ☐ Other *(Specify)* ______________
- ☐ Girth weld
- ☐ Other field weld

TYPE OF REPAIR

Pipe

- ☐ Weld over sleeve ☐ Replace pipe (length) ______________ feet
- ☐ Patch welded
- ☐ Clamp ☐ Other repair or disposition *(Specify)* ______________

component

- ☐ Replaced ☐ Other *(Specify)* ______________
- ☐ Reconditioned

Location of leak or failure

- ☐ Within building ☐ Below other paved area *(Specify)* ______________
- ☐ Aboveground ☐ Below walkway
- ☐ Below ground ☐ Below road
- ☐ Below water ☐ Paved ☐ Median or unpaved

Depth of cover ______________ inches

Soil information at pipe depth (1)☐ Soil (2)☐ Rock

Estimated soil temperature at point of leak ______________ ^{o}F

CORROSION

GENERAL CORROSION INFORMATION

Location	Description	Cause	
☐ Internal corrosion	☐ Pitting	☐ Galvanic	☐ Stray current
☐ External corrosion	☐ General	☐ Bacterial	☐ Other *(Specify)* ______________

GENERAL CORROSION INFORMATION

Coating	Method of application	Material	
☐ Bare	☐ Mill coated	☐ Coal tar	☐ Thin-film coatings
☐ Coated	☐ Yard coated	☐ Asphalt	☐ Other *(Specify)* ______________
☐ Wrapped	☐ Field coated	☐ Wax	
Year installed ______________	☐ Unknown	☐ Prefabricated film	

CAUSE OF COATING FAILURE

- ☐ Damage ☐ Other *(Specify)* ______________
- ☐ Defective material
- ☐ Defective application
- ☐ Decomposition

CATHODIC PROTECTION

- ☐ Yes
- ☐ No

Year started ______________

Type

- ☐ Impressed
- ☐ Galvanic
- ☐ Other *(Specify)* ______________

ph OF SOIL NEAR LEAK ______________

SOIL RESISTIVITY

Last soil resistivity measurement in the area of the leak

______________ (ohm-cm)

Date of measurement Distance from leak *(feet)*

PIPE-TO-SOIL POTENTIAL

Last pipe-to-soil potential measurement at nearest points on each side of the leak ______________ *(volts)* and ______________ *(volts)*

Distances from leak to each measurement point Date of measurement ______________

______________ *(feet)* and ______________ *(feet)* At leak ______________ volts

PROCEDURES FOR RECORDS REVIEW AND FIELD INSPECTION LEAKAGE SURVEY

Distribution System

Owner/Operator ______________________________

Location ______________________________

Date(s) of Survey ______________________________

Method of Survey

_____ Combustible Gas Indicator (CGI)

_____ Flame Ionization (F/I)

a) _____ Portable

b) _____ Mobile

_____ Vegetation

_____ Other (specify) ______________________________

Leak Survey Reports

Leak Classification

Grade 1 ____________ Number

Date and Time Reported for Grade 1 Leaks Only

Leak Number	Date	Time

Grade 2 ____________ Number

Grade 3 ____________ Number

Remarks ______________________________

____

Person Performing Survey ______________________________

Form 103.1

PATROL RECORD

Period Covered: Began ______________________ Ended ______________________

Areas Covered: ______________________

____

Map References: ______________________

____

Leakage Indications Discovered (describe locations and indications, such as condition of vegetation): ______________________

____

____

____

Leakage Indications Reported to: ______________________

Construction Activity Along Areas: ______________________

____

____

Describe any unusual conditions at highway and railroad crossings: ______________________

____

____

____

Other factors noted which could affect present or future safety or operation of gas system: ______________________

____

____

Follow-Up (repairs, maintenance or tests resulting from this inspection): ______________________

____

____

____

COMMENTS: ______________________

____

____

____

No. of persons in patrol party: ______________________

Signature of person in charge of patrol party:

____

Date: ______________________

Form 104.1

______________ Gas Company

______________ ______________

(If you are not **POSITIVE**, leave answer blank.)

REPORT FOR SCHOOLS AND HOSPITALS

Date: ______________ 19 ____

Name of Building: ______________ Town: ______________

Location: ______________ Inspectors: ______________

Check List:

1. Supply Main: Average Pressure ______________ Location ______________

   Method of Leak Test: ______________ Results: ______________

   ____

2. Service Line: Size ______________ Location ______________

   Method of Leak Test: ______________ Results: ______________

   ____

   Entrance Above or Below Ground? ______________ Is Meter Stop Accessible and in Good Order? ______________

   ____

3. Meter: Make ______________ Size ______________ Number ______________

   Location: ______________

   Case & Fittings Tested for Leaks? ______________

   Method: ______________ Results: ______________

4. Regulators: Make ______________ Size ______________ Number ______________

   Delivery Pressure: ______________ Vented Properly? ______________ Diaphragm ______________

   Case Vented to Outside? ______________ Relief Valve Make ______________

   Size ______________ Were Regulator and Fittings Tested for Leaks? ______________

   Results: ______________

   Indication of Leakage on Meter with Appliance Off? ______________

Signed: ______________

Form 105.1

REGULATOR INSPECTION REPORT

______________________________ ______________________________
Location Date

______________________________ Orifice Size ______________

Make: ______________ Type: ______________ Size: ______________

Pressure Rating: Inlet ______________ Outlet ______________

M. A. O. P. of System to Which it is Connected ______________

Operating Pressure: Inlet ______________ Outlet ______________

Lock Up Pressure: ______________

Monitoring Regulator or Relief Setting: ______________

Was the Regulator Stroked (To Fully Open)? Yes ________ No ________

General Condition of Station

Atmospheric Corrosion: Yes ________ No ________

Support Piping Rigid: Yes ________ No ________

Station Guards: Yes ________ No ________

Area Clean of Weeds and Grass: Yes ________ No ________

Capacity at Inlet and Outlet Pressure: ______________

Corrections Made: ______________

Remarks: ______________

____

Inspector ______________
(Signed)

Sample
RELIEF VALVE INSPECTION REPORT

Owner/Operator ____________________ Date __________

Location ____________________

____

Make ____________________

Type ____________________

Size ____________________ Orifice Size __________

Type of Loadings:

Spring __________ Pilot __________ Other __________

Range ____________________

Pressure Setting ____________________

Connection Pipe Size ____________________

Vent Stack Size ____________________

Capacity ____________________

Condition of:

Relief Valve ____________________

Recording Gauge ____________________

Support Piping ____________________

Station Guard ____________________

General Area ____________________

Repairs Required ____________________

____

Repairs Made ____________________

____

Remarks ____________________

____

Inspector ____________________
(Signed)

Sample

Form 106.1

DISTRIBUTION LINE VALVE INSPECTION REPORT

Valve No. ______

Owner/Operator ______

Location (Town or County) ______

Mfg'r. Name ______ Serial No. ______

Type/Model ______ Connection ______

Size ______ *Pressure Rating ______ psig

*Location ______ ______ Underground ______ Aboveground

______ Valve Box ______ Manifold

*Date Valve Inspected ______

PHYSICAL INSPECTION

*Valve Box Accessible ______ Yes ______ No

*Valve Stem Accessible ______ Yes ______ No

*Valve Stem Rotated ______ Yes ______ No

*Valve Position Left ______ Open ______ Closed

Gas Leaks Found ______ Yes ______ No

Valve Lubricated ______ Yes ______ No ______ Not Necessary

*Valve Condition:

Surface ______ Smooth ______ Pitted

Coating ______ Good ______ Bad ______ Not Coated

Painted ______ Good ______ Needs Painting

Repairs Required ______

______ W. O. Number(s) ______

*Repairs Made/Date(s) Completed ______

Remarks ______

Inspector ______ (signed) Approved ______ (signed)

*Important Items

Form 107.1

Sample

TRANSMISSION LINE VALVE INSPECTION REPORT

Valve No. ___________

Owner/Operator ___________

Location (Town or County) ___________

Mfg'r. Name ___________ Serial No. ___________

Type/Model ___________ Connection ___________

Size ___________ *Pressure Rating ___________ psig

*Location ___________ ___________ Underground Aboveground

___________ Valve Box ___________ Manifold

*Date Valve Inspected ___________

OTHER THAN OFFSHORE

*1) Block Valve Spacing

*Class 1 Location Adequate	____ Yes	____ No
*Class 2 Location Adequate	____ Yes	____ No
*Class 3 Location Adequate	____ Yes	____ No
*Class 4 Location Adequate	____ Yes	____ No

*2) Block Valve Requirements

*Valve Accessible	____ Yes	____ No
*Valve Operating Device Accessible	____ Yes	____ No
*Valve Operating Device Protected from Tampering and Damage	____ Yes	____ No
*Valve Protected from Tampering and Damage	____ Yes	____ No
*Valve Supported Adequately	____ Yes	____ No
*Valve Operable	____ Yes	____ No
*Valve Operating Device Operable	____ Yes	____ No
*Valve Position Left	____ Open	____ Closed

*Important Items

ODORIZATION SNIFF TEST RECORD

4 Times per Year

Operator Name ______________________________

Location (Operator) ______________________________

Date of Test ______________________________

Time of Day ______________________________

Person Performing Test ______________________________

Address of Facility Where Test Was Conducted ______________________________

____

Identify equipment used for test, such as range, water heater, space heater, or meter loop ______________________________

____

Odor Intensity Rating:

1. Absent ____________
2. Barely Detectable ____________
3. Readily Detectable ____________
4. Strong ____________
5. Obnoxious ____________

METER ODORANT CONCENTRATION TEST

Instrument Used: ______________________ Serial No. ______________________

Location of Test ______________________ Test Date ______________________

Distance from Odorizer _______________ miles Test Time ______________________

Percent gas in odorometer effluent (from meter chart) when first detected (threshold value) (0 - 1%): __________ %

ODORANT CONCENTRATION AT 1% GAS IN AIR

Odor Intensity Rating: Evaluator: ______________________

1. Absent
2. Barely Detectable
3. Readily Detectable
4. Strong
5. Obnoxious

Witnesses: ______________________

____

METER ODORANT CONCENTRATION TEST

Instrument Used: ______________________ Serial No. ______________________

Location of Test ______________________ Test Date ______________________

Distance from Odorizer _______________ miles Test Time ______________________

Percent gas in odorometer effluent (from meter chart) when first detected (threshold value) (0 - 1%): __________ %

ODORANT CONCENTRATION AT 1% GAS IN AIR

Odor Intensity Rating: Evaluator: ______________________

1. Absent
2. Barely Detectable
3. Readily Detectable
4. Strong
5. Obnoxious

Witnesses: ______________________

____

Form 108.3

MONTHLY ODORIZATION REPORT

Month of ____________________

Period __________ to __________

RRC I. D. No. ____________________ Area ____________________

Odorizer Location ____________________

Kind of Odorizer ____________________ Tank Capacity __________ gals. or lbs.

Brand Name of Odorant Used ____________________

ODORANT USAGE

1. Odorant in Tank First of Month ____________________
2. Odorant Added During This Month ____________________
3. Total Odorant to Account for (Items 1 + 2) ____________________
4. Odorant in Tank End of Month ____________________
5. Odorant Used During Month (Items 3 - 4) ____________________
6. Gas Delivery This Month ____________________
7. Rate of Odorization in lbs. or gals./MMcf* ____________________ MMcf

$$\frac{\text{Odorant Used in lbs./gals.}}{\text{Gas Delivery in MMcf}} \quad \frac{\text{(Item 5)}}{\text{(Item 6)}}$$ __________ lbs. or gals./MMcf

Superintendent ____________________

*MMcf means Million Cubic Foot

Form 109.1

LEAK COMPLAINT

RECEIVED BY ________________ DATE ________________ # ________________

TIME RECEIVED ________________ am/pm TIME DISPATCHED ________________ am/pm

NAME ________________ ADDRESS ________________

REPORTED BY:

___ Public (name) ________________

Phone number ________________

___ Company Employee ________________

___ Police or Fire Department

___ Other ________________

APPARENT LOCATION OF LEAK:

___ Inside House

Location ________________

___ Customer yard line

___ Company line

___ Meter or regulator

___ Other ________________

NATURE OF COMPLAINT:

___ Gas Odor

___ Check for fumes

___ Construction damage

___ Visible or audible leak

___ Other ________________

CUSTOMER WAS ADVISED:

___ Not to switch lights or appliances on or off

___ To turn off gas

___ Other ________________

COMMENTS: ________________

____

LEAK INVESTIGATION

TIME ARRIVED ________________ am/pm TIME COMPLETED ________________ am/pm

Were there any leaks? Yes ___ No ___ Leakage amount ________ Cu. Ft./________ min.

HOW WAS INVESTIGATION MADE?

Shut-in test ___ Soap test ___ Detector ___

Leak classification: Hazardous ___ Non-hazardous ___

Was meter tested for proper operation? Yes ___ No ___

Meter left On ___ Off ___ Blind disk installed Yes ___ No ___

Meter locked Yes ___ No ___ Meter insulated Yes ___ No ___

Did gas have a distinctive odor? Yes ___ No ___

Customer advised to call plumber Yes ___ No ___

LEAK LOCATION:

___ Customer piping

___ Appliance

___ Company Line

___ Meter

___ Regulator

___ Fitting

___ Other ________________

COMMENTS: ________________

____

____

____

____

____

RESOLVED BY: ________________ DATE ________________

Form 109.1A

LEAK INVESTIGATION ORDER

No. ____________________

1 REPORTED BY
- A Leak Inspector
- B Other Co. Employee
- C Customer/Occupant - - - -
- D Police/Fire Dept.
- E Person Causing Damage*
- F Other*

Date ____________ Time ____ : ____ am pm Address: ______________________________

Prepared By ______________________ Town: ______________________________

Name ____ Tel. No. ____________

Name* ______________________ Title, etc. ____________________ Tel. No. ____________

Meter Location (if known) ______________________

2 NATURE OF COMPLAINT
- A Construction Damage
- B Vegetation Damage
- C Visible/Audible Leak
- D Gas Odor
- E Fumes
- F Other ____________

3 REPORTED LOCATION

A OUTSIDE BLDG.
- 1 Gen. Odor in Air
- 2 at Meter
- 3 at Alley
- 4 at Street
- 5 Other ____________

B INSIDE BLDG.
- 1 Odor Throughout
- 2 In Kitchen
- 3 at Water Heater
- 4 at Furnace
- 5 Other ____________

4 Emergency Action Advised — A Yes - - 1 Evacuate, vent, operate no switches, etc. 2 Turn Gas Off 3 Other ____________; B No

5 Notified Fire Department — A Yes; B No

Other Information ______________________________

Order Dispatched to ______________________ at ____ : ____ am pm

INVESTIGATION DATA (Con't. on back)

A Investigator Arrived at ____ : ____ am pm

CGI Checked for proper operation — Make/Model ____________ Serial # ____________

Emergency Action - -
- had not been advised
- which was advised HAD been taken
- which was advised HAD NOT been taken

If leak was reported at a specific outside location (i.e., at street, alley, etc.), *the investigation may begin in H.* In ALL other cases begin investigation below.

CGI check for gas in atmosphere ______ % Gas

DOES approach or exceed 4.5% Gas - - Proceed to E on back

Does NOT approach or exceed 4.5% Gas - Continue in A on back

H *Leak was reported at specific outside location (street, alley, etc.)*

CGI/Bar test ______ % Gas at Grade ______ Leak on ____________

Prepared Leak Report

CGI/Bar test in the vicinity — CGI readings near buildings in the vicinity were —
- *POSITIVE — Proceed with FULL investigation in A at left!*
- *Negative — NO leakage near building - - Proceed to D and complete order by entering appropriate information*

INVESTIGATION DATA (Con't. from front)

A (con't.) — Gas in atomsphere does Not approach/exceed 4.5% Gas

Turn Gas Off — LP Service Test Regulator—Set ____ oz. Lock-up ____ oz.

Low Flow Meter Tag - - - Registers OK Odorant Detected

Non-Register — Replace Meter

Install Meter # ____________ *Low Flow Retest OK*

Meter Test House Pipng for ______ Minutes Leakage Rate ______ CFH

Soap Test Meter Set - - - No Leaks Leak Repaired (Show in D)

Stand-up pressure test ________ *minutes at* ______ psi oz. *loss* ______

Last Leak Test Indicated
- No Leak in House Piping — Proceed to C
- Leak in House Piping—Continue in B

B Leak in House Piping

Soap Test - -
- Leak Located — Leak Repaired—Meter Retest OK
- Leak Not Located — Advised Cust. to have leak rep'd

Continue in C

C Main & Service Line

CGI/Bar Test — Customer SL ____ % Company SL ____ % Main ____ %

No Leak Found

Found a Grade ____ Leak Prepared Report ____________

Continue in D

E *Gas in Atmosphere DOES approach or exceed 4.5% Gas*

Evacuate Building ____________ persons *Turn Gas Off*

Drain House Piping *Vent Building*

Recheck for Gas in Atmosphere ____________

Hazardous Condition Eliminated — Resume Investigation in A

Hazardous Condition Still Exists (Continue in F)

F *Contacted Supervisor ____________ for assistance*

CGI/Bar test of Cust. SL, Co. SL Mains (Record results in C)

CGI check of sewer vents indicated ____________ % Gas

Leak source found: Hazard Eliminated (Resume Investigation in A

G *Fume Complaints & Cases where complaint source not yet determined*

Appliances checked for fumes
Other sources ck'd for fumes *Found* ____________

Fume Source
- *Determined (Proceed to D — Show action taken)*
- *Not Determined — CO_2 Test* *Positive* *Negative**

**If source not determined — Contact Supvr* ____________

D Completed Report

Source of Complaint
- Not yet determined — *Con't. Investigation in G*
- Determined to be - - Leak on piping carrying - - - Unmeas. Gas / Measured Gas; Other (explain)

Gas Left On Meter Sealed Meter Removed

Work Done & Instructions Given ______________________________

METER DATA
(At time of arrival)

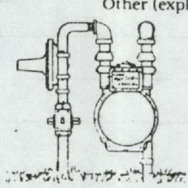
Size/Kind ____________

Mtr. # ____________

Reading ____________

Mtr. Change Order Req'd.

Insulator Check OK



Leak Location

I hereby certify that the work described above has been done and I acknowledge receipt of the above instructions.

Completed by ______________________ at ____ : ____ am pm ____/____/____ *Customer Signature* ____________

Form 110.2

____________________ Gas Company

________________, ____________________

ATMOSPHERIC CORROSION CONTROL INSPECTION

This form to be completed when aboveground piping is inspected for corrosion from atmospheric conditions or corrosive conditions that can not be controlled by cathodic protection. Inspect all exposed piping every three years for atmospheric corrosion. 192.479, 192.481, 192.491

Date: ________________, 19 ___

1. Location: ________________________________

2. Name of Inspector: ________________________________

3. Designation of Line: Trans. ____________ Dist. ____________ Service ____________

4. Line Size: ________________

5. Area of corrosion: Pipe ____________ Meter Set ____________ Fitting ____________

   Regulator ____________ Support ____________ Vent ____________

   Other ________________________________

6. Corrective measures taken: Painted ____________ Coated ____________ Other ____________

   Type of paint or coating used: ________________________________

7. If general painting of exposed piping is undertaken, list addresses:

Form 111.1

CATHODIC PROTECTION SHEET

Location: ______________

Tests By: ______________

For Year: ______________

Test Location Number	TEST LOCATION	Soil Resist. OHMS/CC	Pipe to Soil Reading (– Volts) 1st Qtr. Mo. ____	2nd Qtr. Mo. ____	3rd Qtr. Mo. ____	4th Qtr. Mo. ____	REMARKS

Form 112.1

CORROSION CONTROL

RECTIFIER INSPECTION
(2 Month Intervals)

Line Operator ______________________________

Location ______________________________

Rectifier Brand ______________________________

Serial No. ______________________________

Date	Supply Voltage	Output Volts	Output Amps	Rectifier Condition	Remarks

Form 113.1

_________________________ Company

_________________________ , _________________________

Pipeline Test Report

This form must be completed for each section of newly installed pipe or service line and on each service line that is disconnected from the main and reinstated for any reason.

Date _________________ , 19 ______

Type of Pipe _________________________

Size of Pipe _________________________

Length of Line _________________________

Location of Line _________________________

____

____

Tested With Nitrogen ______ Air ______ Natural Gas ______ Water ______ Other ______

____

Time Started _________________________

Time Stopped _________________________

Test Pressure Start _________________________

Test Pressure Stop _________________________

Line Loss _________________________

Reason For Line Loss _________________________

____

____

Corrective Measures Taken _________________________

____

____

Signed By _________________________
Person Making Test

Sketch location on back of this sheet for mapping purposes.
Use actual measurements and adequate reference points.

Appendix F

Sample Emergency Plan

Introduction

This emergency plan provides a sample format of data essential in an emergency situation.

No emergency plan can cover all situations. There is no substitution for the sound judgment of the person or persons involved. In any emergency, the safety of the public MUST ALWAYS BE FIRST PRIORITY.

Before any emergency arises, you have the responsibility to develop an emergency plan to meet your unique system. In addition, everyone responsible for handling an emergency situation should be familiar with the contents of that plan. It is your responsibility, as the operator, to provide this training.

A. **Definition of Emergency Incident**

An emergency condition exists when **you** (or your representative) determine that extraordinary procedures, equipment, manpower, and/or supplies **must be used to protect the public from existing or potential hazards**. These hazards may include, but are not limited to:

1. Facility failures that result in:
    a. Underpressure in the system;
    b. Overpressure in the system;
    c. Large amounts of escaping gas;
    d. Fire, explosion, etc.;
    e. Any leak considered hazardous; and
    f. Danger to major segment(s) of the system.
2. Natural disasters (floods, tornadoes, hurricanes, earthquakes, etc.).
3. Civil disturbances (riots, etc.).
4. Load reduction conditions (result in voluntary or mandatory reduction of gas usage).

B. **Contents of Emergency Plan**

1. Emergency Notification List
2. Map of Key Valve Locations
3. Emergency Equipment
4. Responding to Gas Leak Reports and Interruption of Gas Service
5. Major Emergency Check List
6. Reporting Requirements (Telephone Report)
7. Restoration of Gas Service Because of Outage

SAMPLE

EMERGENCY NOTIFICATION LIST

OWNER ______________________________

1. Owner's Operating Personnel:

NAME	ADDRESS	PHONE NO.	EQUIPMENT AVAILABLE

2. Others to Notify:

AGENCY	LOCATION	PHONE NO.
Police		
Sheriff		
Hwy Patrol		
Fire		
Civil Defense		
Mutual Aid Gas Systems:		
Gas Supplier		
Pipeline Contractors:		
All Night Service Stations:		
Other		
Railroad Commission		

8. Education and Training
9. Accident Investigation

Complete plan — post appropriate charts in conspicuous place.

2. **Map of Key Valve Locations**

Use a system map that shows key valves, system pressures, and source of supply. Keep this map readily available in an easily accessible emergency file. Be sure your employees know its contents and location.

Remember: A gas distribution system is usually a complex network of interconnected mains. They are fed by regulators and have valves throughout for shutting off or diverting the flow of gas. Pressure in the mains may vary from a few pounds to hundreds of pounds. Improper operation of a valve may create a hazardous condition, or make a hazardous condition worse.

Teach your personnel, because ONLY properly authorized personnel should operate valves. Fire, Police, other officials, or other outside individuals ARE NOT AUTHORIZED to operate OR TO INSTRUCT OTHERS, including gas company personnel, to operate valves (except "end-use" valve, commonly called the meter shut-off).

3. **Emergency Equipment**

Operator, or his representative, shall be responsible for the adequacy, availability, and condition of emergency equipment.

(State here the location of such equipment as key valves, maps and records, etc., necessary to adequately meet emergency conditions, such as shutoff tools, backhoe, shovels, leak repair equipment, air compressor, and jack hammer)

Periodic checks of emergency equipment should be taken and records of these inspections kept on file.

Location and address where additional manpower, equipment, and supplies may be obtained.

4. **Responding to Gas Leak Reports and Interruption of Gas Service**

It is the operator's responsibility to make sure the proper employees are familiar with procedures concerning gas leak calls and reports.

a. The employee receiving a report of a gas leak should get as much of the information as possible to properly fill out the leak report form (Form 109.1, 109.1A). Use common sense --saving human life is the first consideration.

b. All reports of leaks on consumer premises get priority. LEAKS INSIDE A BUILDING GET TOP PRIORITY.

c. After getting the information, and determining that a hazardous leak exists inside a building, remind the customer of all the following information: (It is your responsibility to have taught this earlier.)

   (1) No one is to turn ON or OFF any electrical switches.

(2) No one is to ring door bells or use the phone.

(3) Extinguish all open flames. DO NOT LIGHT MATCHES, CIGARETTES, etc.

(4) Turn off gas supply, if feasible.

(5) Everyone in the building is to leave the building and go a safe distance (about a block) away. GO ON FOOT — no engines or sparks.

d. Dispatch necessary personnel to the location of the reported leak.

e. DUTIES OF FIRST COMPANY EMPLOYEE ON THE SCENE:
TAKE EVERY CORRECTIVE ACTION NECESSARY TO PROTECT LIFE AND PROPERTY FROM DANGER (IN THAT ORDER). IT IS THE RESPONSIBILITY OF THE PERSON IN CHARGE TO:

(1) Set up communication.

(2) Coordinate the operation.

(3) Make all decisions concerning emergency valves (isolating areas) and the use of emergency equipment.

(4) Implement the check lists. (See following pages.)

(a) Leaks Outside Building

(b) Leaks Inside Building

(c) Gas Burning Inside Building

(d) Interruption in Gas Supply

Minimum Response Actions
For Leaks Outside a Building

1. Assess danger to public, surrounding buildings, occupants, and property.
2. Extinguish all open flames. No smoking.
3. If necessary, notify fire and police. (Natural gas master meter operators should also notify gas utility.)
4. Block street.
5. Notify supervisor or other responsible persons.
6. Bar hole next to foundation of building.
7. Check neighboring buildings for gas.
8. Implement Check List.
9. Repair leak.
10. If you are **positively sure** it is safe, return occupants to building.

Minimum Response Actions
For Leaks Inside a Building

1. Evaluate house immediately to determine concentration of gas and source of leak. Evacuate if necessary.
2. DO NOT operate any electrical switches.
3. DO NOT use phone.
4. Shut off gas meter valve.
5. If more than four percent gas present, open doors and windows, ventilate building.
6. Bar hole area especially around foundation. Check water meter and other openings.
7. If ground is gas free and if house is gas free, turn on meter valve. CHECK ALL GAS PIPING AND APPLIANCES FOR LEAKS. (Is meter hand turning normally or spinning? Soap bubble test.)
8. Implement Check List.
9. Repair leak.
10. If leak cannot be repaired, notify customer. Turn off meter, lock it, tag it, and leave.

Minimum Response Actions
For Gas Burning Inside Building

1. Call fire department.
2. Master meter operators should also call local gas utility.
3. If fire is at an appliance, shut gas off at appliance valve.
4. If not possible, shut gas off at meter or curb valve.
5. If fire continues, bar hole area and use CGI to locate source of gas.
6. Implement Check List.

Minimum Response Actions
For Interruption In Gas Supply

An interruption to gas supply line could be due to: (a) freezing of the regulators; (b) break in line; (c) sabotage; (d) supplier cut off; or (e) LP-gas tank out of fuel.

1. Call your supplier (transmission company, natural gas utility, or LP-gas distributor).
2. Locate leak. Inform supplier of the location of leak, if possible.
3. Close appropriate valve in your system to isolate the break (if necessary).
4. Implement Check List.
5. Major Emergencies

Major Emergency Check List

____ 1. Has fire department been called?

____ 2. Have persons been evacuated and area blockaded?

____ 3. Has police department been notified?

____ 4. Has repair crew been notified?

____ 5. Has company call list been executed?

____ 6. Have communications been established?

____ 7. Has outside help been requested?

____ 8. Have ambulances been called?

____ 9. Has leak been shut off or brought under control?

____ 10. Has civil defense been notified?

____ 11. Have emergency valves or proper valves to shut down or reroute gas been identified and located?

____ 12. If an area has been cut off from a supply of gas, has the individual service of each customer been cut off?

____ 13. Is the situation under control and has the possibility of reoccurrance been eliminated?

____ 14. Has surrounding area, including buildings adjacent to and across street from, been probed for the possibility of further leakage?

____ 15. Has proper tag been put on meter?

____ 16. Has telephone report to RRC been made?

____ 17. Has telephone report to MTB/DOT been made?

____ 18. Has news media been informed (if necessary)?

Date ______________________________

PIPELINE SAFETY NOTICE

To Report Pipeline Accidents Involving

GAS or HAZARDOUS LIQUIDS

CALL

(512) 447–2171

24-HOUR EMERGENCY NUMBER

FOR REPORTABLE GAS SEE: 16 TAC §7.70(g)

FOR REPORTABLE HAZARDOUS LIQUIDS
(other than crude oil) see: 49 CFR 195.52 and 16 TAC §7.84(a)

WITHIN TWO HOURS OF DISCOVERY, notify the Commission by telephone and file a written report within 30 days on forms supplied by the Department of Transportation.

Railroad Commission of Texas, Gas Utilities Division, Pipeline Safety Section,
P. O. Drawer 12967, Austin, Texas 78711-2967

FOR REPORTABLE CRUDE OIL INCIDENTS SEE:
49 CFR 195.52, 16 TAC §§ 3.20(a) & (b), 3.66(a)(19), and 7.84(a)

WHEN REPORTING CRUDE OIL INCIDENT, CALL NEAREST OIL & GAS DIVISION DISTRICT OFFICE:

DISTRICTS 1 & 2 - San Antonio
(512) 227-1313

DISTRICT 3 - Houston
(713) 460-0631

DISTRICT 4 - Corpus Christi
(512) 242-3113

DISTRICTS 5 & 6 - Kilgore
(214) 984-3026

DISTRICT 7B - Abilene
(915)677 - 3545

DISTRICT 7C - San Angelo
(915) 653-6776

DISTRICT 8 - Midland
(915) 684-5581

DISTRICT 8A - Lubbock
(806) 744-6944

DISTRICT 9 - Wichita Falls
(817) 723-2153

DISTRICT 10 - Pampa
(806) 665-1653

Figure 26

6. **Reporting Requirements** (Telephone Report)

a. The Railroad Commission of Texas must be notified as soon as practicable by telephone for any leak that:

(1) Caused a death or an injured person required hospitalization;

(2) Caused total property damage of $5,000 or more (including the cost of gas lost);

(3) Was significant in the judgment of the operator, even though it did not meet the other criteria.

b. A telephone call must be made to the DOT for any incident that:

(1) Caused a death or an injured person required hospitalization;

(2) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more;

(3) Resulted in the shutdown of an LNG facility;

(4) Could have resulted in a significant incident or was a significant incident to the operation, in the judgment of the operator (even though it does not meet the criteria of the above requirements).

c. The telephone report to RRC and/or DOT should contain:

(1) Names of operator and person making report and their telephone numbers.

(2) The location, time, and date of incident.

(3) Fatalities and personal injuries.

(4) All other significant known facts that are relevant to the cause of the leak or extent of the damages (describe accident).

(5) Who in management should be contacted upon arrival at accident.

The telephone report, if required, should be made at the **earliest practicable moment** following discovery and at least within two hours. To notify RRC, call (512) 447-2171 (See Figure 26). To notify DOT, call (202) 426-0700. The National Response Center (NRC) will take your phone call.

7. **Restoration of Gas Service Because of an Outage**

When the supply of gas has been cut off to an area, no gas will be turned on to the affected area until the individual service to each customer has been turned off.

A house-to-house operation is mandatory. The individual service of each customer must be turned off, either at the meter or at service valves. If the service valves cannot be located, the service line must be uncovered, a service valve installed, and then cut off. In restoring service to an affected area, all gas piping and meters must be purged and appliances relighted. Never turn on gas at a meter unless you have access to ALL appliances on the consumer piping. In the event a customer is not at home, a card must be left in a conspicuous location requesting the customer to call the gas company to arrange for restoration of service.

The person in charge is to coordinate this operation and be responsible for same.

A complete record of the incident, with drawings, etc., shall be kept on file.

8. **Education and/or Training**

a. Employee Training

Employees must be periodically trained in emergency procedures, including but not limited to:

(1) Update of Emergency Manual (Plan).

(2) Review of employee responsibilities in an emergency.

(3) Review of location and use of emergency equipment.

(4) Review the locations and use of:

(a) System maps.

(b) Main records.

(c) Service records.

(d) Valve records.

(e) Schematics.

(f) Properties of natural gas and LP-gas.

(5) Take a hypothetical emergency situation and STEP BY STEP review the action to be taken, including public officials, firemen, police, local gas utility, etc.

(6) Record keeping.

(7) Telephone reports to RRC and DOT.

(8) Records shall be kept on file of attendance and items discussed.

b. **Public Education**

There shall be a continuing education program to teach customers, the public, appropriate governmental organizations, and persons engaged in excavation-related activities to recognize a gas emergency. Instruct in reporting it to the gas company. The program material shall include but not be limited to:

(1) Information about gas properties.

(2) Recognition of gas odors.

(3) What to do and not to do when there is a strong gas odor.

(4) Notification of the gas company prior to making excavations or excavation-related activities.

(5) Gas company phone number and after hours number to call for information or to report an emergency.

NOTE: There are many excellent pamphlets published by state and regional gas associations, by the American Gas Association, the Southern Gas Association, and by TGA, Inc., regarding properties of gas and emergency information. This information can be obtained from these organizations at no cost or for a small nominal charge. See Section VII of this guideline for addresses and telephone numbers.

This information may be conveyed to the public by:

(1) Radio and television (if applicable).

(2) Newspapers including apartment or condominium newsletters.

(3) Meetings.

(4) Bill stuffers.

(5) Mailings.

(6) Hand-outs.

(7) Postings on bulletin boards.

If you have customers who do not speak English, you must get this same information to them in their language so that they can understand it.

A record shall be maintained of the public education program and related activities.

c. **Liaison with Public Officials and Local Gas Utilities**

Establish liaison with fire, police, civil defense, and medical officials with respect to emergency procedures. Master meter operators should develop an emergency guideline.

A RECORD MUST BE KEPT OF ALL MEETINGS, TRAINING SESSIONS, AND OTHER RELATED ACTIVITIES, such as:

(1) Training sessions in proper procedures to follow during a gas emergency.

(2) Meetings to learn capability, responsibility, and procedures respecting gas emergencies of each group above.

d. **Information to News Media**

During an emergency, refer all information requests to person coordinating emergency actions. Suggest plan of public announcement:

(1) Calm any unfounded fears.

(2) Do not make reckless comments.

(3) Tell precisely what the public can do to help.

(4) Tell specifically what the gas company is doing about it.

(5) Give the facts to prevent baseless rumors.

(6) Repeat most encouraging view of situation that facts will permit.

(7) Do not speculate regarding the situation in absence of facts.

9. **Accident Investigation**

Each operator shall establish procedures for analyzing accidents and failures, including the following:

a. **Investigation of all company facilities to determine if accident was gas related.**

(1) Leak survey.

(2) Pressure tests of piping.

(3) Meter and regulator check.

(4) Questioning persons on the scene.

(5) Examining burn and debris patterns.

(6) Odorization level.

(7) Recording meter reading.

(8) Weather conditions.

b. **Procedures to follow if accident was gas related:**

(1) Selection of samples of the failed facility or equipment for laboratory examination for the purpose of determining the causes of the failure and minimizing the possibility of recurrence.

(2) Notify insurance company.

Accident Investigation No. ______

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION

County ______

Region ______

GAS or LIQUID
(circle one)

ACCIDENT / LEAK REPORT NO. ______

PERSON RECEIVING REPORT ______

Material Transported ______
(Natural gas, crude oil, products, ammonia, etc.)

Date Reported to Commission ______
(MO/DA/YR) (TIME)

Person Making Report ______
NAME PHONE NUMBER

(Person at Location) ______
NAME PHONE NUMBER

Reporting/Operator: ______
NAME OF COMPANY OR SYSTEM

Operator's Phone Number: ______
AREA CODE/NUMBER

Date Operator Discovered or Was Notified of Accident/Leak: ______
(MO/DA/YR) (TIME)

DETAILS OF ACCIDENT/LEAK

1. When: ______
(MO/DA/YR) (TIME)
2. Where: ______
(Street Number, Street Address, City or Geo. Location)
3. Property Damage Estimates: ______
Dollar Value
4. Persons Killed: ______ Number
6. Hospital: ______ Name & City
5. Persons Injured: ______ Number
______ Extent of Injuries
7. General Description: ______
Brief Phrases of Situation and/or Conditions

______

______

______

______

______

IMMEDIATE ACTION

* ______ (______) ______
DATE TIME

______

______

______

______

______

* RECORD DATE, TIME, AND INITIAL EACH ENTRY. SKIP A LINE BETWEEN ENTRIES.

Pipeline Safety Section
Form PS-2, REV 12/87

Figure 27

NOTES

Appendix G

Manufacturers of ASTM D2513 Pipe as of March 1, 1988

1. Oil Creek Plastics, Inc.
   P. O. Box 385
   E. Titusville Road
   Titusville, Pennsylvania 16354

   Phone: (814) 827-3661

2. PLEXCO
   3240 North Mannhein Road
   Franklin Park, Illinois 60131

   Phone: (312) 455-0600

3. Phillips Driscopipe, Inc.
   A Subsidiary of Phillips
   Petroleum Company
   2929 N. Central Expressway,
   Suite 100
   Richardson, Texas 75083

   Phone: (214) 783-2666

4. Cyclops
   Tex-Tube Division
   P. O. Box 7705-7705
   1503 N. Post Oak Road
   Houston, Texas 77270

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   2929 Carlisle, Suite 300
   Dallas, Texas 75204

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7. Inner-Tight Corporation
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   Phone: (201) 376-3255

8. Poly Pipe
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   Gainesville, Texas 76240

   Phone: (817) 665-1721

9. Celanese Plastic
   4300 Hilliard Cemetery Road
   Hilliard, Ohio 43026

10. Appalacian Plastics
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    Box 16
    Glenville, West Virginia 26351

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NOTES

Appendix H

Basic Concepts of Regulators and Relief Devices

Introduction

To understand the equipment used to regulate the pressure of natural gas, you should be familiar with some fundamental physical units and concepts. Four are particularly important to regulators. Taken in pairs they are:

Pressure and Force

Flow and Throttling

A. Pressure

In the gas business the commonly used pressure units are:

psi = pounds per square inch
osi = ounces per square inch
in. w.c. = inches water column
in. Hg = inches mercury

For convenience the four are usually shortened to pounds, ounces, and inches.

While these certainly are fine, remember that pounds and ounces are actually short forms. There really is no such thing as a pound of pressure or an ounce of pressure. They are incomplete. Pressure is defined as force per unit area. Pounds and ounces express force (they also express weight). For expressing pressure the area is missing. Thus, they should be pounds per square inch and ounces per square inch.

When gas is under pressure, it exerts the given force against each unit of exposed area. For example, gas at a pressure of 10 psi pushes with a force of 10 pounds against each square inch of surface exposed to the gas. Gas at a pressure of five ounces (remember, ounces per square inch) pushes with a force of five ounces against each square inch of surface exposed to the gas.

Such units as pounds or ounces per square foot, per square yard, or other area unit are quite correct. However, for the gas business, the area unit used is the square inch. To repeat, the complete expressions are pounds per square inch (psi) and ounces per square inch (osi).

Returning to psi, there are some other forms to note as follows:

psia = pounds per square inch absolute
psig = pounds per square inch gauge

The relationship between the two is simple:

psia = psig + atmospheric pressure

Absolute pressure (psia) uses a perfect vacuum as the zero point. A perfect vacuum is 0 psia.

Gauge pressure (psig) uses the actual atmospheric pressure as the zero point. The standard pressure base for use in the State of Texas is 14.65 pounds per square inch absolute (Texas Natural Resources Code §l 91.052.)

Inches of water column or inches of mercury is often used to express the pressure being delivered to domestic customers. Pressure measurement in inches is usually done with an instrument called a manometer. (See Figure 28.) Remember these important relationships:

For inches water column
1 psig = 27.71 in. w.c.

For inches of mercury column
1 psig = 2.036 in. Hg

Note the physical limitations to pressure measurement with the manometer. The highest pressure that could be measured with a "U" type manometer, five feet high, would be only a little over two psig (56 in. w.c.). Also, note that it offers a very precise way of measuring very low pressures.

Mercury offers somewhat more range. A five foot high manometer would have a maximum of around 30 psig (61.08 in. Hg). It, too, offers accuracy. In comparison, however, compact dial-type gauges are readily and economically available for a wide variety of ranges as high as 1,000 psig and even more.

When expressing pressure in inches, it is necessary to identify the liquid. To put it another way, there really is no such thing as an inch of pressure. Instead, it is inches of some kind of liquid, and in the gas business it is generally water or mercury. Thus, the correct expressions are inches water column (in. w.c. or in. H_2O) and inches mercury column (in. Hg.). Figure 28 gives conversion factors for inches of water and mercury.

B. Pressure and Force

Force is simply a push or a pull. It is measured in pounds alone.

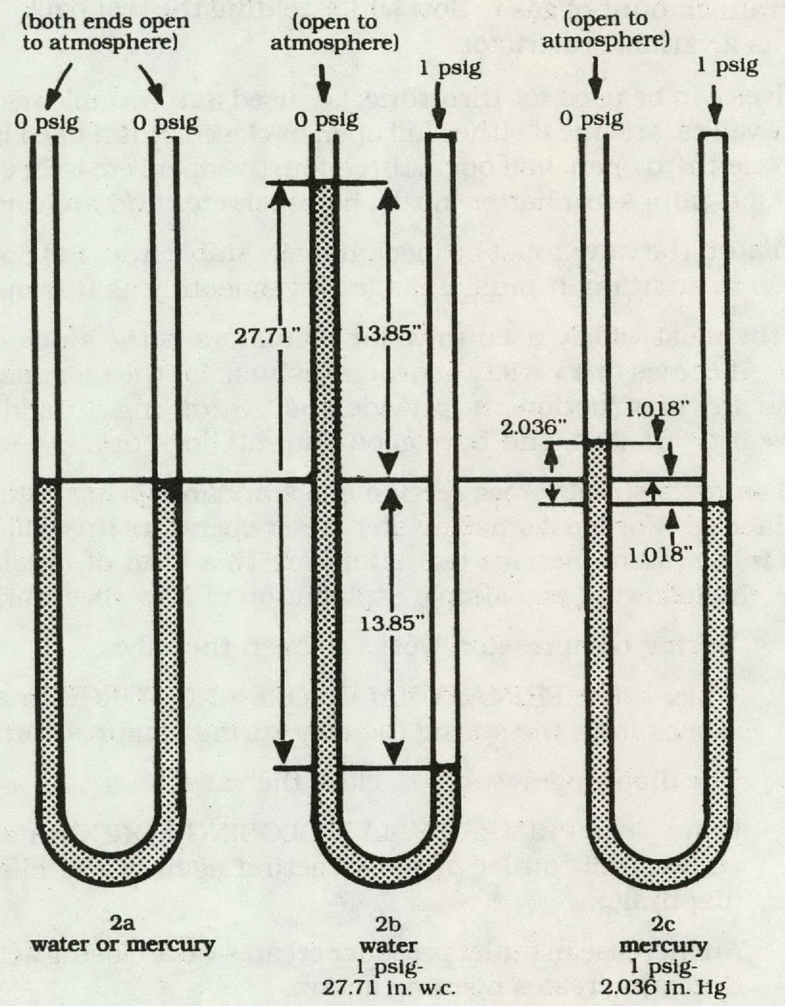
Note that pounds of pressure is incomplete (should be pounds per square inch), whereas pounds of force is complete. Thus, it would be so many pounds of pushing force or pulling force.

Figure 28A, shows the relationship between pressure and force. Note that pressure is used to create a total force. Note particularly how much force (200 pounds) can be created with only a small amount of pressure (2 psig). It is all a matter of diaphragm area or piston area. A diaphragm, of course, is simply a low friction, tightly sealed, short stroke piston (just the thing for regulators).

In Figure 28A, the effective area of the piston or diaphragm is 100 square inches (100 in.^{2}). Applying 2 psig pressure to the 100 in.^{2} area gives an upward pulling force of 200 pounds (100 in.^{2} x 2 lbs/in.^{2} = 200 pounds).

Note that the pressure above the diaphragm and the piston is atmospheric (0 psig). The differential pressure across the diaphragm and across the piston is 2 psi (2 psig - 0 psig = 2 psi).

Note also that the effective diameter of the diaphragm and the piston is only about 11 inches. An 11-inch diaphragm is not very large. This is quite a common size for regulators, particularly on commercial and industrial applications. But an 11-inch diaphragm has a large area (100 in.^{2}). It does not take much pressure (2 psig, for example) to develop quite a large total force (200 pounds).



U Tube Manometer — Water & Mercury

Figure 28

C. Flow and Throttling

To throttle the flow of a fluid is to allow only a certain amount to flow and hold the remainder back. A faucet provides a good example. How much water is wanted determines how far the faucet is opened. The faucet, a valve, is a throttling device. Depending on how far it is opened, it allows only a certain amount of water to flow and holds the rest back. It restricts flow to a certain amount.

Throttling is a basic function in a regulator. The part that throttles is a valve. It allows only a certain amount of gas to flow while holding the rest back. The valve part of a regulator is a variable restrictor.

Not all valves can be used for throttling; i.e., used as a variable restrictor. Some, like many gate valves, are fine if either full open or closed. But if used in an intermediate position (one-third open, half open, three-fourths open, etc.), they become unstable. They do such things as chatter, rattle, hammer, etc., and are unsatisfactory.

For a regulator, the valve must be mechanically stable from full open to as low a flow as possible. In addition, it must change flow smoothly as it is opened or closed.

Probably the most widely used valve for regulators is the single-port, unbalanced, globe valve. It comes in a variety of designs which, for the most part, are simple and economical in construction yet provide good throttling. In addition, they stroke freely, have little friction, and have good shut-off (lock-up).

Figure 29 shows a simple cross section of a standard spring regulator. The various parts are labeled . For most small master meter operators this will be the only type of regulator in a system. Service regulators are this kind of regulator. Referring to Figure 29, the following is a simple explanation of how they work.

1. Spring compression works to open the valve.

   Rule: The PRIMARY VALVE OPENING FORCE in a spring regulator comes from the spring (usually spring compression).

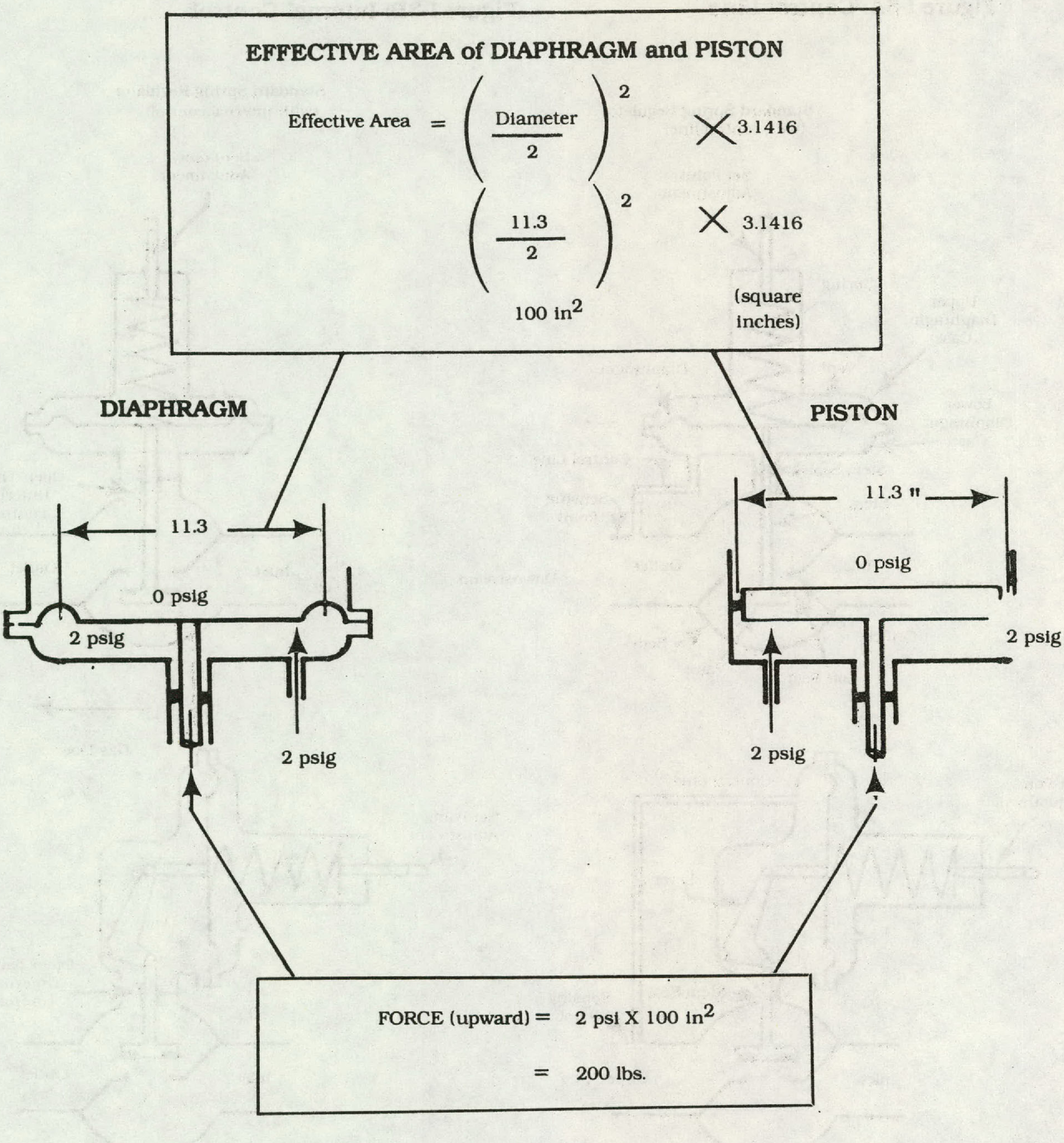
2. The diaphragm works to close the valve.

   Rule: The PRIMARY VALVE CLOSING FORCE in a spring regulator comes from outlet pressure acting against the effective area of the diaphragm.

3. An increase in outlet pressure creates valve closing action. Conversely, a decrease creates opening action.

4. Set-point (the outlet pressure a regulator is adjusted to deliver) is determined by spring compression. Turning the set-point adjustment clockwise increases spring compression which increases set-point, and vice versa.

Pilot regulators are often used at city gate stations or for large industrial customers. These regulators are somewhat more complicated than spring regulators. These types of regulators will not be discussed in this manual. A consultant should be used to select the type and proper size regulator for most situations, the exception being house regulators.



Force = Pressure X Area

Figure 28A

Typical Single Port Spring Regulators

Figure I-3A: Control Line **Figure I-3B: Internal Control**

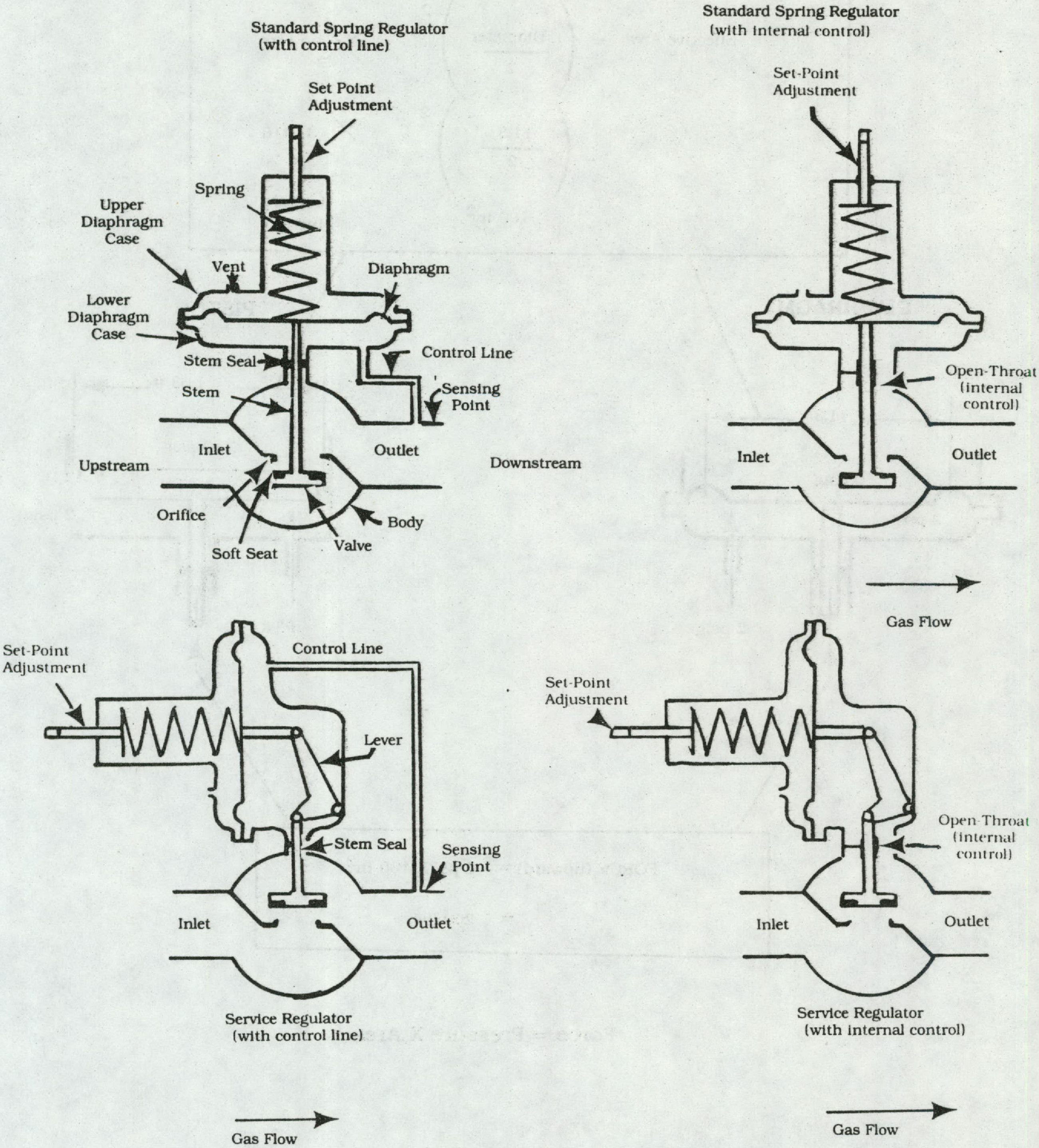


Figure 29

D. Some Basic Names and Terms

Referring to Figure 29, the **inlet** is the opening through which gas enters a regulator. The pressure of the entering gas is usually called the **inlet pressure,** although it could also be called the upstream or supply pressure.

The **outlet** is the opening through which gas leaves a regulator. The pressure of the exiting gas is usually called **outlet pressure,** although it could also be called downstream pressure.

In general, the more the inlet pressure exceeds the outlet pressure, the greater the amount of gas that can flow through the regulator, or to put it another way, the greater the capacity of the regulator. The difference between inlet and outlet pressures is sometimes called the differential across the regulator.

Piping on the inlet side is **upstream** and piping on the outlet side is **downstream.** As stated previously, a regulator takes higher pressure gas from the supply and reduces it to the pressure required by the load. To do this, something is needed on the regulator to adjust it for the specific pressure required. This adjustment is called the **set-point adjustment** and, on most of today's regulators, is a screw-type device of some kind, usually an adjustment screw. **Set-point** then is the pressure a regulator is adjusted to deliver. It is the pressure required by the load and, ithe same as the outlet pressure.

Note the **control line.** It is also called a sensing line, impulse line, equalizing line or static line. The **control line** along with the **sensing point** is a vital part of a regulator installation. They must be carefully planned and correctly installed if the regulator is to operate satisfactorily and safely.

Many regulators, particularly smaller ones, do not have the control line externally as shown in Figure 29. Instead, it is internal, and is called **internal control.** It is built into the inside in some form of open throat construction or venturi tube. However, externally or internally, every regulator has a control line or the equivalent.

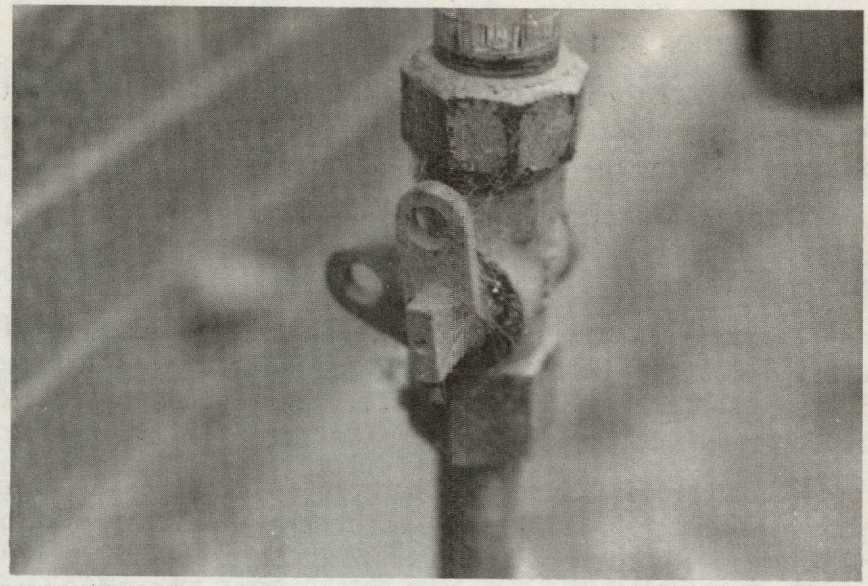
One futher point, control lines must be adequately protected against breakage because if broken, they will cause the regulator to fail. It is just that plain and serious.

Next, **the vent.** While often appearing insignificant, the vent is important to a regulator. Regulators breathe. As the internals move in the work of controlling pressure, a regulator will inhale or exhale through the vent. Therefore, the vent must be adequately protected from becoming plugged by such things as dirt, insects, ice, etc. If an obstructed vent prevents a regulator from breathing, there will be trouble.

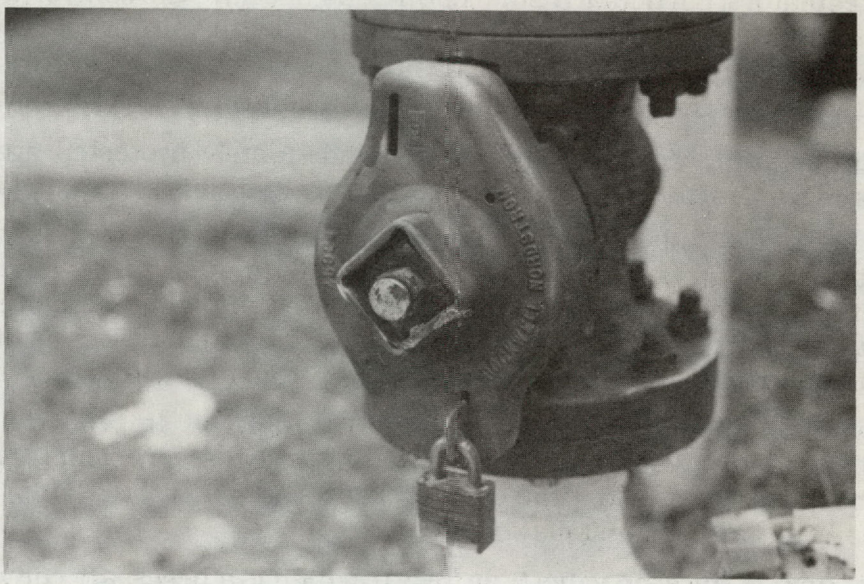
Also, water can get inside a regulator through an improperly positioned or unprotected vent. Water inside a regulator can cause problems. Therefore, vents must be positioned and protected to keep the water out. This is particularly important on outdoor installations.

The last item is the **stop valve** (Figure 30), which is a necessary convenience. There may be one or more. A simple house installation usually has only one, the stop cock. A more involved station installation would have several stop valves (inlet stop valve, outlet stop valve, control line valve, by-pass valve, and perhaps others).

The most important of all is the inlet stop valve. All should be used carefully. The inlet stop valve should be used with extra care, particularly when being opened. Do not



Stop Valve



Locked Bypass Valve

Figure 30

open it until you are sure everything is correct and ready. Then open it slowly. Allow the inlet gas to enter slowly and pressure to build up slowly, just to be sure.

Stop valves make it possible to put a regulator into service or take it out of service. They make it possible to isolate a regulator for servicing and to conduct certain tests. Correct opening and closing sequences should be adequately understood (these are often specified in gas company standards and procedures). Usage in case of an emergency should also be understood.

In most cases small operators need to rely on a consultant if a regulator station needs any major work to be done. The person who is responsible for determining when a regulator needs to be worked on should be stated in the O&M plan. The operator should list the consultant(s) in the O&M plan who is capable of working on regulator stations.

E. Overpressure Protection

There are three basic methods of providing overpressure protection:

1. Pressure Relief
2. Monitoring
3. Automatic Shutoff

Pressure relief is simply dumping excess gas to the atmosphere. The excess gas is that which would cause pressure to exceed the safety limit. Today, the relief valve is by far the most widely used piece of equipment in this category. However, liquid seals and rupture discs would also be included.

In general, relief valves can be classified in a way similar to regulators. There are two basic kinds of operation: self operation and relay operation. These can be subdivided in the same way as regulators. Furthermore, the spring relief valve is today the most widely used of all. The pilot operated type probably is next, and it offers more precise operation. It becomes more and more dominant as pressures become higher and capacities greater.

Monitoring involves a standby regulator. The standby prevents pressure from exceeding the safety limit.

Standby monitoring is the most widely used form of monitoring for the gas business. It is also called passive monitoring. Such installations consist of two regulators in series, one of which is operating to control pressure while the other is a standby. The standby unit is normally further open than necessary, usually wide open. It takes that position because it is adjusted for a higher set-point than the operating regulator. If a failure with the operating regulator causes outlet pressure to rise, the monitor takes over at its set-point and holds pressure at that valve.

There are two other forms of monitoring that are sometimes used. One simply consists of two stage regulation which, when designed for the purpose, can provide monitoring protection. The other is called override monitoring or working monitoring. With it, the upstream regulator must be pilot operated and have an extra pilot. During normal operation, the set provides two stage regulation. In an overpressure emergency it protects in the same way as standby monitoring.

Automatic shutoff involves a valve that normally remains in the wide open position and allows the gas to flow freely. It is located in series with the regulator, either upstream or downstream, depending on whether it uses a control line or internal control.

If a failure with the regulator results in a rising outlet pressure, the shutoff closes automatically when pressure reaches its set-point. It protects by shutting off the gas and remains closed until manually opened and reset.

In general, there are three primary things to consider in choosing which kind of overpressure protection to use:

1. **Continuity of Service** — Does the user, the load, continue to be supplied with gas?
2. **Containment** — Is gas released into the atmosphere or does it remain contained within the gas system?
3. **Alerting** — Is there good notification or warning that an emergency has occurred and that the overpressure protection equipment has gone into operation?

The following is a comparison of the three basic overpressure protection methods (based on the foregoing three considerations):

1. **Pressure Relief**

   a. **Continuity of Service.** In general, pressure relief valves do not interrupt gas service. They protect, while allowing gas to flow at a safe pressure. Customers continue to get gas.

   b. **Containment.** Relief valves do not contain the gas. They protect by dumping the excess gas to atmosphere.

   c. **Alerting.** Relief valves are usually good in this respect. For one thing they are noisy, particularly at full or near full blow. In addition, if the gas is odorized, the smell usually attracts attention.

   Still another indication is the rise in outlet pressure above normal. This is probably the least effective notification of all.

2. **Monitoring**

   a. **Continuity of Service.** Monitoring does not interrupt service. Like the relief valve, the monitor protects while allowing gas to continue to flow.

   b. **Containment.** Monitoring contains the gas. It prevents the gas from blowing into the atmosphere and keeps it inside the piping.

   c. **Alerting.** This is probably the main disadvantage of monitoring. Generally speaking, the only warning or notification is the rise in outlet pressure to monitor set-point. The problem with this is that it usually escapes notice.

3. **Automatic Shutoff**

   a. **Continuity of Service.** Automatic shutoff, of course, stops the flow of gas. It protects because it interrupts gas service by fully shutting off the gas.

   For a gas utility, where continuity of service is of serious importance, this characteristic of automatic shutoff is a big disadvantage.

A Typical Regulator and Relief Valve Installation

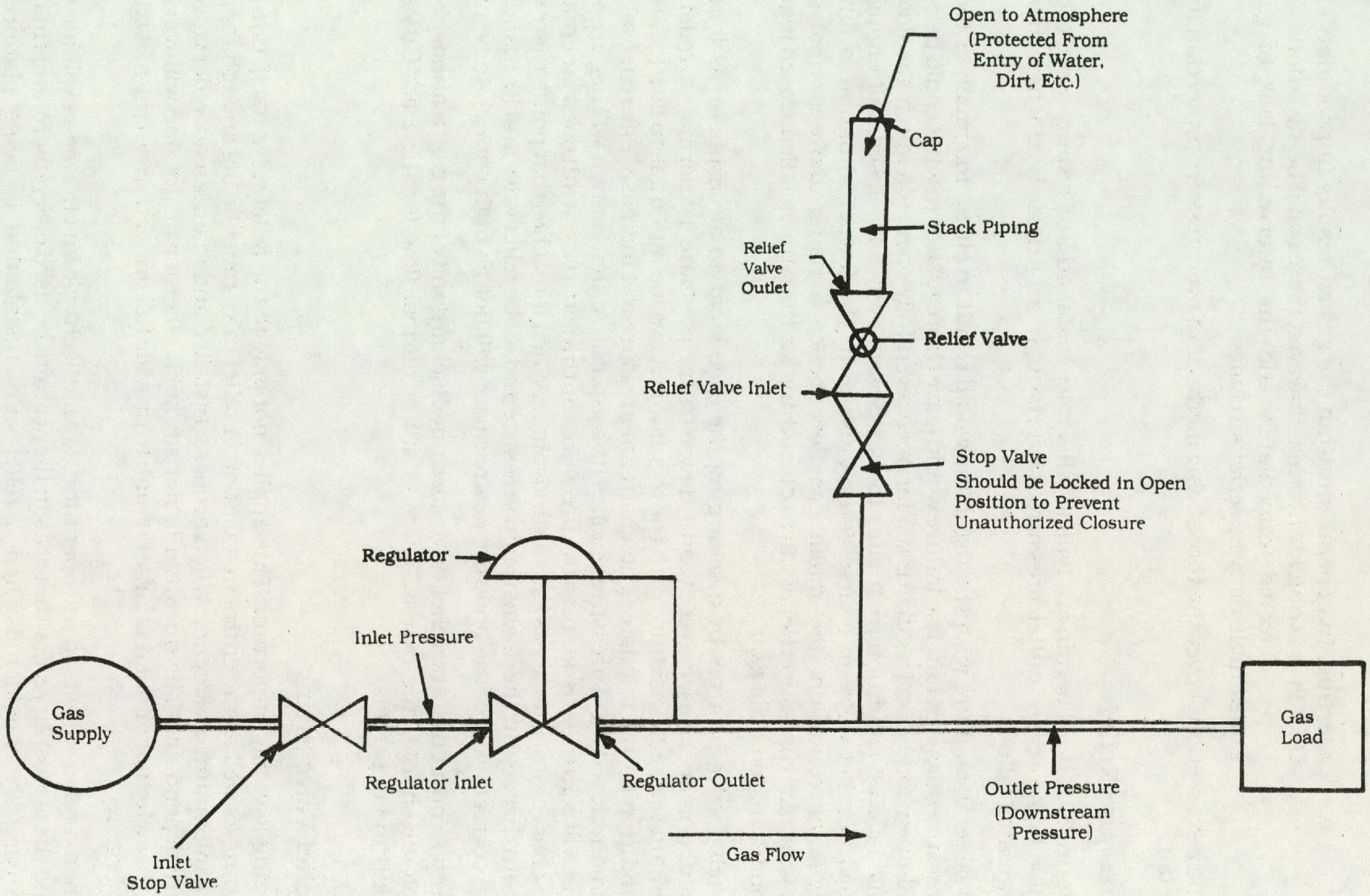


Figure 30A

b. **Containment.** Automatic shutoff contains the gas. Like monitoring, it does not allow gas to blow to atmosphere. It contains the gas within the piping.

c. **Alerting.** In general, shutting the gas off results in good notification. Usually it is quickly noticed. However, there could be situations when it is not detected immediately and the intervening lack of gas has undesirable or even serious results.

The next sections cover the three basic methods of overpressure protection in more detail.

F. Pressure Relief

Figure 30A, is a diagram of a typical relief valve installation. The purpose of the relief valve is to prevent outlet pressure from rising to an unsafe level when there is a regulator failure.

In general, a failure with the regulator would result in either too much or too little pressure downstream. The failure would leave the regulator in what could be called a fail-open condition (regulator too far open, even fully open, too much gas flow) or a failed-closed condition (regulator too far closed, even fully closed, not enough gas flow). A relief valve, of course, is only useful in the former situation, a fail-open regulator condition, too much gas flow; hence a rising above normal of the downstream pressure. Relief valves do nothing for the latter, a failed-closed regulator condition, too little gas.

A relief valve protects by discharging the excess gas to atmosphere. As long as a regulator operates correctly and downstream pressure is normal, a relief valve remains closed. If a failure with the regulator allows too much gas to flow (a fail-open condition for the regulator), downstream pressure will increase. The relief valve will remain closed until pressure reaches its set-point. At that point it will begin opening and will continue to do so, as the pressure continues to rise, until open far enough to discharge all of the excess gas to atmosphere. When it reaches that point, there will be no further rise in the downstream pressure and, if the relief valve and its installation are correctly sized, the pressure downstream will not be high enough to be unsafe.

Keep in mind that the relief valve does not discharge all of the gas to atmosphere. It only discharges the excess. There is still a normal flow for the load. Customers continue to get gas.

G. Relief Valve Sizing

Sizing is vitally important. This applies not only to the relief valve itself, but to the piping as well as the entire installation. A relief valve must be big enough to handle the maximum emergency. When properly installed and maintained, relief valves are very dependable. The question is not so much whether or not one will work, but rather whether or not it is large enough to provide full protection during a maximum emergency.

When a relief valve is in full operation, it can discharge an enormous volume of gas into the atmosphere. For that reason they cannot be used everywhere, and this must be carefully considered when a relief valve installation is being planned and engineered. The vital questions are these: What happens with the gas after it leaves the relief valve? Will it disperse harmlessly? Or, could it create another emergency? For the gas industry, this matter is addressed in 49 CFR 192.199(e).

Figure 30A shows a stop valve ahead of a relief valve. This stop valve is accepted in the gas industry because of maintenance and testing. However, there can be serious consequences if it happens to be closed during an emergency. Closure could be an innocent act or it could even be malicious. Nonetheless, certain cautions are essential. The stop valve must only be used by authorized personnel. It must be adequately protected against unauthorized closure. For the gas industry, 49 CFR 192.199(h) addresses this matter stating it should be locked in on open position.

H. Monitoring

This section will deal with the most widely used form of monitoring today, standby or passive monitoring. Figure 31 shows it in four basic arrangements, using regulators with control lines and with internal control. Note the following:

1. Either the upstream or the downstream regulator can be the monitor.
2. The downstream regulator can have either a control line or internal control.
3. The upstream regulator must have a control line.

Standby monitoring is sometimes confused with two-stage or double-cut regulation. The big difference, of course, is in the control line for the upstream regulator. In standby monitoring, the control line for the upstream regulator goes all the way downstream. It does not connect between the regulators as in two-stage regulation. To repeat, the control line for the upstream regulator in standby monitoring goes on beyond the downstream regulator to a point somewhere in the outlet piping. That is the reason the upstream regulator in standby monitoring must have a control line, whereas in two-stage regulation the upstream as well as the downstream regulator can have either a control line or internal control.

Two-stage regulation can be used as a form of monitoring provided the two following conditions are met:

1. The system downstream of the second stage regulator (including the regulator) must be safe at the set-point pressure of the first stage regulator.
2. The second stage regulator must be safely rated for an inlet pressure as high as the maximum inlet pressure to the first stage regulator.

Referring again to Figure 31, the set-point for the operating regulator is the normal outlet pressure, the pressure normally required for the load.

The set-point for the monitor is higher. Because it is higher, the monitor is further open than the operating regulator (usually the monitor is wide open) and allows the gas to flow normally.

If a fail-open failure in the operating regulator causes the outlet pressure to rise, it will do so until reaching the set-point of the monitor, whereupon the monitor will become the operating regulator to hold outlet pressure at its set-point.

Monitor set-point, of course, must not exceed the MAOP of the downstream piping system.

The difference between the set-points of the monitor and the operating regulator is not critical. The two should not be so close as to cause the monitor to interfere with

Standby Monitoring

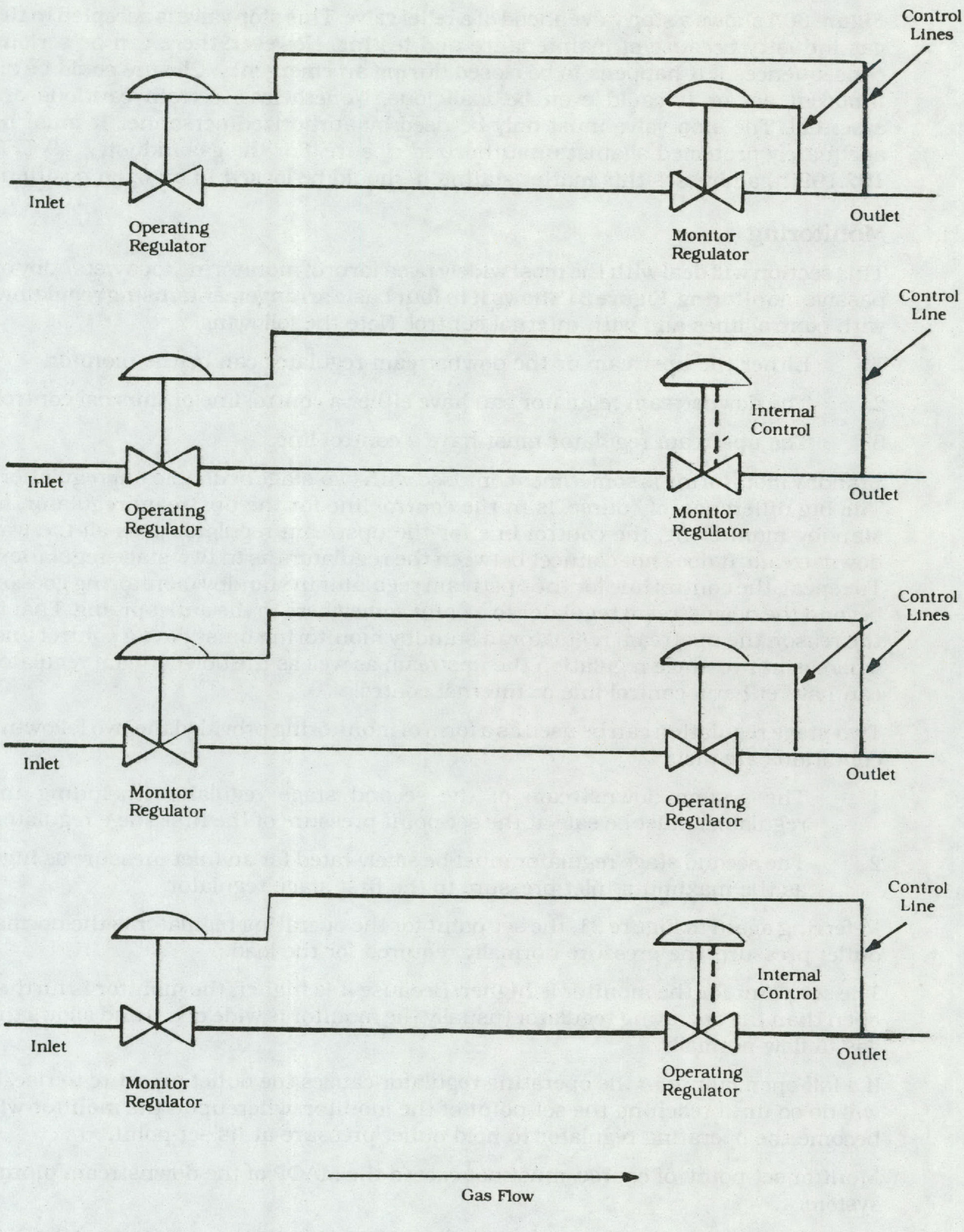


Figure 31

the other. Other than these, monitor set-point is largely determined by the requirements of the installation and applicable practices and standards.

I. Automatic Shutoff

In automatic shutoff a special valve is used to fully shut off the gas if pressure reaches a preset level.

During normal operation, the valve remains fully open and allows gas to flow freely. Pressure loss through the average valve of this kind is approximately that through a standard 90 degree ell.

If a regulator failure (fail-open failure) or something else causes outlet pressure to rise, the automatic shutoff valve closes when pressure reaches its set-point.

The normal outlet pressure is the regulator's set-point. The set-point of the automatic shutoff valve will, of course, be higher. How much higher must be decided when planning and engineering the installation, and it must not exceed the MAOP of the downstream piping, the maximum safe limit.

Automatic shutoff valves close automatically, but must be manually reset. This has the advantage of preventing an emergency from passing unnoticed. It also has an economic advantage because automatic reopening would greatly increase cost.

Shutting the gas off at times of emergency certainly is desirable. However, in the gas business, continuity of service is also important. That is probably the reason automatic shutoff has found only limited use in the gas industry. Pressure relief and monitoring are preferred because they offer full protection while allowing a safe flow of gas to continue.

Automatic shutoff valves are available with control line and with internal control. Figure 32, shows both in diagrams. Note the following regarding one versus the other:

1. **Internal Control** (Figure 32A):

   This offers a simpler installation because there is no control line. However, because of its internal control, it must be located downstream of the regulator. Therefore, upon closure everything upstream of the shutoff valve will be pressured to full inlet pressure.

   This means that if the regulator has internal control, its main diaphragm will be exposed to full inlet pressure. This could result in severe damage, even to the extent of the regulator bursting. The same applies to a regulator with a control line if the control line is connected (the sensing point) between the regulator and the automatic shutoff valve. In summary, if an automatic shutoff valve with internal control is used, everything between it and the regulator, including the regulator itself, must be carefully checked for exposure to full maximum inlet pressure.

   Moreover, if the outlet piping for the regulator is a larger size than the inlet piping, an internal control-type automatic shutoff valve will, accordingly, be a larger size than one with a control line.

2. **Control Line** (Figure 32B):

Because an automatic shutoff valve with a control line is located upstream of the regulator, the foregoing hazards from exposure to inlet pressure are eliminated. The entire regulator, as well as everything downstream, is isolated from exposure to inlet pressure.

Care should be used in installing the control line. It should be strong, protected, and routed to minimize any possibilities of breakage. If broken, the automatic shutoff valve becomes inoperative. If an emergency occurs, it will not close as it should.

Some automatic shutoff valves are available with a temperature option. They close not only from excess pressure, but also excess temperature. If properly located, they can be a help in case of fire. Automatic shutoff is also available for closure in case of underpressuring (a failed-closed regulator failure).

Relief valves, monitors, and automatic shutoff valves have all proven to be effective, dependable devices for protection against the hazard of excess pressure, or overpressuring. However, to be sure of this protection, all three must be correctly engineered, installed, and maintained. They must be used in conformance with manufacturers' ratings and recommendations. Whenever any doubts or questions arise, it is always a good idea to ask the manufacturer.

Automatic Shutoff Valve Installations

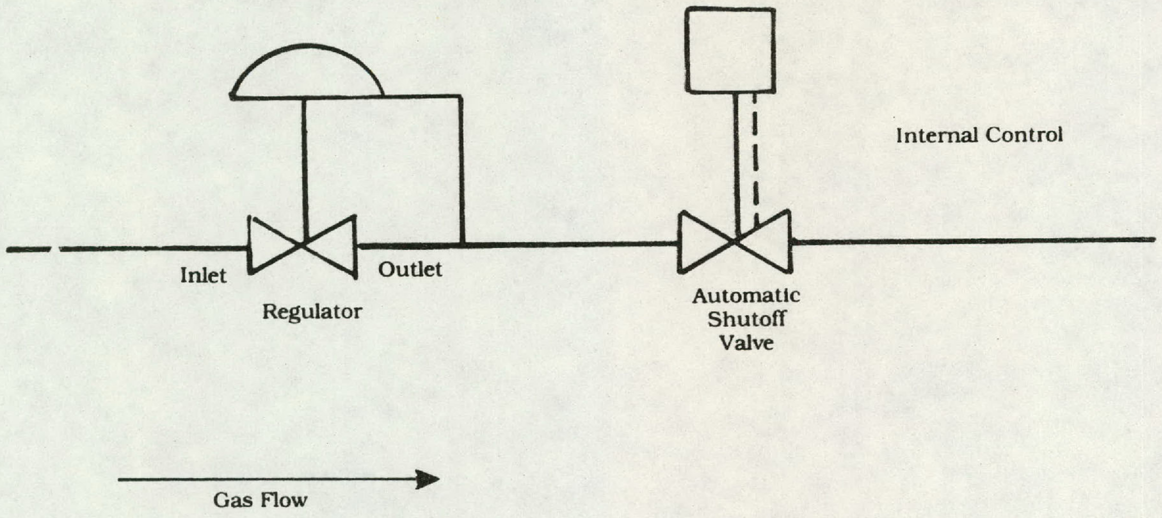


Figure 32A

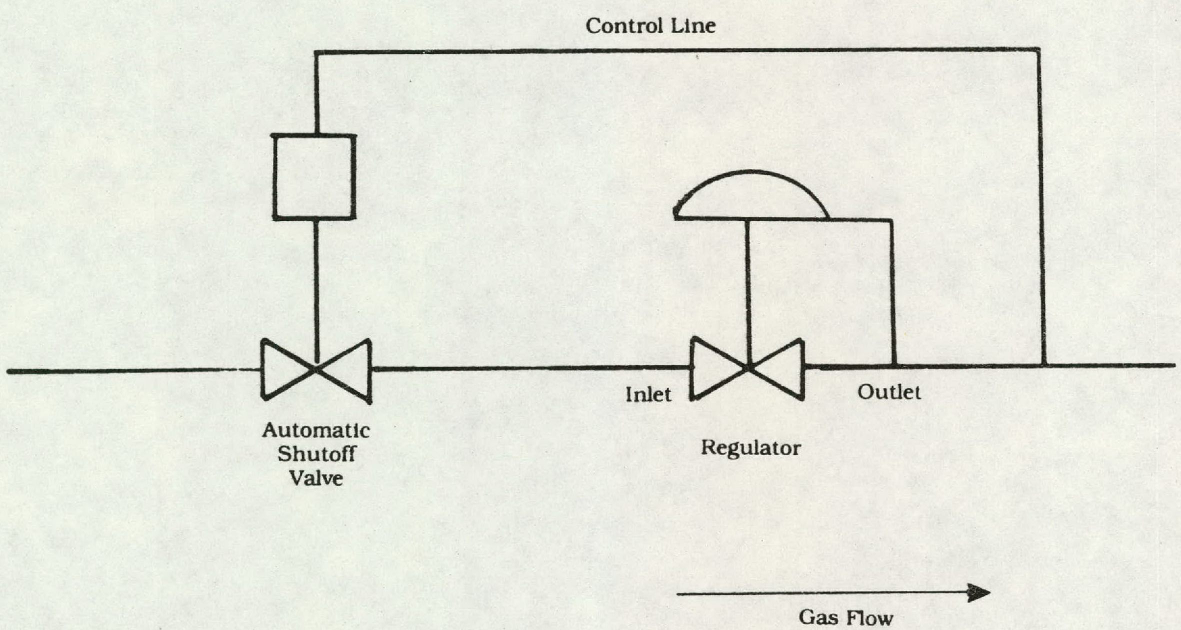


Figure 32B

NOTES

Appendix I

Requirements for Corrosion Control

Introduction

The following is a simplified breakdown of the minimum corrosion control requirements as they would normally apply to small natural and LP-gas operators. Those who want to read the complete text of the minimum corrosion control requirements can find them in Subpart I, 49 CFR Part 192.

A. Procedures and Qualifications

Operators must establish procedures to implement a corrosion control program for their piping system. These procedures should include the design, installation, operation, and maintenance of a cathodic protection system. These procedures must be carried out by, or be under the direction of, a person qualified by experience and training in pipeline corrosion control methods (192.453).

Techniques for Compliance

The following is a list of methods small operators can use to find qualified personnel to develop and carry out a corrosion control program.

1. There are many consultants and consulting firms specializing in the cathodic protection field. Many of these consultants advertise in gas trade journals. Section VII of this guideline lists a number of these journals with their addresses and telephone numbers.

2. Another source, especially for master meter operators, is an experienced corrosion engineer or experienced technicians working for the local gas utility company. These people may be able to implement the cathodic protection for you, or may be able to refer you to some local qualified corrosion engineers.

3. Municipal operators can contact their gas supplier. Its corrosion engineer or technician may be able to supply information as where to find a local qualified corrosion engineer(s).

4. In addition, the Railroad Commission of Texas suggests that small operators encourage the associations to which they may belong, such as state or local mobile home associations or state municipal associations, to gather and maintain records of consultants, consultant firms, or contractors who are qualified in your specific region.

5. The local chapter of the National Association of Corrosion Engineers (NACE) may be able to provide useful information.

6. Operators who are unsure whether a consultant is qualified to do corrosion work should ask the consultant to provide a list of other operators for whom he has done work. These operators can be contacted to see if the consultant's work was satisfactory.

B. Minimum Corrosion Control Requirements for Pipelines Installed After July 31, 1971

1. All buried metallic pipe installed after July 31, 1971, must be properly coated

and have a cathodic protection system designed to protect the pipe in its entirety (192.455(a)).

2. Rule for newly constructed metallic pipelines. Each coated pipeline installed must have a cathodic protection system installed and placed in operation in its entirety within one year after completion of construction of the pipeline. Normally, cathodic protection is installed at the time of construction.

3. If the operator can demonstrate by tests, investigation, or experience that a corrosive environment does not exist, he is not required to coat and cathodically protect the pipeline. However, no later than six months after installation, the operator must make tests to prove that no corrosion control measures were necessary. If tests fail, it must be cathodically protected (192.455(b)).

   NOTE: The RRC recommends that all small operators coat and cathodically protect all metallic pipe. This is because it is extremely difficult and costly to prove that a noncorrosive environment exists.

4. Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines if the fitting's alloy provides corrosion control and if corrosion pitting of the fitting will not cause leakage, (192.455(e)).

C. Minimum Corrosion Control Requirements for Gas Distribution Pipelines Installed Before August 1, 1971

1. For master meter and municipal gas distribution systems, the minimum regulations require that bare or coated distribution pipelines, and regulating and measuring stations be cathodically protected in areas of active corrosion (192.457).

2. The operator must determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, or by leak detection surveys.

3. Active corrosion by accepted definition means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety (192.457(c)).

D. Municipal operators operating transmission supply lines installed before July 31, 1971, corrosion control requirements are as follows:

1. Existing effectively coated transmission lines must be cathodically protected in their entirety.

2. Existing bare transmission lines must be cathodically protected in areas where active corrosion is found.

E. Coating Requirements

All metallic pipe installed below ground as a new piping system or as a replacement system should be coated in its entirety (192.461) (Form 101.1, Appendix E).

A discussion of some different kinds of coatings and handling practices are included in Appendix J. Generally, small operators should consider purchasing pipe already coated from a supplier, rather than attempting to coat pipe in the field.

F. Examination of Exposed Pipe

When any portion of a buried pipe is exposed, operators are required to examine that portion for evidence of corrosion on bare pipe or for deterioration of the coating on coated pipe. A record of this examination must be maintained. If the coating has deteriorated or the bare pipe has evidence of corrosion, remedial action must be taken (192.459) (Form 101.1, Appendix E).

G. Criteria for Cathodic Protection

Operators must meet one of five criteria listed in Appendix D, 49 CFR 192, in order to meet the minimum requirements for cathodic protection.

NOTE: The criteria that most small operators will choose to meet will be a (cathodic) voltage of at least -0.85 volts, with reference to a saturated copper-copper sulfate half cell (Form 111.1, Appendix E).

Illustrations, some basic terms, instruments, and practical considerations regarding cathodic protection are discussed in Appendix J.

H. Monitoring

A piping system which is under cathodic protection must be monitored systematically (192.465).

1. A monitoring system must be maintained. Test for effectiveness of cathodic protection must be done at least once each calendar year, at intervals not exceeding 15 months. Records of this monitoring must be maintained (Form 111.1, Appendix E).
2. Short, separately protected service lines or short protected mains may be surveyed on a sampling basis. At least 10 percent of short sections (100 ft. or less in length) and services must be checked each year so that all short sections in the system are tested in a 10 year period.

   Examples of short, separately protected pipe in a small gas system would be:

   a. Steel service lines connected to but electrically isolated from cast iron mains.

   b. Plastic service lines with steel service risers which have cathodic protection provided from an anode attached to riser.

      If you only have a small number of isolated protected sections of pipeline in the system, include these sections in your annual survey.
3. If you use rectifiers to provide cathodic protection, each rectifier must be inspected six times each calendar year, but with intervals not exceeding two and one-half months, to ensure that it is operating. Records must be maintained. (Form 112.1, Appendix E)
4. Operators must take prompt action to correct any deficiencies indicated by the monitoring.

I. Electrical Isolation

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a single unit). (If impossible to insulate casing pipe, other measures must be taken to minimize corrosion inside the casing, such as filling the space between the casing and pipe with a high resistance material (192.467).

J. Test Points

Each pipeline under cathodic protection must have sufficient test points for electrical measurement to determine the adequacy of cathodic protection (192.469, 192.471). Test points over or near an anode shall not by themselves be considered representative readings. Test points should be maintained on a cathodic protection system map.

K. Internal Corrosion Inspection

Whenever a section of pipe is removed from the system, the internal surface must be inspected for evidence of corrosion. Remedial steps must be taken if internal corrosion is found. Be sure to keep records of this inspection (192.475) (Form 101.1, Appendix E).

L. Atmospheric Corrosion

Portions of newly installed aboveground pipelines must be cleaned and coated or jacketed with a material suitable for the prevention of atmospheric corrosion (192.479). Aboveground pipe, including meters, regulators, and measuring stations, must be inspected for atmospheric corrosion once each calendar year, but with intervals not exceeding three years. Remedial action must be taken if atmospheric corrosion is found (192.481) (Form 110.2, Appendix E).

M. Remedial Measures

All steel pipe used to replace an existing pipe must be coated and cathodically protected. Each segment of pipe that must be repaired because of a corrosion leak must be cathodically protected (192.483).

N. General Graphitization

Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result must be replaced. Localized graphitization found to a degree where leakage may occur must be repaired (192.489).

O. Records

Operators must maintain records or maps of their cathodic protection system. Records of all tests, surveys, or inspections required by the above minimum requirements must be maintained and retained for the life of the segment. See Appendix E for sample of records (192.491).

Appendix J

Some Principles and Practices of Cathodic Protection

Overview

The intent of this appendix is to give operators who have little or no experience in the cathodic protection field some of the general principles and practices of cathodic protection. Common causes of corrosion, pipe coatings, and criteria are typical topics discussed. A check list containing steps that an operator of a small system may use in determining a system's needs for cathodic protection is also included. Basic definitions and illustrations are used to clarify the subject. However, this Appendix does not go into great depth. Therefore, an operator will not be qualified to design and implement a cathodic protection program for a piping system just by reading this Appendix.

A. Basic Terms

1. *Corrosion* is the deterioration of a metal pipe. The corrosion is caused by a reaction that takes place between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Underground corrosion can be retarded with cathodic protection (See Figure 32).

2. *Cathodic protection* is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed on the pipe by means of either a sacrificial anode or a rectifier.

3. *Anode* (sacrificial) is an assembly consisting of a bag, usually containing a magnesium ingot and other chemicals, that is connected to an underground metal piping system. It serves essentially as a battery which impresses a direct current on the piping system to retard corrosion (See Figure 33).

4. *Sacrificial protection* means the reduction or prevention of corrosion of a metal in an electrolyte by galvanically coupling the metal to a more anodic metal (See Figure 34).

5. *Rectifier* is an electrical device which changes alternating current (A.C.) into direct current (D.C.). This current is than impressed on an underground metallic piping system to protect it against corrosion (See Figure 35).

6. *Potential* means the difference in voltage between two points of measurement (See Figure 36).

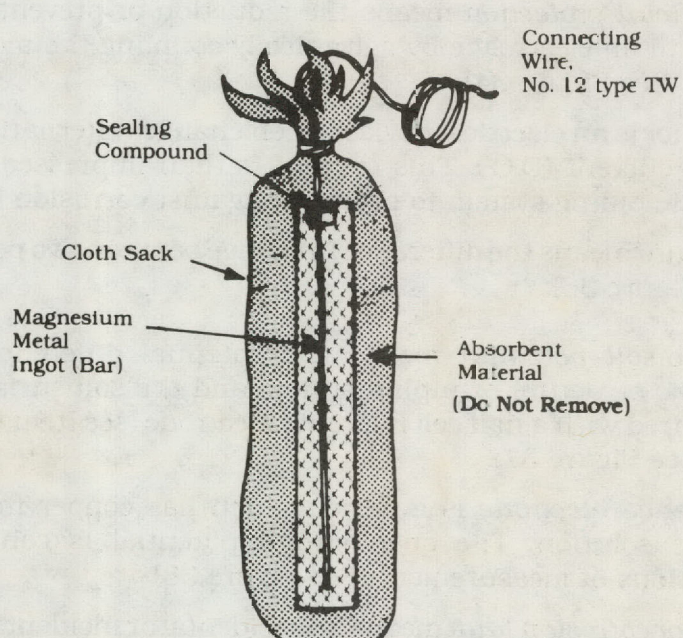
7. *Pipe-to-soil potential* means the potential difference between a buried metallic structure or piping system and the soil surface. The difference is measured with a half cell reference electrode (see Item 8) in contact with the soil (See Figure 37).

8. *Reference electrode* is a device which has copper immersed in a copper sulfate solution. The open circuit potential is constant under similar conditions of measurement (See Figure 38).

9. *Short or corrosion fault* means an accidental or incidental contact between: (a) a cathodically protected section of a piping system; and (b) other metal structures (water pipes, buried tanks, or unprotected section of a gas piping system) (See Figure 39).

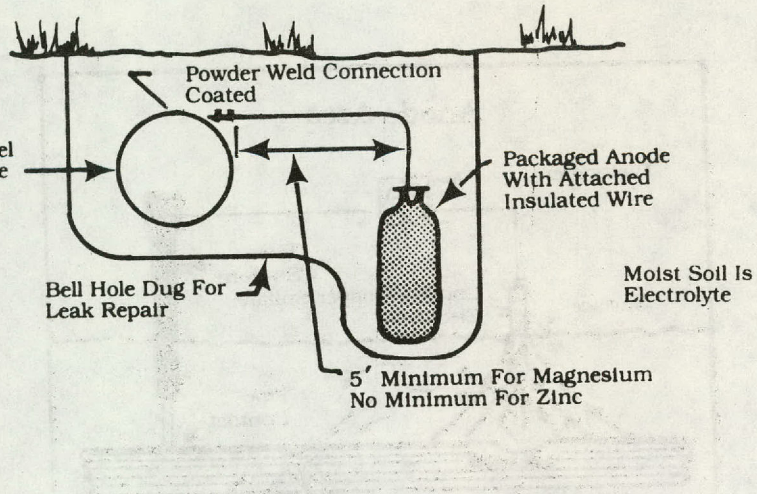
Example of Atmospheric Corrosion

Figure 32



Typical Pre-Packaged Magnesium Anode

Figure 33



Single Packaged Anode Installation

Figure 34

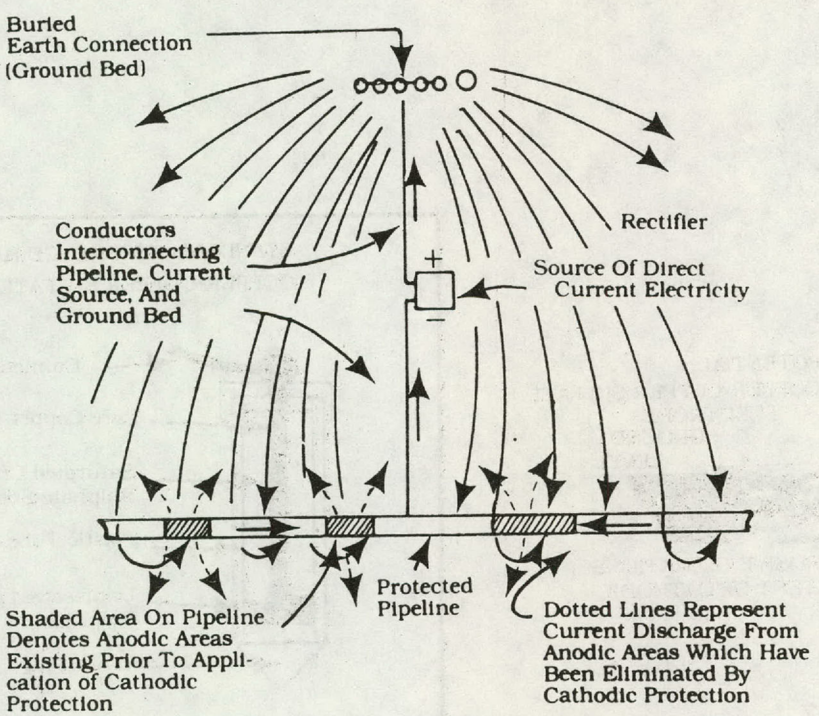
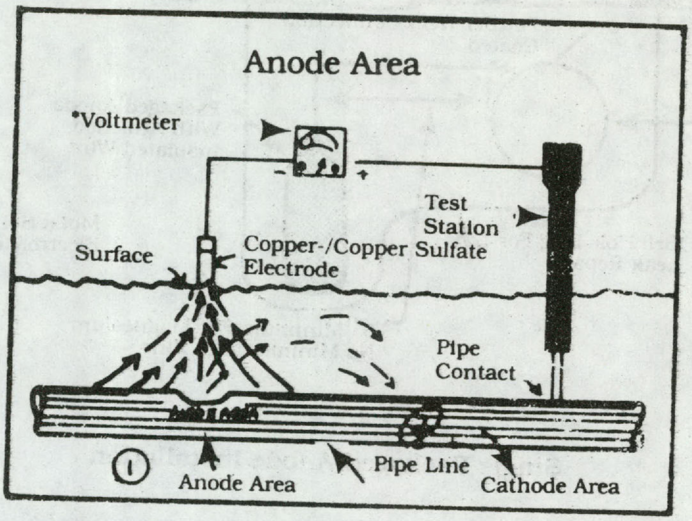


Figure 35



The voltage potential in this case is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2).

Figure 36

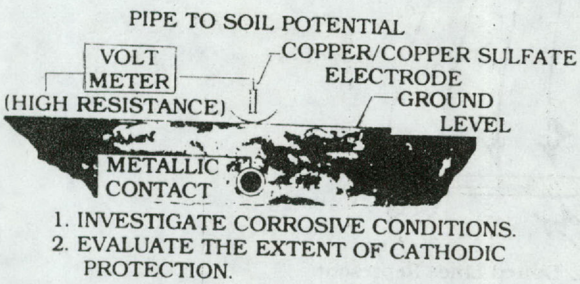


Figure 37

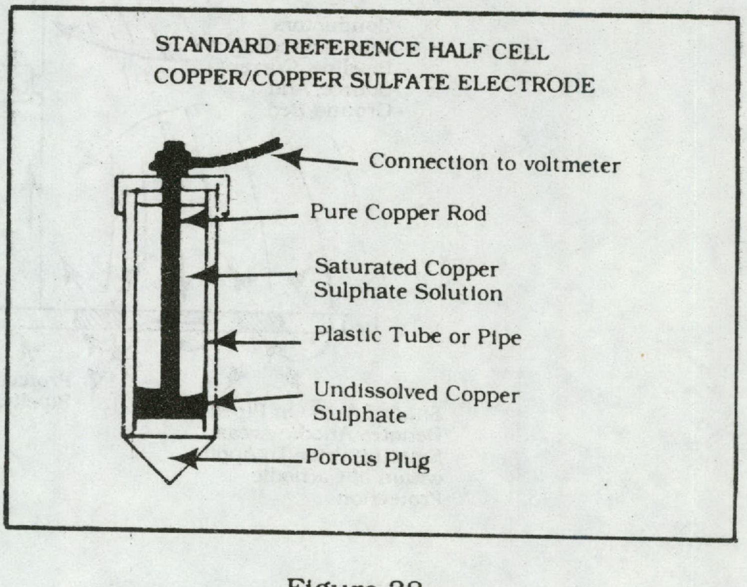


Figure 38

10. *Stray current* is current flowing through paths other than the intended circuit (See Figure 40).

11. *Stray current corrosion* is the metal destruction or deterioration caused primarily by stray D.C. current in the soil around a pipeline.

12. *Galvanic series* is a list of metals and alloys arranged according to their relative potentials in a given environment.

13. *Galvanic corrosion* occurs when any two of the metals in Table 4 are connected in an electrolyte (soil). This galvanic corrosion is caused by the difference in potentials of the two metals (See Figure 41).

B. Fundamental Corrosion Control Theory

In order for corrosion to occur, there must be four elements: electrolyte, anode, cathode, and a return circuit. A metal will corrode at the point where current leaves the structure (See Figure 42).

1. A corrosion cell may be summed up as follows:

   a. Current flows through the electrolyte from the anode to the cathode. it returns to the anode through the return circuit.

   b. Corrosion occurs wherever current leaves the metal (pipe, fitting, etc.) and enters the soil (electrolyte). The point where current leaves is called the anode. Corrosion, therefore, occurs in the anodic area.

   c. Current is picked up at the cathode. No corrosion occurs here. The cathode is protected against corrosion. Polarization (hydrogen film buildup) occurs at the cathode. When the film of hydrogen remains on the cathode surface, it acts as an insulator and reduces the corrosion current flow.

   d. The flow of current is caused by a potential (voltage) difference between the anode and the cathode.

C. Types of Cathodic Protection

There are two basic methods of cathodic protection: the galvanic anode system and the impressed current system.

Galvanic anodes are commonly used to provide cathodic protection on gas distribution systems. Impressed current systems are normally used for transmission lines. However, if properly designed, impressed current can be used on distribution systems (See Figure 43).

Any current, whether galvanic or stray, that leaves the pipeline causes corrosion. In general, corrosion control is obtained as follows:

1. **Galvanic Anodes System.** Anodes are sized to meet current requirements of the resistivity of the environment (soil). Anodes are made of materials such as magnesium, zinc, or aluminum. They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe (See Figures 34, 43, and 44).

2. **Impressed Current System.** This system is normally used along transmission pipelines where there is less likelihood of interference with

Typical Meter Installation Accidental Contacts
(Meter Insulator Shorted Out by House Piping, etc.)

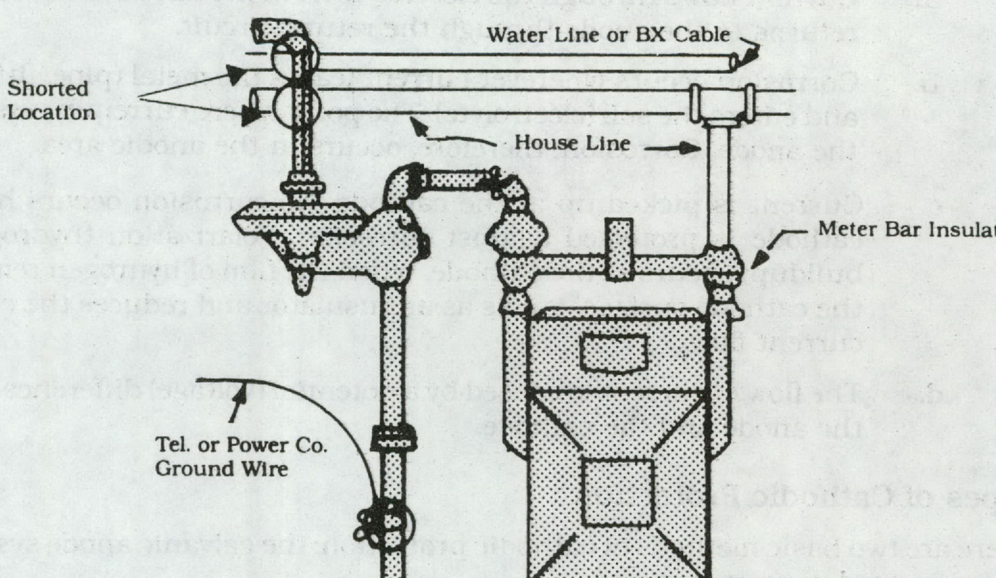
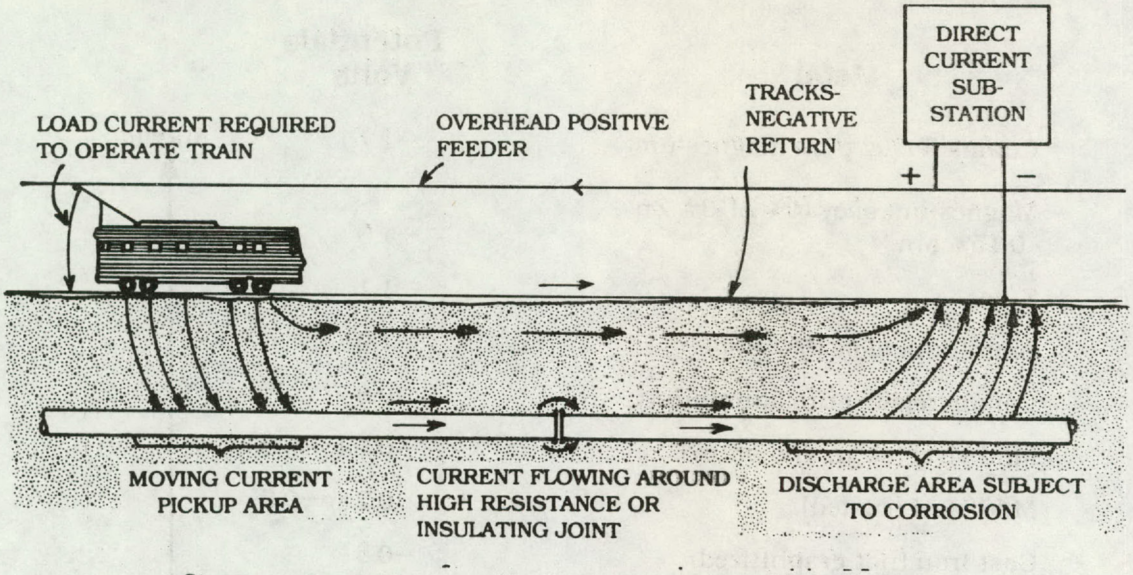
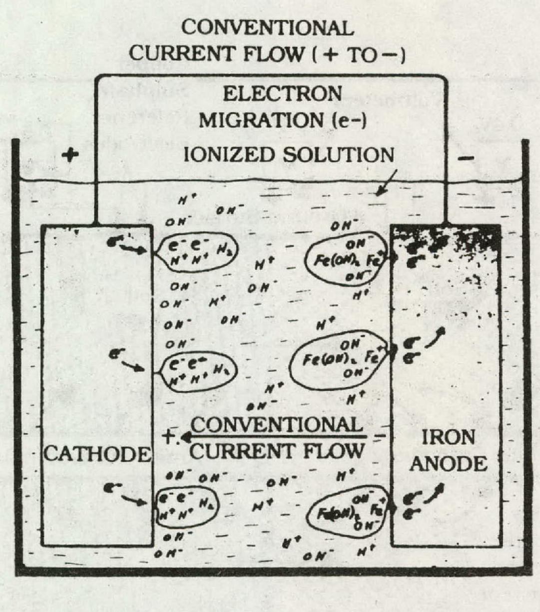


Figure 39



--Stray current corrosion caused by direct current powered transit system

Figure 40

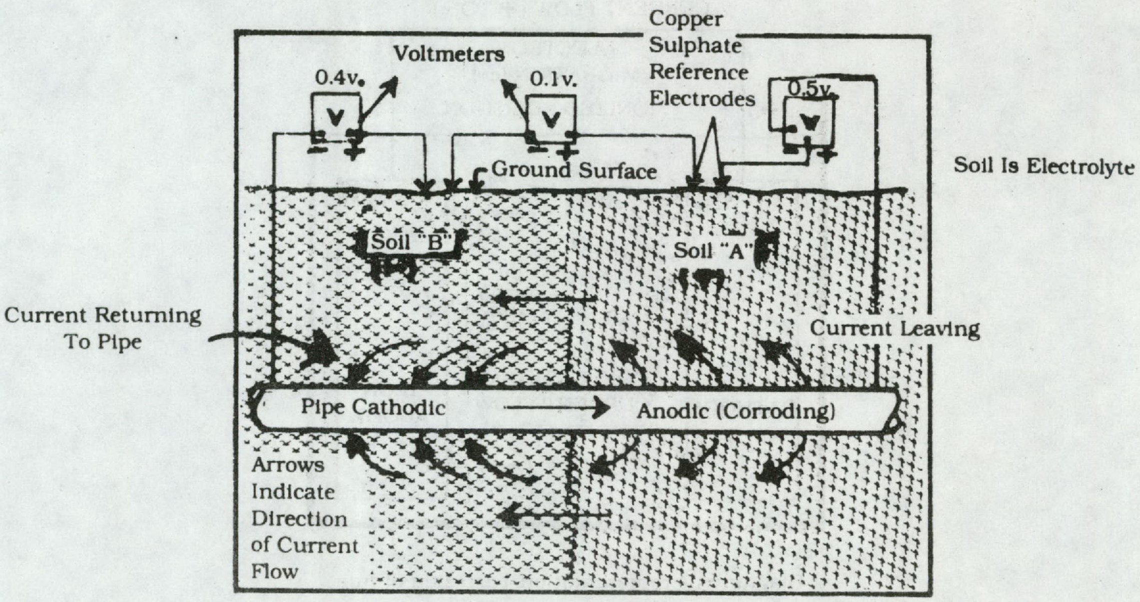


--Diagramatic representation, corrosion of iron

Figure 41

Table 4

Metal	Potentials Volts	
Commercially pure magnesium	−1.75	Anodic
Magnesium alloy (6% Al, 3% Zn 0.15% Mn	−1.6	
Zinc	−1.1	
Aluminum alloy (5% zinc)	−1.05	
Commercially pure aluminum	−0.8	
Mild steel (clean and shiny)	−0.5 to −0.8	
Mild steel (rusted)	−0.2 to −0.5	
Cast iron (not graphitized)	−0.5	
Lead	−0.5	
Mild steel in concrete	−0.2	
Copper, brass, bronze	−0.2	
High silicon cast iron	−0.2	
Mill scale on steel	−0.2	
Carbon, graphite, coke	+0.3	Cathodic



Corrosion from dissimilar soils

Figure 42

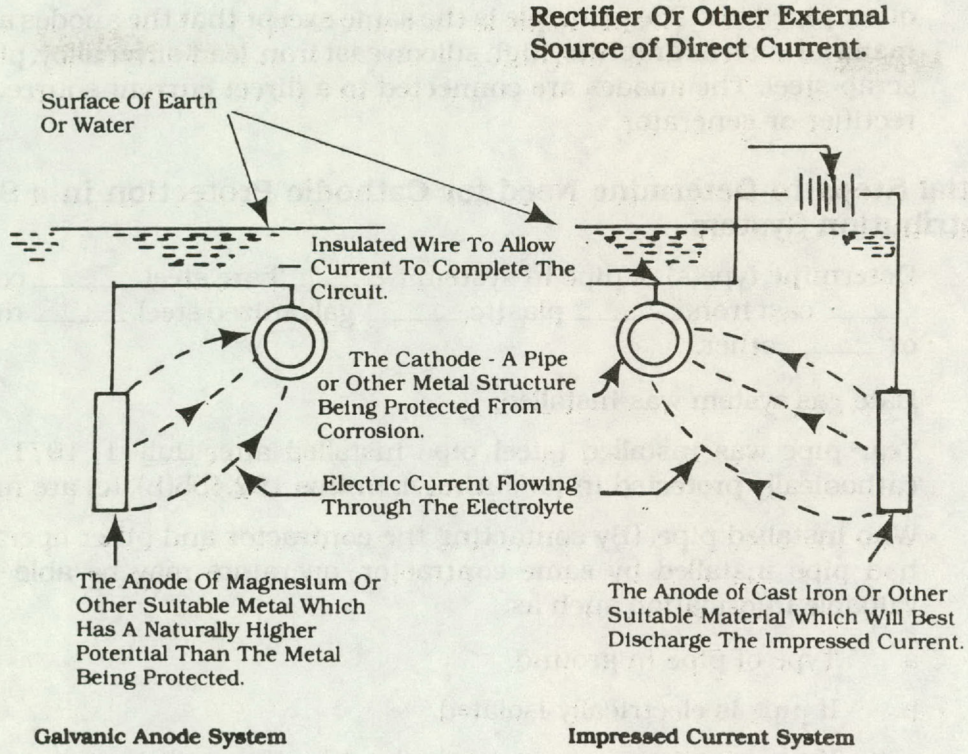


Figure 43

Typical procedure for installing a magnesium anode conductor (wire) to gas pipe.

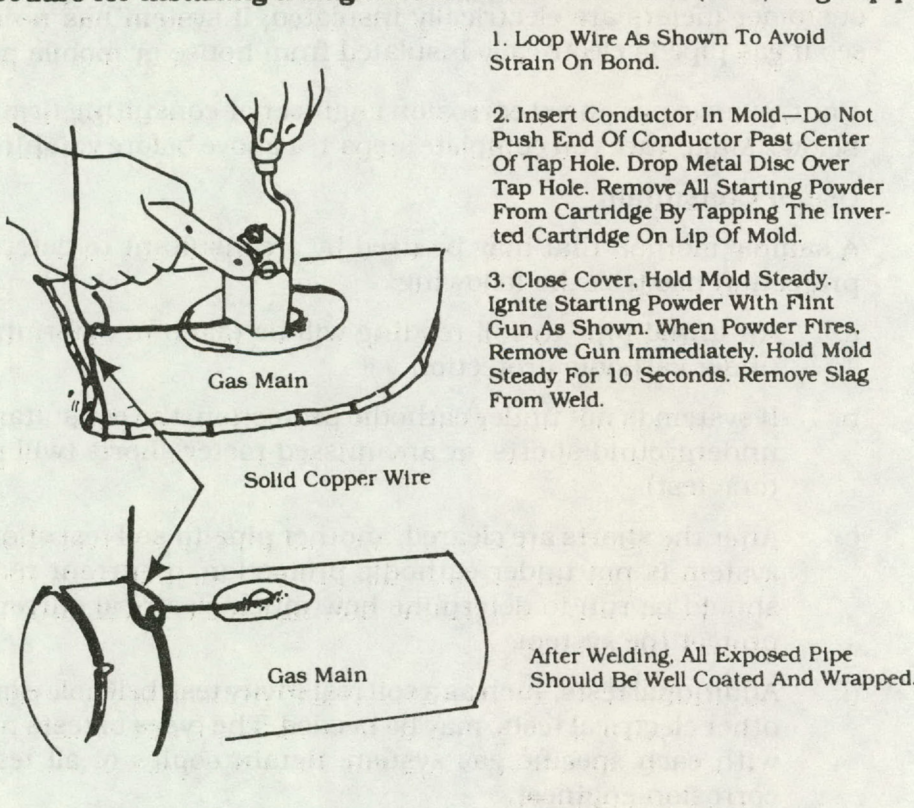


Figure 44

other pipelines. The principle is the same except that the anodes are made of material such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel. The anodes are connected to a direct current source, such as a rectifier or generator.

D. Initial Steps to Determine Need for Cathodic Protection in a Small Gas Distribution System

1. Determine type(s) of pipe in system: ______ bare steel, ______ coated steel, ______ cast iron, ______ plastic, ______ galvanized steel, ______ ductile iron, or ______ other.

2. **Date gas system was installed:**

   Year pipe was installed (steel pipe installed after July 1, 1971, **must** be cathodically protected in its entirety), unless 192.455(b), (c) are met.

   Who installed pipe. (By contacting the contractor and other operators who had pipe installed by same contractor, operators may be able to obtain valuable information such as:

   a. Type of pipe in ground.

   b. If pipe is electrically isolated.

   c. If gas pipe is in common trench with other utilities, etc.

3. Pipe location (map/drawing). Locate old construction drawings or current system maps. If no drawings are available, a metallic pipe locator may be used.

4. Before the corrosion engineer arrives, it is a good idea to make sure that customer meters are electrically insulated. If system has no meter, check to see if gas pipe is electrically insulated from house or mobile home pipe.

5. Contact an experienced corrosion engineer or consulting firm (See Section 6 below). Make sure you complete steps 1-4 above before you hire a consultant.

6. **Use of Consultant**

   A sample method that may be used by a consultant to determine cathodic protection needs is the following:

   a. An initial pipe-to-soil reading will be taken to determine if system is under cathodic protection.

   b. If system is not under cathodic protection, the consultant should clear underground shorts, or any missed meter shorts (will probably use a tone test).

   c. After the shorts are cleared, another pipe-to-soil test should be taken. If system is not under cathodic protection, a current requirement test should be run to determine how much electrical current is needed to protect the system.

   d. Additional tests, such as a soil resistivity test, bell hole examination, and other electrical tests, may be needed. The types of tests needed will vary with each specific gas system. Retain copies of all tests run by the corrosion engineer.

7. **Cathodic Protection Design**

Based on the results of testing, the experienced corrosion engineer or gas consultant will design a cathodic protection system that best suits your piping system.

E. Criteria for Cathodic Protection

There are five criteria listed in 49 CFR 192, Appendix D, that qualify as cathodic protection. The operators can meet the requirements of any of the five to be in compliance with the minimum safety standards. Most systems will be designed to criteria 1.

1. With the protective current applied, a voltage of at least -0.85 volts measured between the pipeline and a saturated copper-copper sulfate half cell. This measurement is called the pipe-to-soil potential reading.
2. With the protective current applied, a negative shift of at least 300 millivolts. Does not apply to pipelines consisting of metals with different anodic potentials.
3. A negative shift of the polarization voltage of at least 100 millivolts. The base voltage measured is that observed just after the protective current is interrupted.
4. A negative voltage established by testing to determine the beginning of the Tafel segment of an E-log-I curve.
5. Measurement of net current flowing onto the pipeline at predetermined corrosive areas.

F. Coatings

There are many different kinds of coatings on the market. The better the coating the less amount of current needed to cathodically protect the pipe.

1. **Mill Coated Pipe**

When purchasing steel pipe for underground gas services, operators should purchase mill coated pipe. Some examples of mill coatings are:

a. Extruded polyethylene or polypropylene plastic coatings

b. Coal tar coatings

c. Enamels

d. Mastics

e. Epoxy

A qualified corrosion person can help you select the best coating for your system. The local gas utility may be able to give master meter operators the name and location of nearby suppliers of mill coated gas pipe. Remember you purchase steel pipe to verify that the pipe was manufactured according to one of the specifications listed in Section IV of this guidebook. This can be by bill of lading and by the markings on mill coated pipe.

2. **Patching**

Tape material is a good choice for repair of mill coated pipe. Tape material is a good coating for both welded and mechanical joints made in the field. One advantage is that these tapes may be applied cold. Some tapes in use today are:

a. PE and PVC tapes with self-adhesive backing applied to a primed pipe surface.

b. Plastic films with butyle rubber backing applied to a primed surface.

c. Plastic films with various bituminous backings.

NOTE: Consult your pipe supplier before purchasing tapes. Tapes must be compatible with the mill coated pipe.

3. **Coating Application Procedures**

When repairing and installing metal pipe, be sure to coat bare pipes, fittings, etc. It is absolutely essential that the instructions (supplied by the manufacturer of the coating) are followed **precisely**. Time and money is wasted if they are **not** followed.

Some general guidelines for installing pipe coatings:

a. Properly clean pipe surface. (Remove soil, oil, grease, and any moisture.)

b. Use careful priming techniques (avoid moisture and follow manufacturer's recommendations).

c. Proper application of coating materials (avoid moisture and follow manufacturer's recommendations). **Make sure soil or other foreign material does not get under coating during installation.**

d. Backfilling. Only backfilling that is free of objects capable of damaging the coating should be allowed to strike the coated pipe directly. **Severe coating damage can be caused by careless backfilling operations when rocks and debris strike and break the coating.**

Appendix K

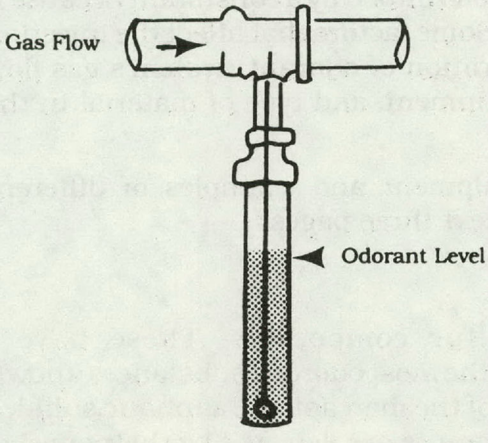
Odorization Equipment

Introduction

This section would normally not apply to master meter operators if they receive gas already odorized. Sections A through D apply to natural gas operators who odorize their own gas. Section E applies to ALL LP-GAS operators.

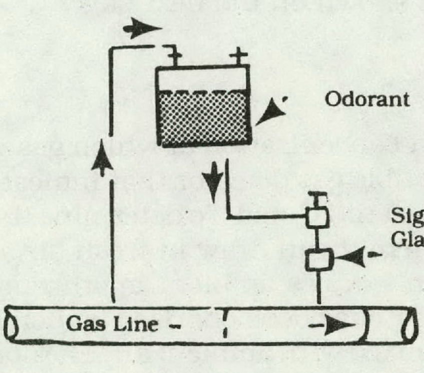
A. General

This is a brief discussion about odorization equipment used by operators of small natural gas systems.



—Equipment which odorizes the gas by having natural gas flow across a wick saturated with odorant. Generally used for individual lines such as farm taps.

Single-Unit wick odorizer



—Equipment for introducing odorant from a storage tank directly into a gas stream through gravity flow. The odorant may be regulated by orifice float valves, or rotameters.

Drip-type odorizer

NOTE: Odorization equipment may need seasonal adjustments. Valves which regulate the amount of gas diverted into an odorizer need to be adjusted between seasons of high and low flow of gas (winter vs. summer). Based on the equipment manufacturer's recommendation, your consultant should develop these operational instructions for your specific system. These instructions should be included in your O&M plan.

B. Equipment Selection Considerations

1. Determine if natural gas purchased from the supplier is odorized.
2. Determine if the purchased gas meets the minimum odorization level so that when gas is present in air at a concentration of as much as one percent by volume, a person with a normal sense of smell can readily detect it.
3. Sizing of odorization equipment should be based on the system's material make up, amount of gas used, and seasonal flows.
4. The injection rate of odorant should be determined by a consultant because it will vary for each individual gas system. Some factors that affect the injection rate are: type of odorant used, concentration of odorant, system's gas flow characteristics, type of odorization equipment, and type of material in the system.

   NOTE: A list of RRC approved equipment and examples of different odorizers are shown on the next three pages.

C. Kinds of Odorants

Odorants commonly used today are sulfur compounds. These have a characteristically pungent odor and are among the most odorous substances known. Generally, odorants are a blend of one or more of the mercaptans, aliphatic sulfides, or cyclic carbon sulphur ring compounds. Odorants are detected by their smell or their chemical composition. The sense of smell is very discerning and can detect mercaptans at a concentration of only one ppb, which is currently beyond the capabilities of most instruments. Odorants in the gas stream have a sulfur content that can be measured by gas analysis, which may then be used to determine if there is sufficient odorant. The most important detectors are the odorometer, the titrator, and the odotron. Of these instruments, the most commonly used is the odorometer.

NOTE: A list of RRC approved odorants is shown on the next page.

Discussion of Odorometer

The odorometer is used to determine the lowest concentration at which gas can be detected by odor. Actually, the unit is a combustible gas detector that indicates the percent of gas by volume in a sample which is also sniff tested. To determine the odor threshold level, the unit is used in an area where it can draw in fresh air and be connected to a gas source. A blower in the unit draws ambient air through the analyzer and out the exhaust chamber. Gas which has been odorized is then slowly admitted to the intake of the blower where it is mixed with ambient air. The operator continually sniffs the exhaust gas-air mixture. When an odor is first detected, he then measures the concentration of gas in the mixture by aspirating a sample through the analyzer.

Commercially Available Odorization Equipment Approved by the Railroad Commission For Use in the State of Texas

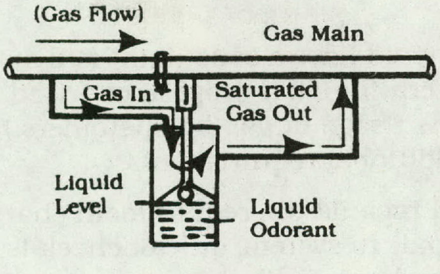
Brand Name	*Model Number*	*Type*
Arnold Energy Systems, Inc.	Advanced/Design	Positive Displacement Pump
Hanby Co.	Unit No. 644	Wick
King Tool	Standard 1-B	Absorption Bypass
King Tool	Standard 2-B	Absorption Bypass
King Tool	Standard 3-B	Absorption Bypass
King Tool	Standard 4-B	Absorption Bypass
King Tool	Standard 5-B	Absorption Bypass
King Tool	Standard 6-B	Absorption Bypass
King Tool	1-W	Wick
King Tool	3-W	Wick
King Tool	4-W	Wick
King Tool	5-W	Wick
Morgan Products, Inc.	50 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	100 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	200 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	230 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	250 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	3,000 DS	Positive Displacement-Chemical Injection Pump
Morgan Products, Inc.	4,000 DS	Positive Displacement-Chemical Injection Pump
Peerless	42-203	Wick
Peerless	MP-200	Meter Drive-Liquid Injection
Peerless	MP-550	Meter Drive-Liquid Injection
Peerless	MP-1000	Meter Drive-Liquid Injection
Peerless	42-100	Bypass
Peerless	42-200	Wick
Peerless	MP Special	Positive Displacement Pump-Liquid Injection
Peerless	42-204	Wick
Peerless	42-208	Wick
Peerless	42-109.4	Bypass
Peerless	42-118.5	Bypass
Peerless	42-120	Bypass
Peerless	42-154	Bypass
Peerless	42-157	Bypass
Process Systems Inc.	POIS 100	Liquid Injection
Process Systems Inc.	POIS 300	Liquid Injection
Welker Engineering Co.	MP-2	Positive Displacement Chemical Pump
Williams	CD-3000	Drip
Williams	XSDSP-Series	Positive Displacement Pump-Liquid Injection
Williams	B-100-Series	Positive Displacement Bourdon Pump-Liquid Injection
Williams	B	Positive Displacement Pump-Liquid Injection

This list will be revised as manufacturers request and are granted approval of equipment submitted in accordance with Gas Utilities Substantive Rule 16 TAC §7.71(d)(1).

This list contains only commercially available equipment. RRC approval on all other equipment will be recognized by the RRC/GUD Docket No. of the order issuing that approval under 16 TAC §7.71(d)(2).

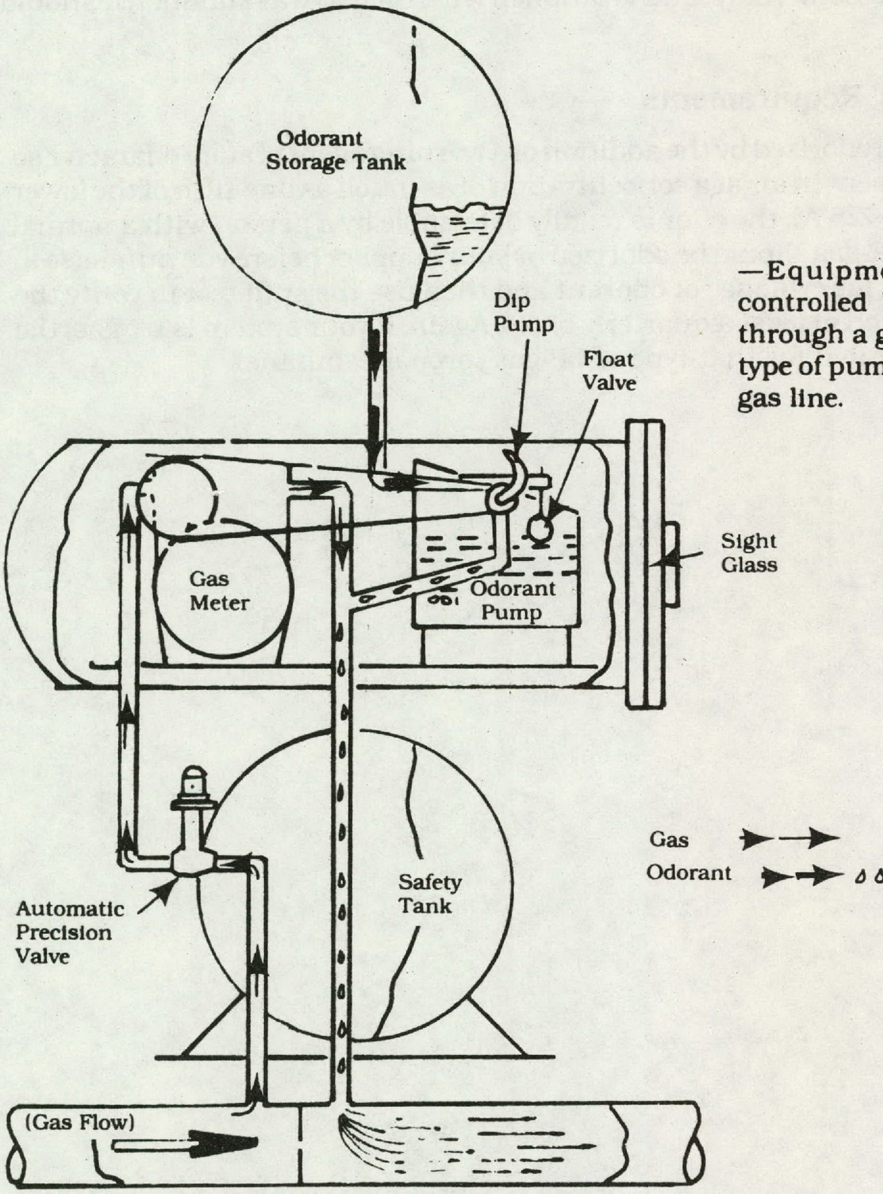
Malodorants Approved by the Railroad Commission For Use in the State of Texas

Malodorant Name	*Manufacturer*	*Concentrate (C) or Dilute (D)*	*Weight per Gal. at 60° F.*
Captan	Natural Gas Odorizing	C	6.88 lb.
B. P. Captan	Natural Gas Odorizing	C	6.75 lb.
L. P. Captan	Natural Gas Odorizing	C	7.00 lb.
R. P. Captan	Natural Gas Odorizing	C	6.80 lb.
R. P. Captan (V)	Natural Gas Odorizing	C	6.76 lb.
T. B. Captan	Natural Gas Odorizing	C	6.82 lb.
Captan 99	Natural Gas Odorizing	C	6.88 lb.
D. L. Captan	Natural Gas Odorizing	D	6.00 lb.
C. L. Captan	Natural Gas Odorizing	D	6.00 lb.
C. S. Captan	Natural Gas Odorizing	C	8.32 lb.
C.S. - B.P. Captan No. 11	Natural Gas Odorizing	C	7.54 lb.
Captan 85	Natural Gas Odorizing	C	6.95 lb.
Captan 90	Natural Gas Odorizing	C	6.90 lb.
Gasniff	Natural Gas Odorizing	C	6.92 lb.
25% B. P. Captan (M. C. Captan)	Natural Gas Odorizing	D	5.80 lb.
Spotleak 1001	Pennwalt Corporation	C	6.80 lb.
Spotleak 1003	Pennwalt Corporation	C	6.80 lb.
Spotleak 1008	Pennwalt Corporation	C	6.80 lb.
Spotleak 1009	Pennwalt Corporation	C	6.76 lb.
Spotleak 1015	Pennwalt Corporation	D	6.70 lb.
Spotleak 1450	Pennwalt Corporation	C	6.80 lb.
Pennodorant 1005	Pennwalt Corporation	C	7.75 lb.
Pennodorant 1013	Pennwalt Corporation	C	8.33 lb.
Modified Spotleak 1009	Pennwalt Corporation	C	6.76 lb.
Spotleak Lot #1440	Pennwalt Corporation	C	6.80 lb.
Spotleak Lot #1007	Pennwalt Corporation	C	6.72 lb.
Scentinal F	Phillips Chemical Co.	C	6.79 lb.
Scentinal O	Phillips Chemical Co.	C	6.86 lb.
Scentinal E	Phillips Chemical Co.	C	6.77 lb.
Scentinal G (Con.)	Phillips Chemical Co.	C	7.04 lb.
Scentinal G (Dilute)	Phillips Chemical Co.	D	7.04 lb.
Scentinal D	Phillips Chemical Co.	C	6.70 lb.
Scentinal H-83	Phillips Chemical Co.	D	5.76 lb.
Scentinal S-20	Phillips Chemical Co.	C	6.80 lb.



—Equipment in which a portion of the main gas stream is diverted, by an orifice plate or partially closed valve in the line, through a tank provided with baffles or wicking. The odorant-saturated portion of the by-pass gas is then returned to the main stream. Generally used for low, more uniform flows.

—Equipment in which by-pass gas controlled by a precision valve is forced through a gas meter which drives a dipper type of pump that dips the odorant into the gas line.



Gas meter-driven odorizer

D. Monitoring Techniques

1. Periodically, at least once a year, operators should have a consultant run an odorometer test on the gas in the system to determine if it is properly odorized. (The best time would be when there is a low usage of gas by customers.) Operators should check with the RRC for additional requirements.
2. As an operating procedure, operators should include the requirement that sniff tests be made whenever a meter set, repair to system, or leak check is made. Written records of these tests should be kept on file.
3. Operators should make a sniff test at the extremities of system at least quarterly.

A sniff test is when one or more observers smells gas from an open valve or gas burner. The person's name, date, and location of where a test was conducted should be kept on file.

E. LP-Gas Operators' Requirements

All LP-Gases must be odorized by the addition of a warning agent of such character so that when gas is present in air at a concentration of as much as one-fifth of the lower explosive limit (192.625 A), the odor is readily detectable by a person with a normal sense of smell. The LP-gas should be odorized by your supplier before you purchase it. Use the bill of lading for evidence of odorant and then use the sniff test to verify the odorant is adequate on at least a quarterly basis. Again, if your system is LP-gas, the CGI should be calibrated for that type of LP-gas (propane, butane).

FILE WITH

RAILROAD COMMISSION OF TEXAS

—INSTRUCTIONS NEXT PAGE—

GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION

APPROVED SCHEDULE OF SERVICE AND MAINTENANCE FOR FARM TAP ODORIZERS

(1) COMPANY NAME ______________________

(2) REP. I.D. # ______________________

(3) ODORIZER LOCATION	(4) NAME OF MALODORANT	(5) CONCENTRATE OR DILUTE	(6) INSPECTION FREQUENCY	(7) INSPECTION PROCEDURE
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		

(CONTINUED - NEXT PAGE)

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 true, correct, and complete, to the best of my knowledge.

If Submitting Multiple Copies — Sign First Copy Only

____
Signature Date

____
Type or Print Name and Title

Telephone ________ ______________
(Area Code) Number

RRC FORM PS-9
Rev. 12/87

(Continued from Preceding Page)

(3) ODORIZER LOCATION	(4) NAME OF MALODORANT	(5) CONCEN-TRATE OR DILUTE	(6) INSPECTION FREQUENCY	(7) INSPECTION PROCEDURE
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
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		C or D		
		C or D		
		C or D		
		C or D		

INSTRUCTIONS: (1) Company Name
(2) Representative's Assigned I.D. Number
(3) Odorizer Location
(4) Name of Malodorant, i.e., B.P. Captan, etc.
(5) Concentrate or Dilute—Circle correct symbol, i.e., C or D
(6) Inspection Frequency—Minimum frequency is annually
(7) Inspection Procedure—Be definitive of normal inspection procedure and note all maintenance that is done.

RETAIN FOR COMPANY FILE

FORM PS—8
Rev. 12/87

RAILROAD COMMISSION OF TEXAS

GAS UTILITIES DIVISION

PIPELINE SAFETY SECTION

QUARTERLY ODORIZATION REPORT

ODORIZATION REPORT FOR
QUARTER ENDING ______

REP ID ______ ☐ 1 ☐ 2 ☐ 3 ☐ 4

PLEASE READ INSTRUCTIONS ON REVERSE SIDE BEFORE COMPLETING THIS FORM

(1) ODORIZER LOCATION	(2) PS-9	(3) NAME OF MALODORANT	(4) DILUTE OR CONCENTRATE	(5) AMOUNT INTRODUCED	(6) MMCF OF GAS ODORIZED	(7) RATE PER MMCF	(8) DATE REMOVED
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that the report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

______ SIGNATURE ______ DATE

______ TYPE OR PRINT NAME AND TITLE

TELEPHONE ______ AREA CODE ______ NUMBER

INSTRUCTIONS

This quarterly Odorization Report, Form PS—8, is to be retained for your company records and available for Commission inspection. The following instructions explain how to complete each numbered item on the face of this form.

NOTE: Before installation of any odorization equipment, read Rule 16 T.A.C. § 7.71.

IF the odorizer is shop made or not commercially available or approved according to Rule 16 T.A.C. § 7.71(d) (2), submit to the Railroad Commission, with RRC Form PS—25, plans and specifications in duplicate describing the equipment to be used for introducing the malodorant required by 16 T.A.C. § 7.71. The Railroad Commission shall indicate its approval or disapproval of such plans by written order.

ITEM 1. ODORIZER LOCATION. List your odorizer by location. Do not enter any other information or make any marks in this space.

ITEM 2. PS—9. If the assigned number in **ITEM 1** is for a wick type odorizer, applicable under the Farm Tap definition in 16 T.A.C. § 7.71 of" serving a consumer or consumers using not more than 10 MCF on an average day in any month," and is being serviced and maintained in accordance with an approved schedule (Form PS—9) on file with the Railroad Commission, mark an "X" in **ITEM 2**, then leave blank items 3, 4, 5, 6, and 7.

ITEM 3. NAME OF MALODORANT. Print name of malodorant used in the odorization of natural gas for the assigned odorizers.

ITEM 4. CONCENTRATE OR DILUTE. Circle C for concentrate or D for dilute and complete items 5, 6, and 7 on the same line across.

ITEM 5. AMOUNT INTRODUCED. Enter the amount of malodorant introduced in lbs. if concentrate, gals., if dilute.

ITEM 6. MMCF OF GAS ODORIZED. Number of **million** cubic feet of gas odorized.

ITEM 7. RATE PER MMCF. Rate of lbs. or gals. of malodorant introduced per MMCF of natural gas odorized. Use the following formula:

$$\frac{\textbf{AMOUNT INTRODUCED IN LBS OR GALS (ITEM 5)}}{\textbf{MMCF OF GAS ODORIZED (ITEM 6)}}$$

ITEM 8. DATE REMOVED. If the assigned odorizer has been removed or discontinued, enter date in month/day/year format.

EXAMPLE: October 23, 1978, removal date is shown in **ITEM 8** as 10/23/78.

READ THE CERTIFICATE, SIGN AND DATE THE REPORT, RETAIN IN COMPANY FILE.

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION
ODORIZATION EQUIPMENT INSTALLATION AND/OR APPROVAL FORM*

Applicant ________________	**FOR RRC USE ONLY** (6) Date Received: ________
Address: ________________	Log No.: ________
City: ____________ Zip: ________	Approval Date: ________
	Docket No.: ________

Check the box which applies to your situation and refer to the applicable section.

X. ☐ A commercial manufacturer submitting plans and specifications for RRC approval. COMPLETE SECTION A ONLY. Sign form.

Y. ☐ Gas company submitting plans and specifications for approval of shop-made odorization equipment not previously approved for use by applicant only. COMPLETE SECTIONS A AND B. Sign form.

Z. ☐ Gas company submitting plans and specifications for approval of shop-made odorization equipment for commercial availability. COMPLETE SECTIONS A AND B. Sign form.

SECTION A

BRAND NAME: ____________ MODEL NO.: ____________ TYPE (See Item 3 on reverse side): ____________

Attach to this form plans and specifications to include the following:

1. A detailed drawing of the odorizer, related piping, and valves used for standard installation.
2. Test data verifying the maximum flow rate (Mcf/day) at which the required injection rate will be adequately maintained and the injection rate for various flows.
3. The maximum operation pressure (design). Show calculations.
4. The actual working pressure. (Applies to Z. only)
5. Written standard installation instructions. (Include schematic if installation drawing is not clear.)

(See reverse side for Section B instructions.)

SECTION B

Gas Company Representative (1)

____

Street or P. O. Box

____

City | State | Zip Code | Area Code | Telephone #

Individual Odorizer Location	Odorizer Type (3)	Proposed Installation Date-Mo/Yr (4)	City, Area, System, or Facility Served (5)
Location			
County			

I, ____________________ do certify that this equipment will be installed and operated by the manufacturer's specifications.

Sections A & B must sign form.

____________________ Signature ____________ Date

____________________ Type or Print Last Name and Title

Telephone ________ A/C ____________ Number

RRC FORM PS-25
Rev. 12/87

* This form applies only to odorization equipment not previously approved by the Railroad Commission of Texas (See next page for details.)

This form is to be used by anyone planning to install odorization equipment not previously approved by the Railroad Commission of Texas. Gas Utilities Substantive Rule 16 T.A.C. § 7.71(d) states, "All gas companies shall utilize odorization equipment approved by the Railroad Commission of Texas. . ." Previously approved odorization equipment is listed under Commercially Available Equipment Approved by the Railroad Commission For Use in the State of Texas.

SECTION B - INSTRUCTIONS

ITEM 1 This is the person responsible for the company odorizer(s) listed in (2). Give the mailing address, city, zip code, and telephone number where he may be contacted. This must be the person and address to whom all correspondence regarding the listed odorizers will be directed.

ITEM 2 List the location of the odorizer or odorizers that will be reported under the address in Item 1. If there is no street address, indicate plant site, line ID number, mile pole, etc. **Be sure to indicate the county in which each odorizer is located.**

ITEM 3 Odorizer type as illustrated in Table below:

ODORIZER TYPE	CODE # FOR USE IN ITEM 3
Wick	1
Absorption bypass	2
Drip	3
Meter Drive Pump	4
Positive Displacement Pump	5
Other	6

NOTE: If the odorizer type is a "farm tap" as defined in 16 T.A.C. § 7.71(a)(3), complete Form PS—9, and return with this form.

ITEM 4 List the proposed installation date of each odorizer by month and year.

ITEM 5 List the city or section of a city, area, system or facility served (i.e., City of Raze, transmission line #6046, farm tap, dog house in plant B, etc.).

ITEM 6 FOR RRC USE ONLY
Upon approval, a copy of this form will be returned indicating the docket number in this box.

For additional forms, mail requests to:

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
P.O. DRAWER 12967
AUSTIN, TEXAS 78711-2967

RETAIN FOR COMPANY FILE

RAILROAD COMMISSION OF TEXAS

GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION

—INSTRUCTIONS NEXT PAGE—

APPROVED ODORANT CONCENTRATION TEST FORM

ODORANT CONCENTRATION METER METHOD

1. Odorizer Location ____________________
2. Location of Test ____________________
3. Distance from Odorizer ____________________
4. Test Date ____________________
5. Instrument Used ____________________
6. Serial No. ____________________
7. Test Time ____________________

8. Signature of Tester ____________________

Witnesses ____________________

____

9. Odor Concentration Meter Test [(B) x (D)] ________ % Gas in Air (Should be less than 1%)

(A) Odorant Concentration Meter Reading When Gas Odor Detected (Glass or Steel Float) ________

(B) % Gas in Air, Odorant Concentration Meter ________

(C) Specific Gravity of gas tested ________

(D) Correction Factor for Gravity ________

ROOM TEST METHOD

1. SIGNATURES OF TEST WITNESSES	3. METERED VOLUME OF GAS

2. SIGNATURE OF TESTER

METER READING
Beginning ________ Cubic Feet
Ending ________ Cubic Feet

(E) Volume of Test Room (L x W x H) ________ Cubic Feet

(F) Volume of Furniture [See (I)] ________ Cubic Feet

(G) Net Volume of Room (E-F) ________ Cubic Feet

(H) Average Metered Volume of Gas ________ Cubic Feet

4. Room Test (H G x 100) ________ % Gas in Air

(I) AVERAGE VOLUMES OF SPACE DISPLACED BY FURNITURE AND PEOPLE (CUBIC FEET)

1. Bed, Double	30	9. Divan, One Piece	20
2. Bed, Single	20	10. Divan, Sectional	25
3. Buffet	20	11. Dresser	10
4. Chair, overstuffed	10	12. Radio, Table Model	1
5. Chest of Drawers	15	13. Radio, Console	6
6. Cedar Chest	10	14. Table, Dining	2
7. China Cabinet	10	15. T.V., Table Model	5
8. Desk	8	16. T.V., Console	10
		17. One Person	3

REMARKS: ____________________

RRC FORM PS-6
Rev. 12/87

INSTRUCTIONS FOR RRC FORM PS-6

APPROVED ODORANT CONCENTRATION TEST FORM

ODORANT CONCENTRATION METER METHOD

1. Odorizer location(s) --- the odorizer being tested.
2. Location of test.
3. Distance from odorizer --- if this is a short distance, indicate why.
4. Test date.
5. Instruments used --- house meter, odor concentration test meter including type and brand.
6. Serial number.
7. Time of test.
8. Signature of tester.

   (A) Odorant Concentration Meter reading when gas odor detected.
   (B) % Gas in Odorant Concentration Meter --- some meters require a conversion by use of curves supplied with the instrument.
   (C) Specific Gravity of Gas Tested if other than specified by manufacturer.
   (D) Correction Factor for Specific Gravity if specific gravity is other than that specified by manufacturer.
9. Odorant Concentration Meter Method of Calculating % gas in air. The specific gravity of the gas being tested may affect the readout. To determine this, check with the manufacturer of the instrument being used. If gas with a specific gravity, other than that used in the calibration of the instrument, is being used, a correction factor may have to be applied. If so, the correction factor for specific gravity (D) will be multiplied by the % gas in odorant concentration meter (B) to get the correct % gas in air. **This number must be less than 1% or your gas lacks sufficient odor.**

ROOM TEST METHOD

1. Signatures of witness using a minimum of 3 witnesses.
2. Signature of tester.
3. Metered volume of gas at which point 3 witnesses and tester detected the gas odor.

   (E) Volume of Test Room --- length x width x height gives cubic feet.
   (F) Volume of furniture, etc. --- calculate by use of Table 1 or by measuring items not listed.
   (G) Net Volume of Room (E-F) --- subtract volume calculated in F from volume calculated in E.
   (H) Average metered volume of gas at which point 3 witnesses and tester detected gas odor.
4. Room Test method of calculating % gas in air --- divide (H) (average metered volume of gas) by (G) (net volume of room) and multiply by 100 to get % gas in air. **This number must be less than 1% or your gas lacks sufficient odor.**

* **This form will not be filed with the Commission. It will be kept on file in your office for inspection by our staff engineers.** The results of this test will be compiled on RRC Form PS-8A for each calendar year.

Appendix L

Pipeline Welding Requirements

How can I determine if my pipeline welding is performed as required?

Steps to Take:

A. Welding must be performed under established written welding procedures as appropriate to either Section 2 of API Standard 1104 or Section IX of ASME Boiler and Pressure Vessel Code. For typical pipeline welding, API 1104 would most likely be used and will be discussed herein.

The written welding procedure shall include:

1. Records of the complete results of the procedural qualification test.
2. Procedural Specification
   a. Identifying the process
   b. Identifying the materials
   c. Identifying the wall thickness groups
   d. Showing a joint design sketch
   e. Designating filler metal and number of beads
   f. Designating electrical characteristics
   g. Designating flame characteristics
   h. Designating position of roll welding
   i. Designating direction of welding
   j. Designating maximum time lapse between passes
   k. Designating type of line-up clamp and removal criteria
   l. Designating type of cleaning tools used
   m. Specifying preheat and post heat practices
   n. Designating composition of gas and range of flow rate
   o. Designating type and size of shielding flux
   p. Designating range of speed of travel for each pass
3. Essential Variables

   Most changes in A.2. above require requalification of the welding procedure (Refer to paragraph 2.4, API 1104).
4. Welding and Testing of Test Joint
   a. Preparation of Specimen
   b. Destructive Tests — Butt Welds
      (1) Tensile Strength Test
      (2) Nick Break Test

(3) Root and Face Bend Test

(4) Side Bend Test

c. Destructive Test — Fillet Welds

Break in Weld as specified

B. Welding must be performed by welders who are qualified for the welding procedure to be used.

1. The welder shall be qualified under one of the applicable requirements specified.

a. Transmission Pipelines

(1) Section 3 of API 1104; or

(2) Section IX of ASME Boiler and Pressure Vessel Code.

b. Distribution Pipeline

(1) Section 3 of API 1104;

(2) Section IX of ASME Boiler and Pressure Vessel Code; or

(3) Section I of Appendix C, 49 CFR 192 (Not acceptable for service line to main connection welding).

c. Service Line Connections to Mains

(1) Section 3 of API 1104;

(2) Section IX of ASME Boiler and Pressure Vessel Code; or

(3) Sections I and II of Appendix C, 49 CFR 192.

2. Welder qualification under Section 3 of API 1104

a. Perform qualification test as specified in the written welding procedure in the presence of your company's representative.

b. Essential Variables (certain changes require requalification)

(1) For single qualification refer to 3.11 of API 1104; or

(2) For multiple qualification refer to 3.21 of API 1104.

c. Welding and Testing of Test Joint

(1) Preparation of Specimen(s)

(2) Visual Examination

(3) Destructive Tests — Butt Welds

Determine if all or part of these tests are required:

(a) Tensile Strength Test

(b) Nick Break Test

(c) Root and Face Bend Test

(d) Side Bend Test

(4) Destructive Tests — Fillet welds

Break in weld as specified

(5) Visual Inspection

NOTE: Nondestructive radiographic inspection of Butt Welds only can be done in lieu of Section c.(3) above. This is your option. Welders qualifying by nondestructive testing cannot weld on compressor station pipe and components. The standards of acceptability for radiographic inspection are specified in paragraph 6.0 of API 1104.

d. Keep the following records

(1) Detailed test results for each welder

(2) Test of qualified welders and the procedure(s) for which they are qualified

3. Welder qualification under Section I of Appendix C, 49 CFR 192

a. Perform qualification test on pipe 12" or less in diameter

b. Use position welding

c. Preparation must conform to written welding procedure

d. Destructive Test

Root Bend Test

e. Visually inspect

f. Keep the following records:

(1) Detailed test results for each welder

(2) Test of qualified welders under this procedure

4. Welder qualification under Sections I and II of Appendix C, 49 CFR 192

a. Perform Section B.3. above

b. Weld service line connection fitting to a pipe typical of your main using similar position as you would in actual production welding

c. Destructive Test — Break (or attempt to break) the fitting off the run pipe

d. Visually inspect

C. A welder must be requalified before doing production welding when:

1. Initially qualified under Section 3 of API 1104 or Section IX of ASME Boiler and Pressure Vessel Code if within the preceding six calendar months he has not welded with the particular welding process (either test or production welding is acceptable). He may perform a modified test by having one weld tested satisfactorily either destructively or nondestructively (Refer to Section B.2.c. for required procedure).

2. Initially qualified under either Section I or II of Appendix C if:

   a. Within the preceding 7 1/2 calendar months he has not had one production weld cut out, tested, and found acceptable in accordance with the initial qualification test; or

   NOTE: Welders who work only on service lines two inches or smaller in diameter may be tested in each 7 1/2-month period under Section III of Appendix C in lieu of Section B.2.a. above.

   b. Within the preceding 12 calendar months, he has not qualified under Appendix C.

D. **Production Welding**

1. Use a qualified welder in a qualified welding procedure.

2. The following items should be part of the written welding procedure:

   a. Weather protection (192.231)

   b. Preparation (192.235)

   c. Visual Inspection (192.241)

   d. Nondestructive Testing (Under specified conditions) (192.243). Must meet standards of acceptability in Section 6 of API 1104.

3. Miter Joint Restrictions are when:

   a. MAOP produces a hoop stress of 30% or more of SMYS, the joint cannot deflect the pipe more than 3°.

   b. MAOP produces a hoop stress of more than 10% of SMYS but less than 30%, the joint cannot deflect the pipe more than 12 1/2°, and must have at least one pipe diameter separation from another miter joint.

   c. MAOP produces a hoop stress of 10% of SMYS or less, the joint cannot deflect the pipe more than 90°.

4. Repair or removal of defect requirements are as follows:

   a. Remove or repair all welds that fail to pass the nondestructive test requirements (Standards of acceptability in Section 6 of API 1104).

   b. Remove all welds which contain cracks that are 8% or more in length, or that penetrate either the root or second bead.

   c. Repairs must have the defect removed down to clean metal and the segment to be repaired must be preheated. Inspect the repaired weld. If the repaired weld is not acceptable, it must be removed.

Appendix M

Plastic Pipe

A. Plastic Pipe; Qualifying Joining Procedures (192.283)

1. Heat Fusion, Solvent Cement, and Adhesive Joints.

   Before any written procedure established under 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

   a. The burst test requirements (192.283) of Paragraph 8.6 (Sustained Pressure Test) or Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513;

   b. For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

   c. For procedures intended for nonlateral 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 percent or failure initiates outside the joint area, the procedure qualifies for use.

2. Mechanical Joints. Before any written procedure established under 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five specimen joints made according to the procedure to the following tensile test:

   a. Use an apparatus for the test as specified in ASTM D638-77a (except for conditioning).

   b. The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

   c. The speed of testing is 5.0 mm (0.20 in.) per minute, plus or minus 25 percent.

   d. Pipe specimens less than 102 mm (4 in.) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

   e. Pipe specimens 102 mm (4 inch) and larger in diameter 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 55° C (100° 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.

f. Each specimen that fails at the grips must be retested using new pipe.

g. 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 but with a lesser wall thickness.

3. A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

4. Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

B. Plastic Pipe; Qualifying Persons to Make Joints (192.285)

1. No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

   a. Appropriate training or experience in the use of the procedure; and

   b. Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph 2. of this section.

2. The specimen joint must be:

   a. Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

   b. In the case of a heat fusion, solvent cement, or adhesive joint:

      (1) Tested under any one of the test methods listed under 192.283(a) applicable to the type of joint and material being tested;

      (2) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

      (3) Cut into at least three longitudinal straps, each of which is:

         (a) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

         (b) Deformed by bending, torque, or impact, and, if failure occurs, it must not initiate in the joint area.

3. A person must be requalified under an applicable procedure, if during any 12-month period that person:

   a. Does not make any joints under that procedure; or

   b. Has three joints or three percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under 192.513.

4. Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

Appendix N

Design Terminology

Hoop Stress is the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid in the pipe. Hoop stress in pipe is calculated by the formula:

$$S_h = \frac{PD}{2t}$$

S_h = hoop stress, psi
P = internal pressure, psig
D = outside diameter of pipe, inches
T = Nominal wall thickness, inches

SMYS means specified minimum yield strength.

Appendix O

Service Line Drawings, Main Connection Testing, and Simple Repair Clamps

Introduction

This Appendix contains the following:

1. Sample drawings of some typical service line drawings with their main connections.

   NOTE: These are for illustration purposes only. There are many other acceptable ways to put together a service. Make sure a qualified person designs your mains and services.

2. Pressure testing requirements for services and mains.
3. Two illustrations of some simple repair clamps for use on steel pipe. Instructions for their installation are included.

   NOTE: There are hundreds of repair fittings on the market. Have a qualified person select the best one for your system.

TEST CONDITIONS FOR SERVICE LINES				
	Other Than Plastic			Plastic
Maximum operating pressure	Less than 1 psig	1 psig to 40 psig	Over 40 psig but less than 100 psig	0-100 psig
Test Medium	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (1)
Maximum test pressure	See Note (2)	See Note (2)	See Note (2)	3 X design pressure
Minimum test pressure	See Note (3)	50 psig	90 psig See Note (4)	50 psig or 1.5 X maximum operating pressure whichever is greater
Recommended minimum test duration	5 Minutes	5 Minutes	See Note (4)	5 Minutes

Notes: For sample form See Appendix D, Form 113.1

(1) Temperature of thermoplastic material must not exceed 100° F during test.

(2) Refer to 192.503(c) for limitations for testing with air, natural gas or inert gas. Limited also to the design pressure of service line component (192.619).

(3) Recommended practice is a minimum of 10 psig.

(4) Whenever test pressure stresses pipe to 20 percent SMYS or more, see 192.511(c) for additional requirements.

(5) LP-Gas may not be used as a test medium.

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES[1]

This table is presented as a guide to the application of the test requirements in 49 CFR 192.65, 192.143, 192.503, 192.505, 192.513, and 192.619 as they apply to pipelines other than service lines.

	Other Than Plastic				Plastic
	Under 30% SMYS			30% SMYS[2] and over	
Maximum operating pressure	Less than 1 psig	1 psig but less than 100 psig	100 psig and over[2]	All pressures	All pressures
Test medium	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas Note (1)	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas Note (2)
Maximum test pressure	See Note (3)	See Note (3)	See Note (3)	See Note (3)	3 X design pressure
Minimum test pressure	10 psig	90 psig	Maximum operating pressure multiplied by class location factor in 192.619 (a)(2)(ii) See Notes (1) & (4)	Maximum operating pressure multiplied by class location factor in 192.619 (a)(2)(ii) See Notes (4) & (5)	50 psig or 1.5 X maximum operating pressure whichever is greater
Minimum test duration	See Note (6)	See Note (6)	1 Hour and See Notes (4) & (6)	8 Hours and See Notes (6) & (7)	See Note (6)

[1]Information derived from ASME Guide for Gas Transmission and Distribution Piping Systems—1980.

[2]This column will normally not apply to a master meter operator.

NOTES: to preceding table (all numbered references are to Title 49, CFR), Part 192:

(1) Whenever test pressure is 20 percent SMYS or greater and natural gas, inert gas or air is the test medium. The line must be checked for leaks either (a) by a leak test at a pressure greater than 100 psig but less than 20 percent SMYS or (b) by walking the line while the pressure is held at 20 percent SMYS [192.507(b)].

(2) Temperature of thermoplastic material must not exceed 100° F during test.

(3) Refer to 192.503(c) for limitations when testing with air, natural gas or inert gas. (There are no limitations for water test.) For all test media, strength of all pipeline components in test section must be taken into consideration when determining the maximum test pressure.

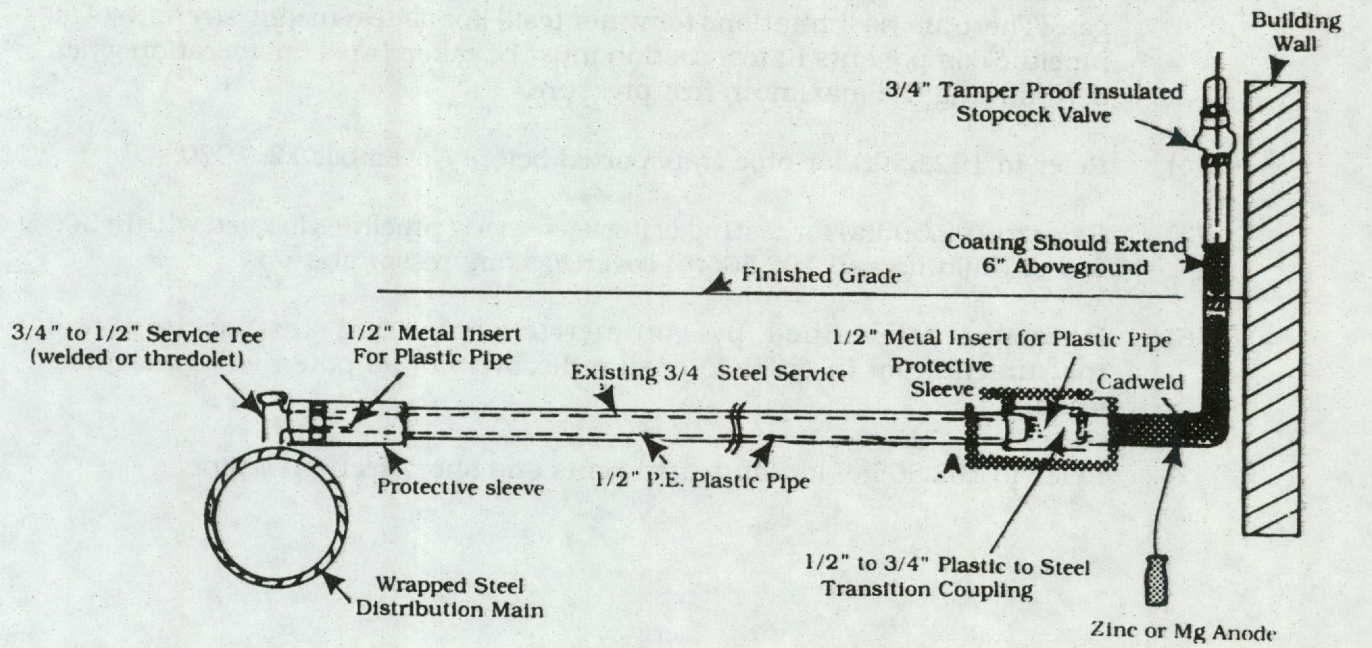
(4) Refer to 192.65(b) for pipe transported before November 12, 1970.

(5) Refer to 192.505(a) for testing criteria covering pipelines located within 300 feet of building and 192.505(b) covering compressor stations.

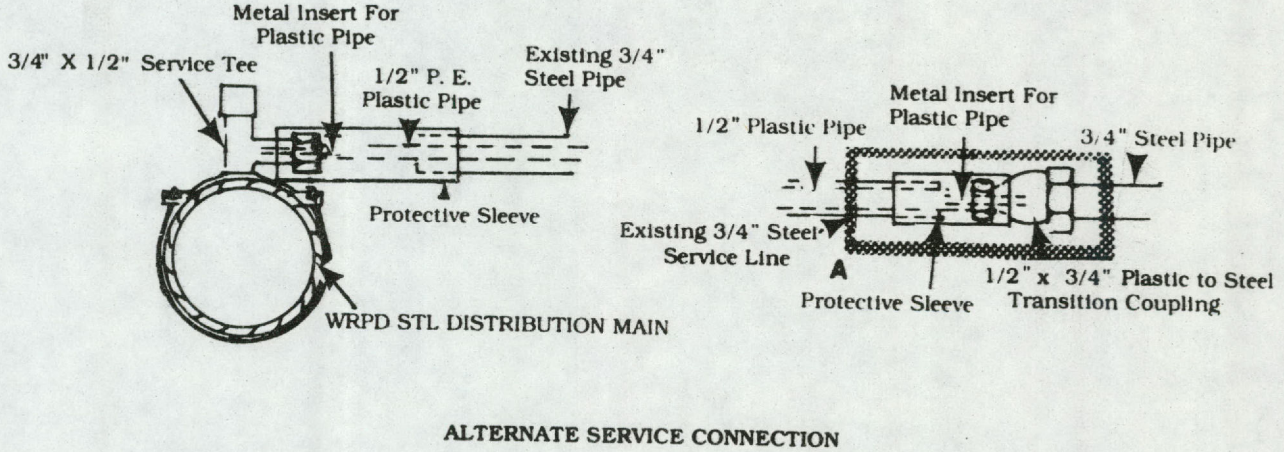
(6) Duration determined by volumetric content of test section and instrumentation in order to ensure discovery of all potentially hazardous leaks.

(7) Refer to 192.505(e) for fabricated units and short section of pipe.

Example of a 1/2" Plastic Pipe Inserted into a 3/4" Existing Service Line
(For illustration purposes only)

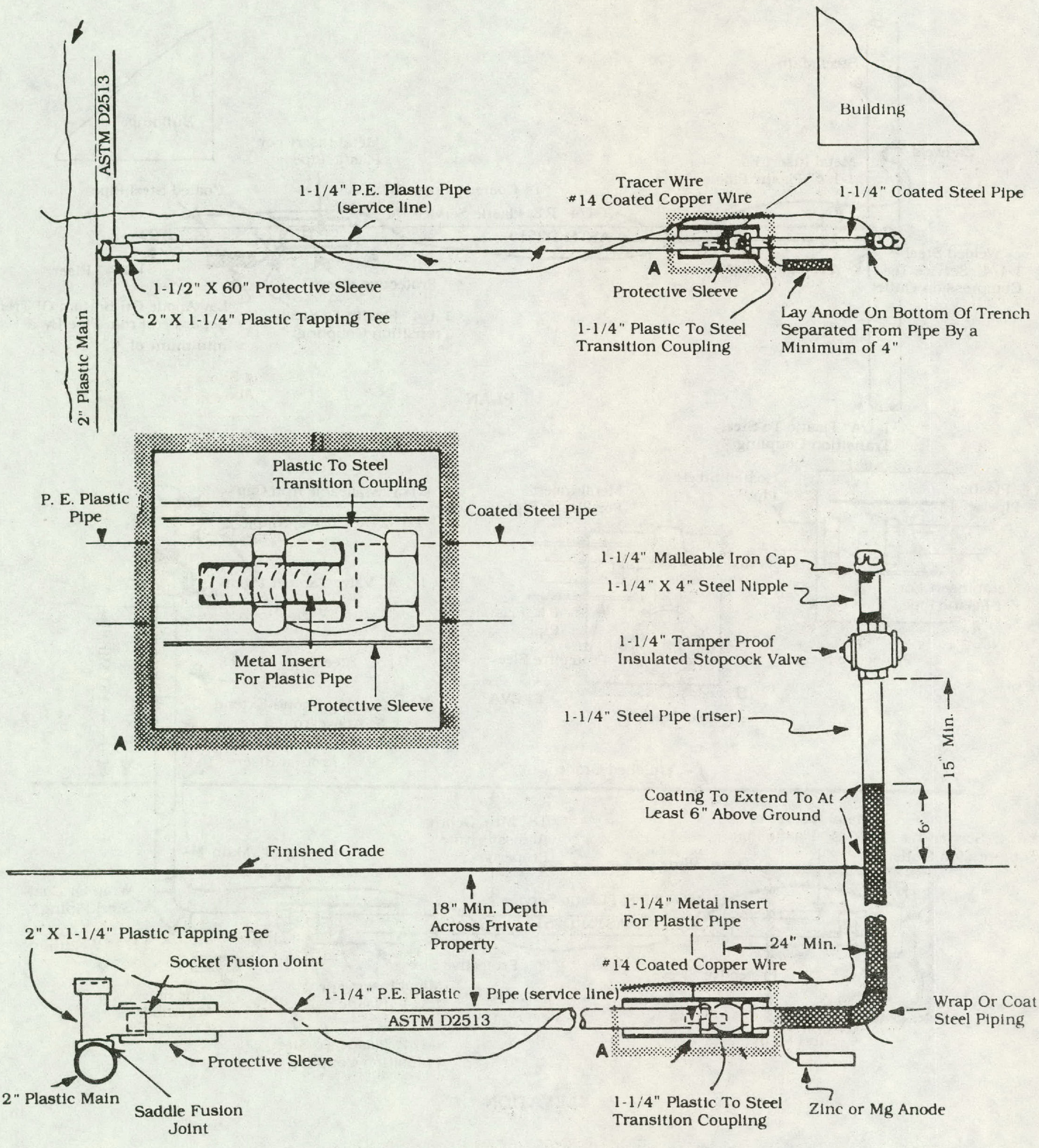


ELEVATION

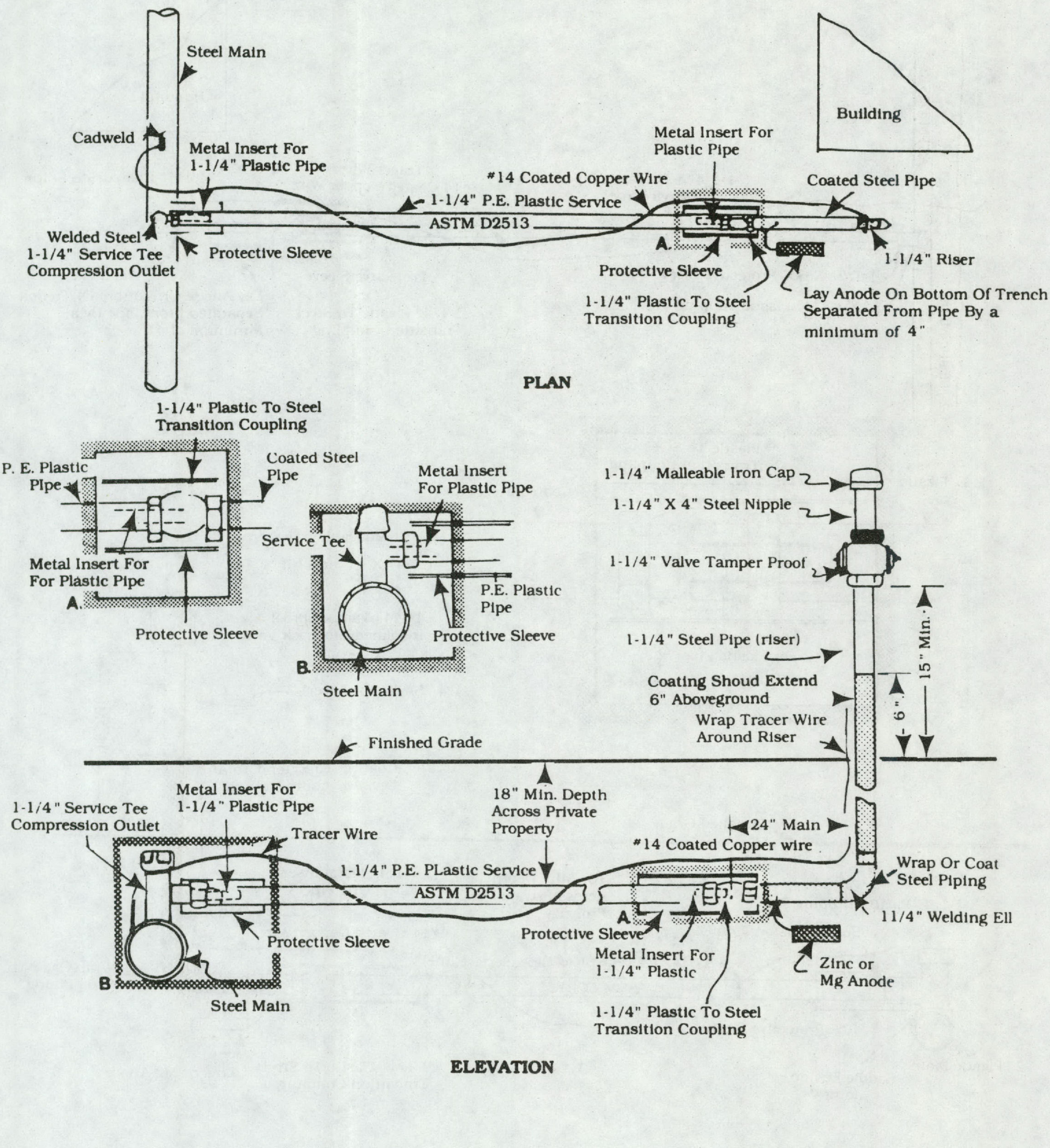


ALTERNATE SERVICE CONNECTION

1 1/4" Plastic Service Line From 2" PE Plastic Main
(For illustration purposes only)

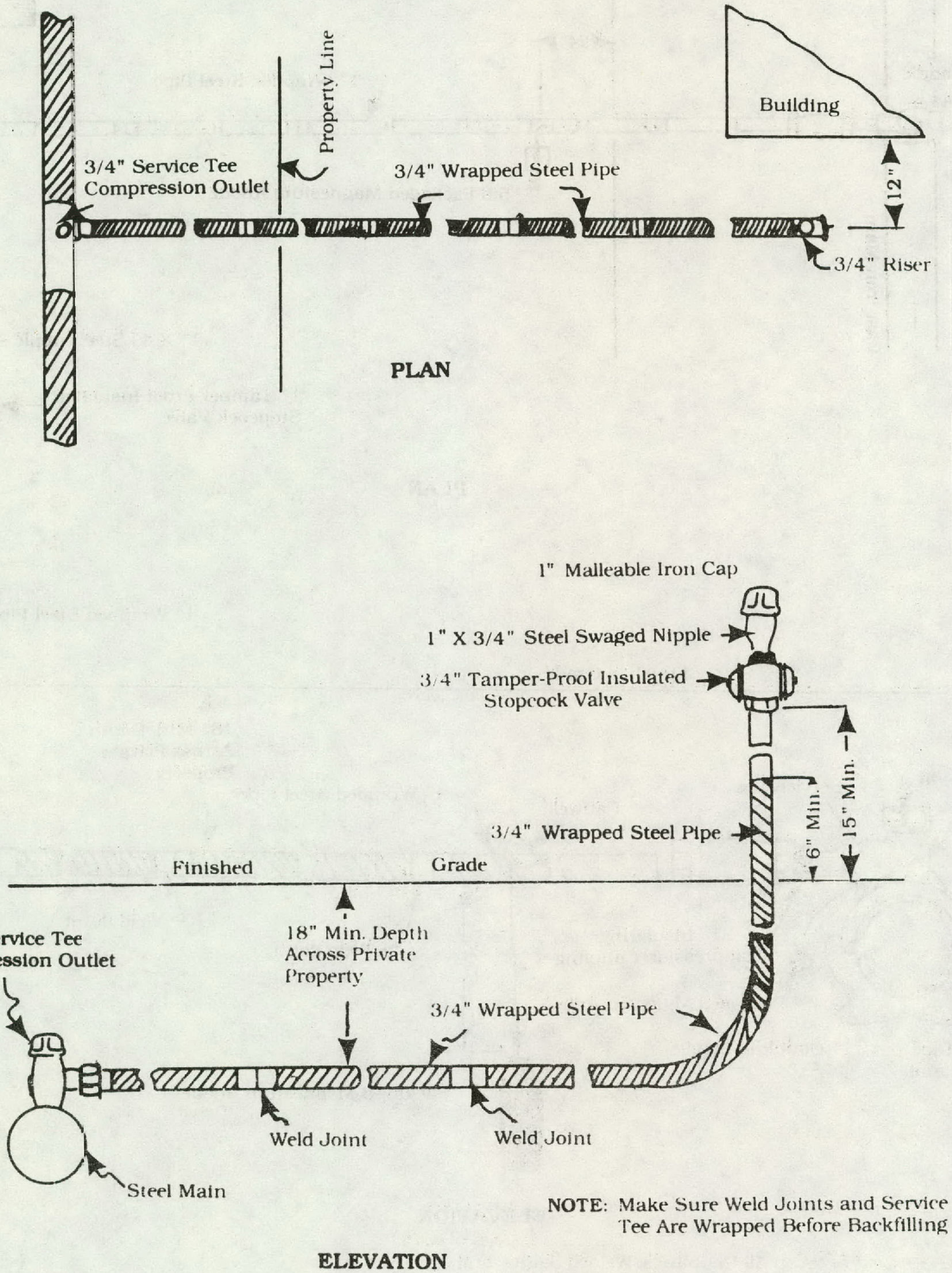


1 1/4" PE Plastic Service Line From Steel Main
(For illustration purposes only)

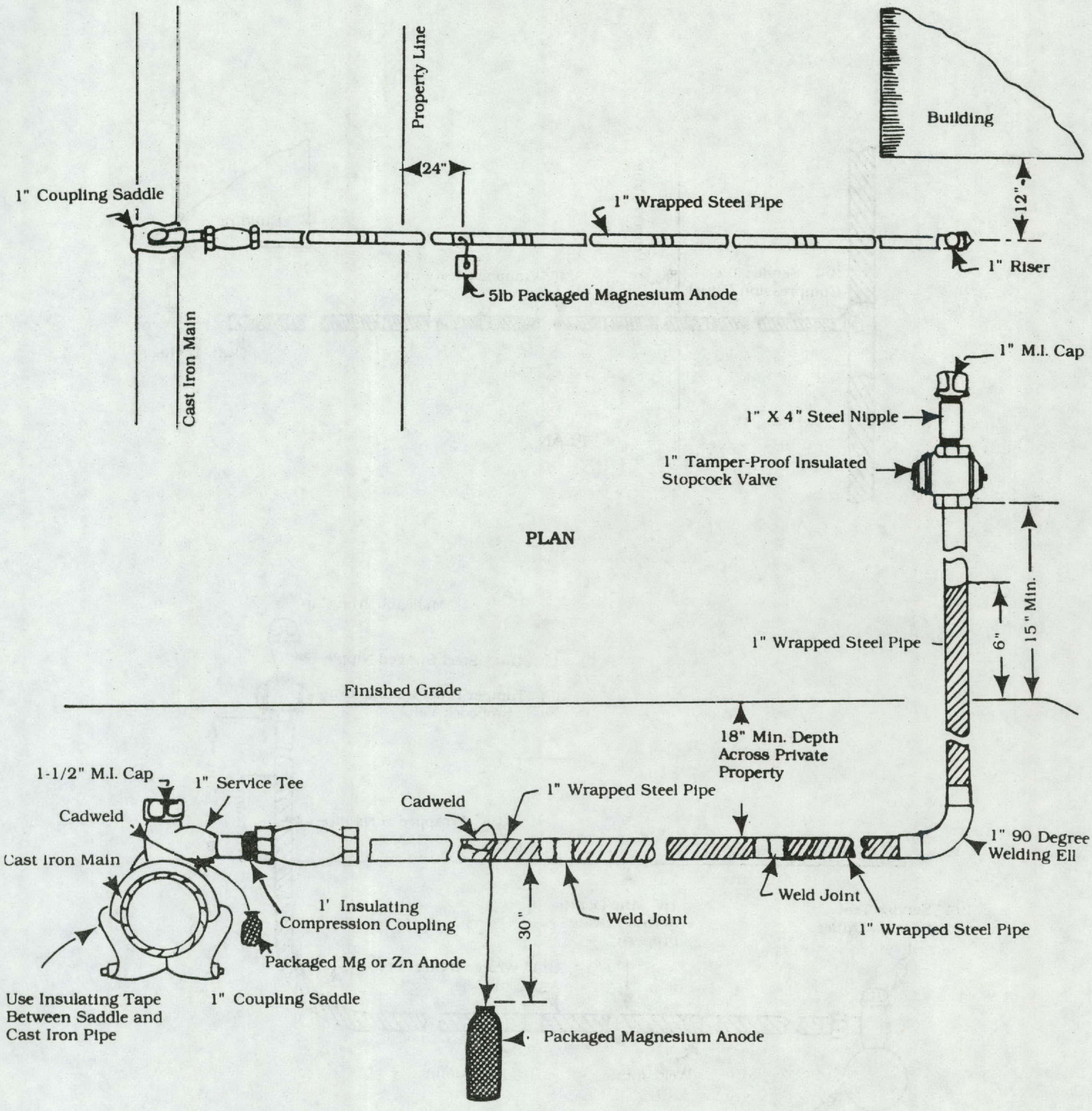


Welded 3/4" Service Line From Steel Main

(For illustration purposes only)



Welded 1" Service Line From Cast Iron Main
(For illustration purposes only)

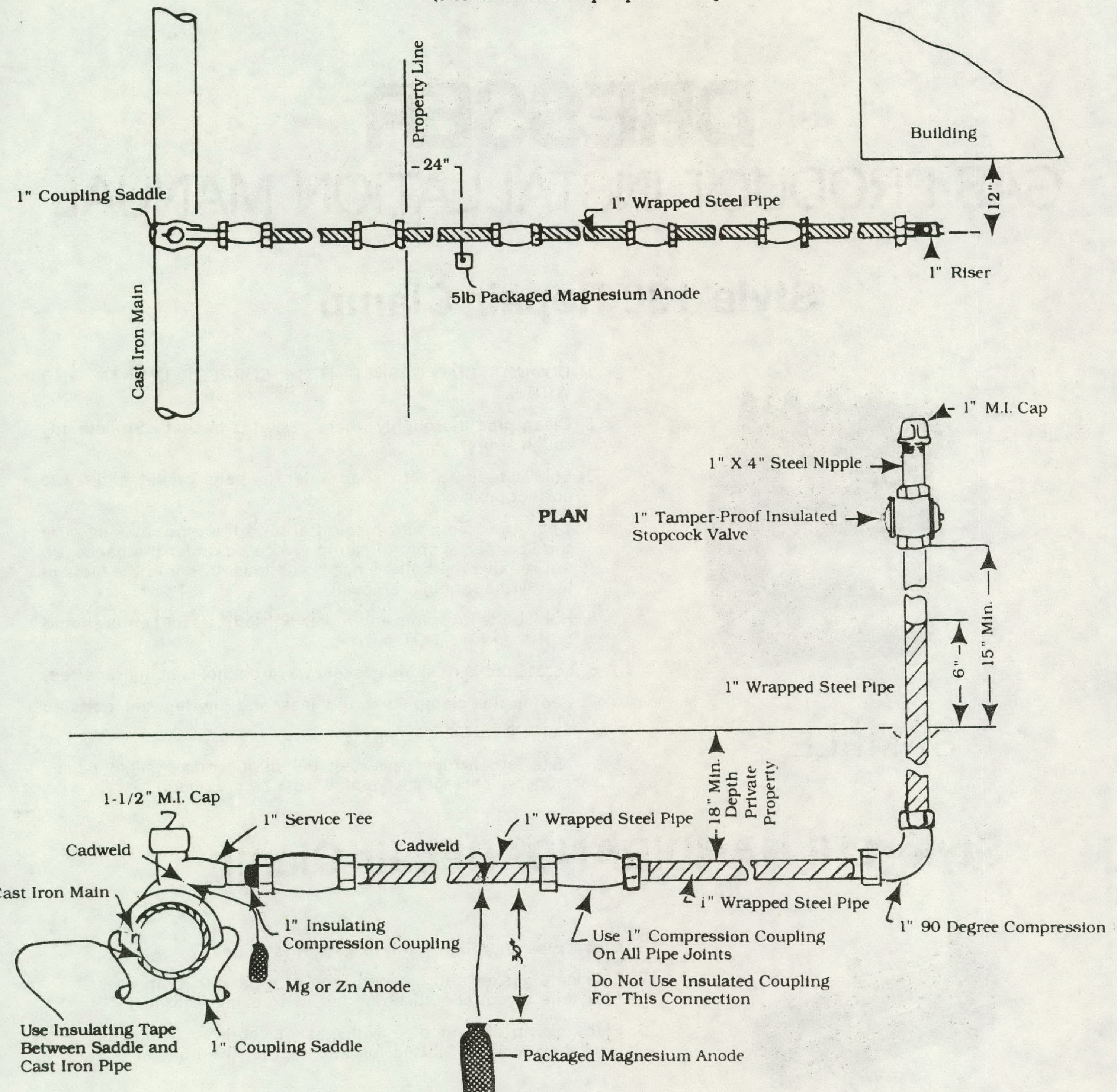


ELEVATION

NOTE: Coat or Wrap All Couplings, Welded Joints, and the Service Tee Before Backfilling.

Non-Welded 1" Service Line From Cast Iron Main

(For illustration purposes only)



ELEVATION

NOTE: Coat or Wrap All Couplings, Welded Joints, and the Service Tee Before Backfilling.

These are simple repair clamps which are useful in repairing small underground corrosion leaks.

DRESSER
GAS PRODUCT INSTALLATION MANUAL

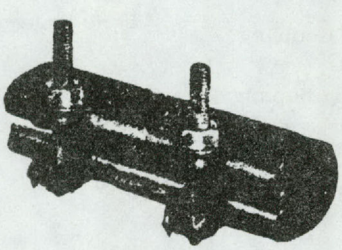
Style 130 Repair Clamp

SAMPLE

1. DO NOT CUT GASKET—IT IS CORRECT LENGTH AND WIDTH.
2. Clean pipe thoroughly where gasket is to seat. Smooth any rough spots.
3. Lubricate pipe with soap-water to help gasket slide into correct position.
4. Open the clamp and place it around the pipe, making sure the spanner at split of clamp is located under the band. Do not remove the bolts, since bolt heads drop into the slots in lugs without being removed.
5. Hook bolts into slots and finger-tighten. Gasket ends should butt together—NOT overlap.
6. Locate the joint in the gasket away from holes being repaired.
7. Center the clamp over the leak and tighten the bolts to 50 ft. lbs. torque.

Note: When pipe movement out of the clamp might occur, proper anchorage of the pipe must be provided.

Style 118 HANDIBAND® Repair Clamp



1. Clean pipe thoroughly where gasket is to seat.
2. Lubricate gasket and cleaned area of pipe with soap-water (ethylene glycol should be added in freezing weather).
3. Place clamp around pipe with gasket centered over leak. Hook bolt head in slotted lug and tighten the nut.

Appendix P

Pipeline Safety Enforcement

A. Introduction

This outline describes the enforcement authority and sanctions available to the Railroad Commission for achieving and maintaining pipeline safety. Included are the procedural steps involved in the exercise of that authority and the imposition of penalties for noncompliance.

Any person who is the subject of enforcement action described in this outline may employ legal counsel at all stages of any proceeding.

B. Jurisdiction and Penalties

1. All gas pipeline facilities within the borders of this state which are not subject to exclusive federal control are subject to regulation by the Railroad Commission. This broad jurisdiction includes the power to adopt regulations and rules, to require records to be maintained and reports to be made, to inspect records and facilities, and to enforce compliance with established safety standards.

   Basic authority for this jurisdiction is set out in art. 6053-1(a) of the Texas statutes, and extends to the Natural Gas Pipeline Safety Act of 1968, to 49 CFR 192 regulations, and to rules of the Railroad Commission.

   This jurisdiction specifically includes gas pipeline facilities owned and/or operated by an incorporated city, town, or village (See TEX. ATT'Y GEN. OP. No. M-542 (1970)).

2. Art. 6053-1(c) provides for the basic penalties for noncompliance with the safety standards.

   The Attorney General of Texas is authorized to enforce penalties recommended by the Commission to include the following:

   a. Injunction against continuing the violation.

   b. Injunction to stop the transportation of gas.

   c. Injunction to stop the operation of a pipeline facility.

   d. Fines of up to $1,000 per violation, per day, up to a total of $200,000.

   e. Additionally, art. 6057(b) provides for penalties against any owner, officer, director, agent, or employee of a utility, who wilfully violates any provision of the statutes of this state governing the utility. These penalties against individuals include fines of up to $1,000, and imprisonment for up to six months.

   f. Finally, art. 6062 provides for fines of up to $1,000 per offense, per day, against a utility failing to perform any duty therein imposed or to comply with any valid order of the Commission. Also, the Commission is authorized, under art. 6063, to place a utility in receivership, through court action, when deemed to be in the public interest.

C. Inspection and Enforcement

1. Any pipeline facilities and records, including employee qualifications for certain specified tasks (welding, joining, corrosion control) that are subject to the jurisdiction of the Railroad Commission, may be inspected at any time pursuant to one of the following:

   a. Routine scheduling, by either the Headquarters office or the appropriate regional office of the Commission's Pipeline Safety Section.

   b. A complaint received from a member of the public.

   c. Follow-up inspection, based on information derived from previous inspections.

   d. Pipeline facility accident or incident.

   e. Fact-finding visits, for purposes such as jurisdictional questions.

   f. Whenever deemed appropriate by the Commission, the Director of the Gas Utilities Division, or Director of the Pipeline Safety Section.

2. Any alleged violations or deviations from safety standards discovered during a safety evaluation or other inspection will be communicated in writing to the operator of the facilities. The operator is required to acknowledge the inspection report within the time limit set by the Commission, providing explanations and corrective actions as required.

3. The operator's explanations and plan of corrective actions will be reviewed by the Commission's Pipeline Safety Section. Any deficiencies or inadequacies will be brought to the attention of the operator for further corrective or remedial action by the operator.

4. Any failure of an operator to timely correct alleged violations of safety standards will be referred to the Commission's legal staff for compliance actions.

5. Legal compliance actions will normally consist of the following:

   a. Communication from the legal staff to the operator of the requirement to comply, and of the penalties involved in non-compliance.

   b. Conference, if necessary, to discuss the alleged violation(s), interpretations of safety requirements, and acceptable correction actions.

   c. Formal Hearing. If the matter cannot be resolved by agreement in conference, a formal hearing will be set, with proper notice issued, together with the issuance of subpoenas, where necessary.

   The hearing may result in a Commission order that directs the operator to comply, and sets appropriate fines or other penalties recommended to the Attorney General for enforcement.

Appendix Q

Damage Prevention Program — Questions and Suggestions

When was the program effective?

April 1, 1983

Which operators must have a program?

1. Private and municipal gas distribution for all lines in standard Class 3 & 4 areas.
2. Gas transmission lines, direct sales, and gathering lines in standard Class 3 & 4 areas.

Which gas operators are exempt?

1. Master metered (resale).
2. Petroleum gas systems.

What line segments and other facilities are exempt?

1. All lines and facilities in Class 1 & 2 areas.
2. Lines and other facilities physically controlled by the operator.
3. Lines and other facilities in Class 3 locations **defined by the 100 yard/20 or more person rule.**

What are the program requirements?

1. Written program.
2. Identify current persons who normally engage in excavation, blasting, structure removal activities.
3. Provide for general notification of the public.
4. Provide for actual notification of persons involved in excavation activities, etc.
   a. Program's existence and purpose.
   b. How to learn the location of pipelines prior to excavating, etc.
5. Provide means of receiving and recording notification.
6. Provide for actual notification of persons who give notice.
   a. Location of buried lines.
   b. Type of temporary marking.
   c. Identifying characteristics.
7. Provide temporary marking.
8. Provide for inspection.
   a. Verify pipeline integrity.
   b. Leakage surveys for blasting.

What is meant by standard Class 3 & 4 areas?

1. Class 3 — An area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline that has 46 or more buildings intended for human occupancy.

2. Class 4 — The same area as above where buildings with four or more stories are prevalent.

3. Exceptions for full mile unit for Class 4 and, where cluster of buildings exist for Class 3, both may end 220 yards from the nearest building.

What is meant by the Class 3 "100 yard/20 or more person rule"?

1. A Class 3 location may be defined as an area where the pipeline lies within 100 yards of any of the following:

   a. A building that is occupied by 20 or more persons during normal use.

   b. A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month perod. (The days and weeks need not be consecutive.)

Suggestions for Planning and Implementing an Efficient Program

1. Review your class locations and match required program areas with city or county boundaries.

2. Join a "One Call System" or if none in your operating area, work with others to gain a multiple county or state-wide system (See Appendix R).

3. Establish a written program outlining procedures which will be performed by the "One Call System" and which will be performed by your representative.

   For example: "One Call System" to annually identify persons normally engaged in excavation activities, etc., including contractors, utilities, street and highway departments, etc.

   "One Call System" to provide for periodic notification of the public through the printed media.

   "One Call System" to annually contact identified parties to explain program's existence and purpose, and how to learn the location of facilities in your area prior to construction.

   "One Call System" to provide an answering and recording service for notifications.

   Your city or company to provide actual notification to persons giving notice of location to be affected, if any, type and characteristics of temporary markers to be provided, and any other special requirements including inspection procedure.

4. Prepare these procedures in written form and include "One Call System" documents when appropriate.

5. Periodically review these procedures and ensure they are followed whether performed by you or a **"One Call System."**

Appendix R

Checklist and Criteria For Establishing a One-Call Center

I. Checklist

A. Obtain input from government requirements (192.614) or other officials with knowledge of operating One-Call Centers.

B. Call meeting of gas transmission and distribution companies, pipeline companies, electric, telephone, municipal and other utilities to discuss concept of statewide automated Underground Utility Protection System to reduce damage to underground plant and accidents caused by dig-ins.

C. Establish Operating Committee with representatives from the major operator groups (gas, electric, telephone, pipeline, municipal authorities, etc.).

1. Select representatives who will be active and are positive about a statewide, automated one-call system.

2. Duties:

    a. Determine if a nonprofit corporation will be established to engage contractor or if the operators will deal directly with a contractor-sponsored system.

    b. Select name of One-Call Center.

    c. Visit one or more statewide, automated One-Call Centers to gain familiarity with Center operations and member organizational structure and operation.

    d. Develop criteria for operation of a One-Call Center.

    e. Develop plan and budget for the first year of operation.

    f. Develop potential membership list.

    g. Send membership letter to prospects for commitment of funds.

    h. Select Director if a nonprofit organization is to be formed.

    i. Select contractor/system to operate the One-Call Center.

    j. Oversee the installation and operation of the One-Call Center.

    k. Reserve easy to remember phone numbers for the One-Call Center, both local and WATS.

    l. If a nonprofit organization is to be established, form a Legal Committee with legal representatives from prospective member companies.

        Duties:

        (1) Establish a nonprofit corporation for statewide underground utility protection.

            (a) Elect Board of Directors and officers.

            (b) Establish local and meeting frequency of Board meetings.

(c) Establish subcommittees (operating, legal, public relations).

(2) Direct efforts in establishing the state legislation, if needed.

D. Establish Public Relations Committee with PR staff representing companies on the Board. Develop a public relations campaign to inform the state excavators about the statewide One-Call System and to solicit owners of underground facilities to become members of the statewide One-Call System.

E. If a contractor-sponsored center is used rather than a nonprofit organization, many of the above activities would be provided by the contractor. Underground utility operator's participation would be essential in PR activity.

II. Criteria

A. The system should be statewide in design and operational concept.

B. The One-Call Center's operation, with location and all computer and communication equipment, should be located in the state.

C. The system should use the latest in computer and communication software and equipment technology. It should be fully automated for receiving, reporting, and distributing locate request messages and managing all information received by the Center.

D. The system should have a high degree of functionality. It should be written in high-level language that maximizes machine independence; that is COBOL and/or FORTRAN, using multiple index access techniques. These include index sequential, direct, sequential and random.

E. The system should be capable of supporting a grid system of a quarter square mile or less for identifying location of underground plant by member companies.

F. The system should be capable of locating a grid cell by street address, cross street or grid coordinates.

G. The system should be designed to allow members to build or make changes to their data base on-line without affecting the system's operation.

H. The system should allow members to retrieve previous locate requests within a specified period of time.

I. The system should allow members to receive management reports, on-line, upon request, using compatible terminal equipment.

J. The system should allow members direct access to Center computer information data base on an interactive basis, using compatible terminal equipment.

K. The system should be designed to monitor the automatic locate request message distribution and report and discrepancies to the Center Director.

L. The information on the locate request message should be in a structured and comprehensive format.

M. The operation of the Call Center and the One-Call software should be easily handled by clerical personnel with minimal training.

N. The system should have an extensive audit trail for all automated functions, such as message distribution and maintenance.

O. A comprehensive training course should be developed to explain the overall operation of the One-Call Center as well as detailed operational characteristics of operating the member terminals. This course should include training manuals for the Call Center operators and member companies with terminal equipment.

P. The system should be designed to allow on-line entry and retrieval of damage information reporting.

Q. Locate request messages should be transmitted by priority (notice time). The locate request message should identify priority type on the message and initiate audible alarms on member terminals for emergency and priority messages.

R. The system should be capable of differentiating between messages sent to automated and nonautomated members.

S. All locate request messages should identify all members receiving the same message.

T. The system should allow for future changes in operational procedures or management reporting and allow growth in member and message volume. The system's software should support five-year growth in Call Center activity with minimum changes.

U. Members acting as excavators should be able to enter their own locate requests directly into the computer system via a terminal without having to call the One-Call Center.

V. The system should have the capability of interfacing with computer system used by large excavators for entering locate request information.

EXAMPLE FORMAT FOR MESSAGE

Messages sent to office(s) as follows:

Gas Company	Electric Company	Water/Sewer Company
Water Company	Telephone Company	Video Cable Company

Prepared by: *M. L. Fegenbush, Jr.*

Locate Request # $\overset{1}{\boxed{0004}}$ - $\overset{2}{\boxed{1015}}$ - $\overset{3}{\boxed{12}}$ - $\overset{4}{\boxed{8}}$ - $\overset{5}{\boxed{4}}$

1. Sequential # for that day
2. Time of Day
3. Day of Month
4. Month
5. Year

Location: County: *Travis* Town: *Austin*

Address: *55 North IH 35*

Beginning Work Date: *8-1-84* Time of Day: *8:30 a.m.*

Duration: *one day* Type of Excavation: *gas line*

Nature of Work: *Installing new service line*

Blasting: *No* 48-Hour Notice: *Yes*

Person Calling: *Ruby Judge* Name of Company: *ABC Gas Co.*

Work being done by: *ABC Gas Co.* For: *ABC Gas Co.*

Person to Contact: *Ruby Judge* Best Time to Call: *8:00 a.m. — 5:00 p.m.*

Phone # *512/475-0461*

Remarks: *Would like to meet utility representative at the intersection of Lamble and IH 35 access road at at 1:00 p.m. on 8-9-84.*

Located by ______________________ Date Located ______________

Remarks: ____

Excavator Notified ______________________________________

Notified by ____________________ Date ______________ Time ______________