CHAPTER C6
GAS SYSTEMS PIPING

Peter H.O. Fischer
Pipeline Project Manager
Bechtel Corporation
San Francisco, California

INTRODUCTION

General

Natural gas is the cleanest of all fossil fuels. Plentiful supply, competitive cost, and versatility continue to support an upward trend in the consumption of natural gas on a worldwide scale. In addition to its traditional industrial and residential uses, natural gas has made inroads as a motor fuel for fleet and private vehicles, and as a supply for gas-fired cogeneration power plants and for use in fuel cells.

Increasingly, gas fields are being discovered in the remotest regions of the world. Gas transportation and distribution to and within the industrial and/or populated areas where it is needed is a significant factor in its development as an energy resource. Over long distances, gas can be transported by pipelines or in liquid form in ships. For local distribution, the gas can be delivered through piping distribution networks or in trucks in liquid form.

This chapter addresses the transport and distribution of gas by pipelines and piping systems. Throughout the chapter, reference will be made to Section B31.8 of the American Society of Mechanical Engineers (ASME) Code for Pressure Piping, Gas Transmission and Distribution Piping Systems. This is for convenience only as it is beyond the scope of this endeavor to reference, cross-reference, or compare the many excellent codes and standards that have been developed and that are in use in other countries.

Definitions

Section B31.8 of the ASME Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, defines *gas* as follows:

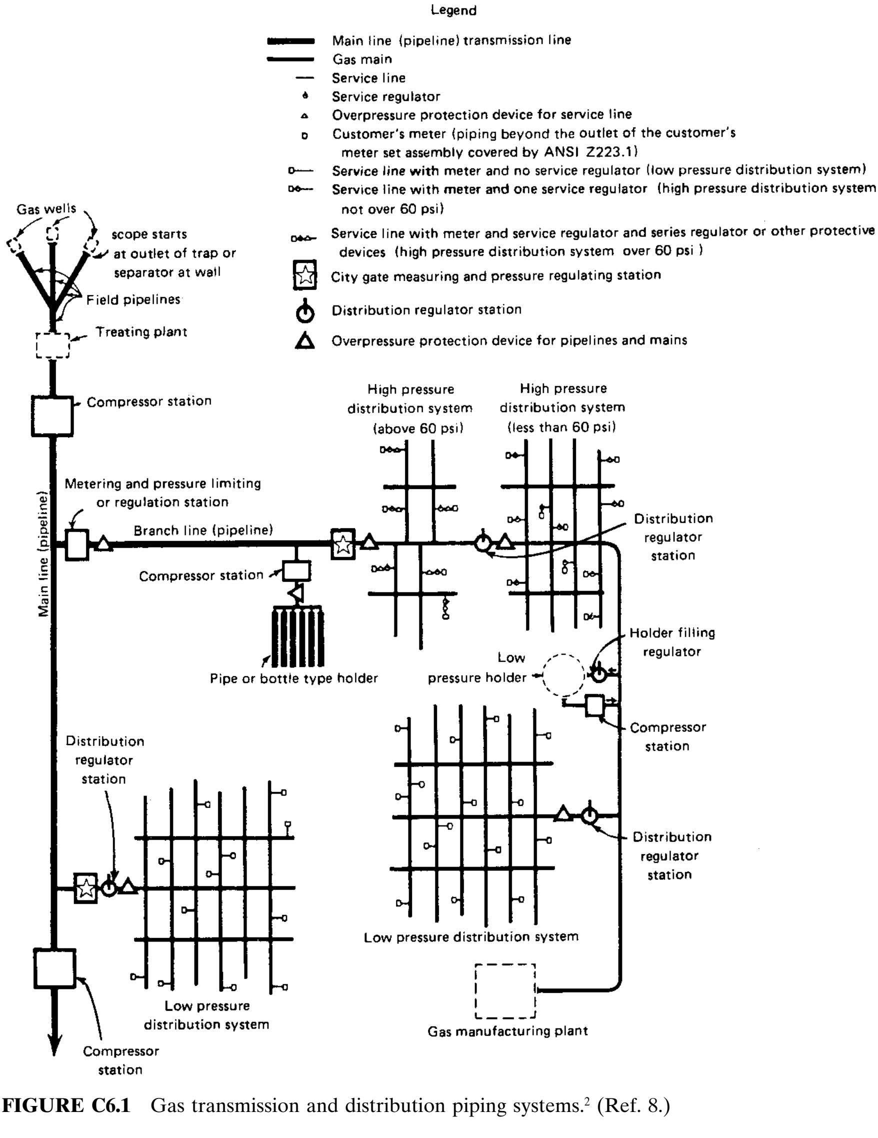


FIGURE C6.1 Gas transmission and distribution piping systems.[2] (Ref. 8.)

Gas, as used in this Code, is any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air. (Ref. 8.)

A comprehensive listing of the definitions of general terms used in the gas transmission industry is provided in Secs. 803 through 806 of ASME B31.8.

Types of Systems

Figure C6.1, abstracted from ASME B31.8, gives an overview of the piping and facilities (indicated by solid lines) considered to be part of gas transmission and distribution piping systems.

Gas Gathering System. The gas gathering system consists of field pipelines transporting dry or wet gas from the wellheads to a central treating facility, where initial separation of gas and liquids takes place.

Mainline (Pipeline) Transmission Lines. Main transmission pipelines transport gas from a source or sources of supply to one or more distribution centers or to one or more large-volume customers, or may interconnect sources of supply. Main transmission pipelines are usually characterized by larger-diameter pipe installed over longer distances with intermediate compressor stations.

Gas Distribution System. The gas distribution system is a piping system installed within a community to convey gas to individual service lines or other gas mains.

REFERENCE DOCUMENTS

Codes and Standards

In the United States as well as many other countries the need for a national code for pressure piping became evident in the early stages of the pipeline industry. To meet this need, codes and standards were developed, and reviewed and revised over the years as needed, to meet the requisites of the industry and of government regulatory agencies. The process is ongoing.

In some instances the codes and standards have become law, as is the case with The Pipeline Safety Act in the United States in the form of Title 49 Part 192 and 195 of the Code of Federal Regulations, ''Transportation of Natural and Other Gas by Pipeline'' and ''Transportation of Liquids by Pipeline.''

Needless to say, whether enacted into law or not, it is not the intent of codes and standards to provide a set of rigid rules and formulas, which if followed diligently, will always result in the design and construction of a perfect pipeline system. The great number of variables involved, the unknown circumstances that can be encountered, and the random eventualities which may occur preclude such an approach. Codes and standards do, however, provide a framework within which the experienced and competent designer or engineer can develop a safe, reliable, and economic pipeline.

The following is a listing of codes and standards referenced in this chapter:

API 5L	Line Pipe
API 1104	Welding of Pipelines and Related Facilities
API RP 520	Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries

TABLE C6.1 Gas Pipeline Code Comparison for Various Countries

Country/code	Location	Safety factor	Percent of yield	Design on min. or nom. wall thickness	Allowance for excess pressure	Main line valve frequency	Normal temperature range	Special remarks
U.S.A. ASME B31.8 1995	Class 1 Div 1 Class 1 Div 2 Class 2 Class 3 Class 4	1.25 1.4 1.7 2.0 2.5	80 72 60 50 40	Nominal	Lesser of 10% overpressure or 75% of yield	Class 1 20 miles Class 2 15 miles Class 3 10 miles Class 4 5 miles	−20°F to 450°F (−29°C to 232°C) Derating above 250°F (121°C)	Class 1: Desert or farmland Class 2: Town outskirts Class 3: Residential and commercial Class 4: Town center, high rises
CANADA-CSA Z662	Class 1 Class 2 Class 3 Class 4	1.4 1.7 2.0 2.5	72 60 50 40	Nominal	Lesser of 10% overpressure or 75% of yield	Class 1 Not Required Class 2 25 km Class 3 13 km Class 4 8 km	−100°F to 450°F (−74°C to 232°C) Derating above 250°F (121°C)	Class 1: <10 dwellings for human occupancy Class 2: >10 <46 dwellings Class 3: >46 dwellings Class 4: Buildings 4 or more stories
AUSTRALIA-AS 2885	Class R1 Class R2 Class T1 Class T2	1.4 1.4 1.7 2.0	72 72 60 50	Nominal	10% Overpressure	Class R1 As Required Class R2 30 km Class T1 15 km Class T2 15 km	−22°F to 446°F (−30°C to 230°C) Derating above 248°F (120°C)	Class R1: Undeveloped, sparsely populated Class R2: Small farms, rural residential Class T1: Residential, commercial, industrial areas Class T2: Buildings 4 or more floors Submarine lines S.F. 1.4 except at piers, risers, scraper traps S.F.: 1.7. Station piping and on bridges S.F. 1.7.
ISO/DIS 13623	Class 1 Class 2 Class 3 Class 4 Class 5	1.2 1.3 1.5 1.8 2.25	83 77 67 55 45	Minimum	None	At beginning and end of pipelines, and as needed.		Class 1: Areas of infrequent human activity Class 2: Population density <50 persons/sq km Class 3: Population density ≥50 <250/sq km Class 4: Population density ≥250/sq km Class 5: Buildings 4 or more stories

ANSI/AWWA C151/A21.51	Ductile-Iron Pipe, Centrifugally Cast, for Water
ASME 16.5	Pipe Flanges and Flanged Fittings
ASME B31.8	Gas Transmission and Distribution Piping Systems
ASME	Boiler and Pressure Vessel Code
ASTM D 2513	Thermoplastic Gas Pressure Pipe, Tubing, and Fittings
ASTM D 2517	Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
DOT 49 PT 192/195	Transportation of Natural and Other Gas by Pipeline/Transportation of Liquids by Pipeline
NFPA 30	Flammable and Combustible Liquids Code

Other Reference Documents

Many countries other than the United States have pipeline regulations of their own, and in many cases these are more stringent than the U.S. codes, especially where licensing and leak testing are concerned. These must always be researched before starting design intended for the installation of pipelines in other countries. Countries known to have codes include:

Algeria
Austria
Australia
Belgium
Canada
France
Germany
Great Britain
Japan
Italy
Russia

Table C6.1 provides a synopsis of *some* of these pipeline codes.

DESIGN

The specific identification of types of pipe generally used for high-pressure gas lines is given in the latest edition of the ASME Code for Pressure Piping, ASME B31.8. Special fittings for gas systems, together with typical details and design recommendations, are included in this chapter.

Basic Flow Equations

Rational Gas Flow Formula. Many equations for calculations involving isothermal gas flow in horizontal gas pipelines have been used by the pipeline industry with varying degrees of success over the years. One of the more common is the rational gas flow formula:

$$P_1^2 - P_2^2 = Bf(ZTGQ^2/D^5)L \qquad \text{(C6.1)}$$

where

		Units	
		Imperial	*Metric*
$B =$	dimensional constant	76.86	5608
$D =$	internal diameter	in	mm
$f =$	friction factor	dimensionless	
$L =$	length	mi	km
$G =$	gas gravity	(air = 1)	
$P_1 =$	initial line pressure	psia	kg/cm^2
$P_2 =$	final line pressure	psia	kg/cm^2
$Q =$	flow rate	1000 ft^3/hr (MCF/hr)	m^3/hr
$T =$	absolute gas temperature	°R (°F+460)	K (°C+273)
$Z =$	compressibility factor, at average flow conditions	dimensionless	

To take into account differences in elevation, the pressure profile for flow in gas pipelines is determined using the rational gas flow formula modified with J. William Ferguson's elevation correction method as follows:

$$P_1^2 - e^S P_2^2 = Bf\,(ZTGQ^2/D^5)L_e \qquad \text{(C6.2)}$$

where

		Units	
		Imperial	*Metric*
$B =$	dimensional constant	76.86	5608
$P_1 =$	initial line pressure	psia	kg/cm^2
$P_2 =$	final line pressure	psia	kg/cm^2
$e =$	natural logarithmic	base, 2.71828	
$f =$	friction factor	dimensionless	
$G =$	gas gravity	(air = 1)	

T =	absolute gas temperature	°R	K
Q =	flow rate	1000 ft^3/hr (MCF/hr)	m^3/hr
Z =	compressibility factor, at average flow conditions	dimensionless	
L =	length of pipe segment	mi	km
H =	elevation difference over the segment (positive uphill, negative downhill)	ft	m
A =	dimensional constant	26.647	14.637
s =	GH/(ATZ)	dimensionless	
L_e =	effective length $(e^s - 1)$ L/s	mi	km
D =	pipe internal diameter	in	mm
e^s =	elevation correction factor	dimensionless	

Pipe Design Formula. The design pressure for steel gas piping systems or the nominal wall thickness for a given design pressure is determined by the following formula:

$$P = 2StFET/D \tag{C6.3}$$

where

		Units	
		Imperial	*Metric*
P =	permissible design pressure	psig	kg/cm^2
S =	yield strength	psig	kg/cm^2
D =	nominal outside pipe diameter	in	mm
t =	nominal pipe wall thickness	in	mm
F =	design factor. Value depends on location class. (See Table C6.2). Exceptions are given in Table C6.3.	dimensionless	
E =	longitudinal pipe joint factor. This is a function of the type of pipe manufacture. (See Table C6.4).	dimensionless	

$T =$	temperature derating factor. (See Table C6.5)	dimensionless

Location Classes for Design. The possibility of damage to a gas pipeline increases with greater concentrations of people and buildings. One method of providing added protection is to lower the pipe stress level as a function of public activity.

TABLE C6.2 Basic Design Factor F (Ref. 8)

Location class	Design factor F
Location Class 1, Division 1	0.80
Location Class 1, Division 2	0.72
Location Class 2	0.60
Location Class 3	0.50
Location Class 4	0.40

ASME B31.8 quantifies this activity by determining location class and relating the design of the pipeline to the appropriate design factor.

ASME B31.8 has defined *location classes* as follows:

Location Class 1. A Location Class 1 is any 1 mile section that has 10 or fewer buildings intended for human occupancy. A Location Class 1 is intended to reflect areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.

Division 1. A Class 1 location where the design factor of the pipe is greater than 0.72, but equal to or less than 0.80, and which has been hydrostatically tested to 1.25 times the maximum operating pressure.

Division 2. A Class 1 location where the design factor of the pipe is equal to or less than 0.72, and which has been tested to 1.1 times the maximum operating pressure.

Location Class 2. A Location Class 2 is any 1 mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. A Location Class 2 is intended to reflect areas where the degree of population is intermediate between Location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates, etc.

Location Class 3. A Location Class 3 is any 1 mile section that has 46 or more buildings intended for human occupancy except when a Location Class 4 prevails. A Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.

Location Class 4. Location Class 4 includes areas where multistory buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multistory means 4 or more floors above ground including the first or ground floor.

The design factor for pipelines or mains supported by railroad, vehicular, pedestrian, or pipeline bridges must be determined in accordance with the location class

TABLE C6.3 Design Factors for Steel Pipe Construction (Ref. 8)

Facility	Location class 1 Div. 1	Location class 1 Div. 2	2	3	4
Pipelines, mains, and service lines	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.70	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets, with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2	0.50	0.50	0.50	0.50	0.40

TABLE C6.4 Longitudinal Joint Factor E (Ref. 8)

Spec. No.	Pipe class	E factor	Spec No.	Pipe class	E factor
ASTM A 53	Seamless	1.00	ASTM A 671	Electrical fusion welded	
	Electrical resistance welded	1.00		Classes 13, 23, 33, 43, 53	0.80
	Furnace butt welded—Continuous weld	0.60		Classes 12, 22, 32, 42, 52	1.00
ASTM A 106	Seamless	1.00	ASTM A 672	Electric fusion welded	
ASTM A 134	Electric fusion arc welded	0.80		Classes 13, 23, 33, 43, 53	0.80
ASTM A 135	Electric resistance welded	1.00		Classes 12, 22, 32, 42, 52	1.00
ASTM A 139	Electric fusion welded	0.80			
ASTM A 211	Spiral welded steel pipe	0.80	API 5L	Seamless	1.00
ASTM A 333	Seamless	1.00		Electric resistance welded	1.00
	Electric resistance welded	1.00		Electric flash welded	1.00
ASTM A 381	Double submerged-Arc-welded	1.00		Furnace butt welded	0.60
				Submerged arc welded	1.00

General note:
Definitions for the various classes of welded pipe are given in ASME B31.8.

TABLE C6.5 Temperature Derating Factor T for Steel Pipe (Ref. 2)

Temperature		Temperature derating factor T
°F	°C	
250 or less	121 or less	1.000
300	149	0.967
350	177	0.033
400	204	0.900
450	232	0.867
General note: For intermediate temperatures, interpolate for derating factor.		

prescribed for the area in which the bridge is located, except that in Location Class 1, a design factor of 0.6 must be used.

Flowing Temperature. The original equation developed to predict with reasonable accuracy the temperature of gas at any point along a transmission line was derived by Charles E. Schorre and presented in 1954 (Schorre, C.E., "Flow Temperature in a Gas Pipeline," *OGJ*, Sept. 27, 1954).

However, with Schorre's equation, flowing gas temperatures continuously decrease with downstream distance, never reaching an equilibrium value as would be expected when the Joule-Thompson cooling effect is offset by heat gain from warmer surrounding soil.

In 1979, D.M. Coulter and M.F. Bardon developed the following equation which gives a logarithmically decreasing flowing gas temperature which asymptotically approaches a value below that of the ground temperature. Using the same nomenclature as Schorre (and P = pressure):

$$T_2 = (T_1 - (T_g + (\mu/a)(dP/dX)))\, e^{(-aX)} + (T_g + (\mu/a)(dP/dX)) \quad \text{(C6.4)}$$

where

		Units: Imperial	Units: Metric
μ =	Joule-Thompson coefficient	°F/psi	$°C/kg/cm^2$
$\mu(dP/dX) = J$ =	Joule-Thompson effect	°F/ft of pipe	°C/m of pipe
X_1 =	distance to T_1 from initial point	ft	m
X_2 =	distance to T_2 from initial point	ft	m
X =	$X_2 - X_1$	ft	m
J/a =	temperature difference between the ground and gas which would be necessary to hold the gas temperature constant	°F	°C

T_1 =	initial gas temperature at point X_1	°F	°C
T_2 =	gas temperature at point X_2	°F	°C
T_g =	average ground temperature	°F	°C

$$a = 2\pi RU/(qC_p) \tag{C6.5}$$

where

		Units	
		Imperial	*Metric*
π =	Pi	3.1416	3.1416
R =	pipe radius	ft	m
U =	heat-transfer coefficient	Btu/hour/°F/sq.ft.	Joules/hour/°C/cm^2
q =	gas flowing	1000 ft^3/hr (MCF/hr)	m^3/hr
C_p =	specific heat of gas at constant pressure	Btu/°F/MCF	Joules/°C/m^3

(Coulter, D.M., Bardon, M.F.,[5] "Revised equation improves flowing gas temperature prediction," *OGJ*, Feb. 26, 1979)

Transmission Factor. The transmission factor, $(1/f)^{0.5}$, is one of the most difficult values to determine. The following equations have proven to be reasonably reliable for use with the rational gas flow formula.

For laminar flow:

$$(1/f)^{0.5} = 0.5(4 \log_{10}(f^{0.5} R_e) - 0.6) \tag{C6.6}$$

For fully turbulent flow:

$$(1/f)^{0.5} = 0.5(4 \log_{10}(3.7D/k_e)) \tag{C6.7}$$

For fully turbulent flow using Colebrook's[9] equation:

$$(1/f)^{0.5} = 1.74 - 2 \,\mathrm{Log}_{10}(2\varepsilon/D + 18.7/(R_e f^{0.5})) \tag{C6.8}$$

The Colebrook equation requires an iterative procedure to solve for f.

where

		Units	
		Imperial	*Metric*
f =	friction coefficient	dimensionless	
D =	inside diameter of pipe	in	mm
ke	effective roughness	in	mm

ε =	absolute roughness	in	mm
R_e =	Reynolds number	dimensionless	

The Reynolds number for flowing gas is determined by the following:

$$R_e = C Q_b \, G P_b / (\mu D \, T_b) \tag{C6.9}$$

where

		Units	
		Imperial	*Metric*
C =	Dimensional constant	0.7099	12.3039
Q_b =	flow rate at P_b, T_b	ft^3/day	m^3/hr
G =	gas specific gravity	(Air = 1.0)	
P_b =	base pressure	psia	kg/cm^2
μ =	viscosity	centipoise	kgf s/m^2
D =	internal diameter	in	mm
T_b =	base temperature	°R	K

Compressibility Factor. The compressibility factor, Z, may be obtained from the standard gas compressibility factor chart, Fig. C6.2.

$$\text{Pseudo-reduced temperature,} \qquad T_r = T/T_c \tag{C6.10}$$

$$\text{Pseudo-reduced pressure,} \qquad P_r = P/P_c \tag{C6.11}$$

where

		Units	
		Imperial	*Metric*
T_c =	absolute pseudo-critical temperature	°R	K
P_c =	absolute pseudo-critical pressure	psia	kg/cm^2
P =	absolute pressure at which the gas exists	psia	kg/cm^2
T =	absolute temperature at which the gas exists	°R	K

Figure C6.3 provides convenient approximations for determining the pseudo-critical pressure and pseudo-critical temperature of gases when only the specific gravity of the gas is known. Otherwise, these values should be calculated based on actual gas composition.

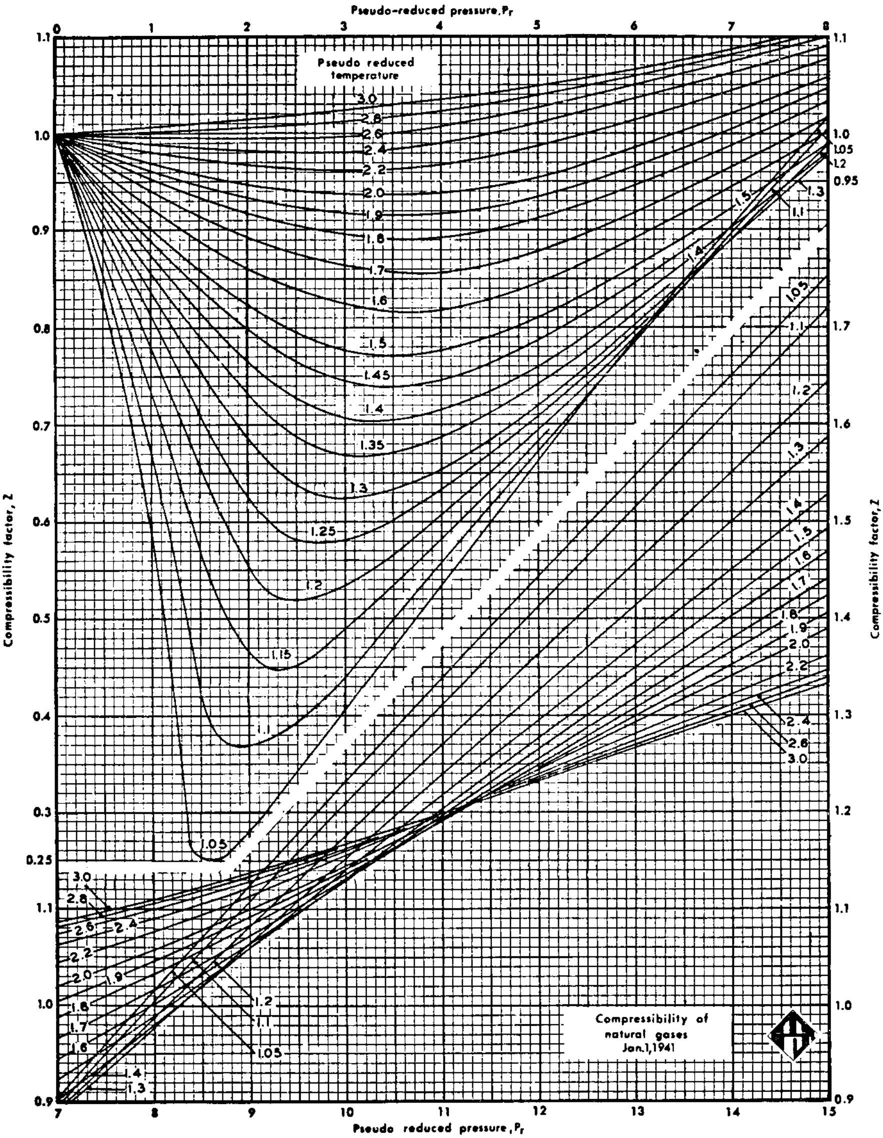


FIGURE C6.2 Compressibility factors for natural gas. *(Gas Processor Suppliers Association Engineering Data Book.)*

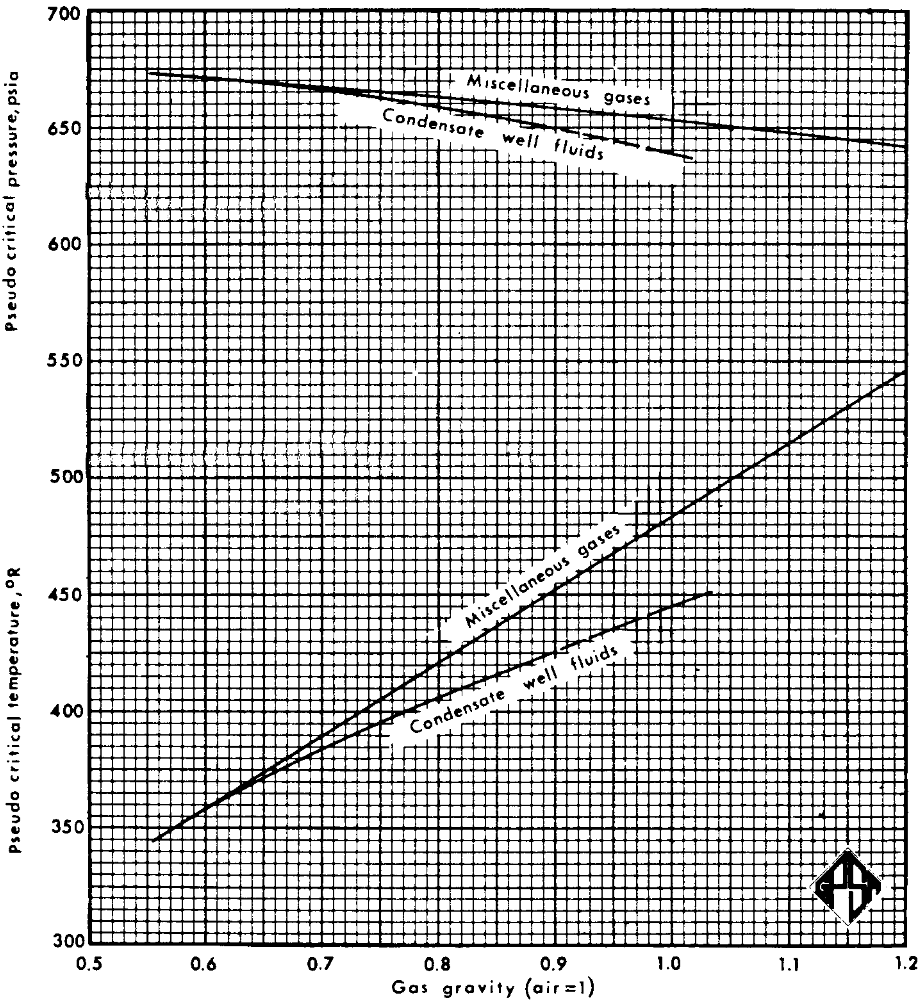


FIGURE C6.3 Pseudocritical properties of natural gases. *(Gas Processors Suppliers Association Engineering Data Book.)*

Gas Gathering Systems

Condensate Formation. Liquids are created in gas pipelines when the temperature of the gas flowing through the pipeline drops below the dewpoint of the gas. As the gas has both a hydrocarbon dewpoint and a water dewpoint, both hydrocarbons and water may condense and accumulate at low points in the pipeline to obstruct the flow of gas. In addition to the reduction in the capacity of the pipeline, the arrival of large volumes of liquid at downstream gas treatment facilities can result in severe damage to equipment or, at the least, cause erratic plant operation.

Two-Phase Flow. Accurate determination of pressures along the route of a wet gas pipeline operating in two-phase flow is difficult because the flow regimes associated with two-phase flow are numerous, complex, and difficult to define. Consideration must be given to gas and liquid fluid properties, flow regimes, pressure drop, and liquid holdup.

The major complication with two-phase flow is the variety of flow patterns that can be produced in a gas-liquid system. The type of flow pattern encountered depends upon the flow rates and properties (density and viscosity) of each of the gas and liquid components, surface tension between the two phases, pipe size, and pipe configuration, and terrain. These factors have rendered the derivation of general flow correlations difficult.

New correlations for pressure loss and liquid holdup in gas/liquid pipelines are continuously being developed and are showing consistently reliable predictions for both holdup and pressure loss when compared to actual field operating data.

The very number, complexity, and application specific limitations of many of these correlations precludes the presentation and discussion of any particular correlation in this chapter. The reader is referred to current literature to obtain the latest information and formulas, and to proprietary computer software available on the market.

Hydrate Considerations. Under unfavorable conditions, the low molecular weight hydrocarbons such as methane, propane, or butane form insoluble hydrate deposits in conjunction with water molecules. These hydrate crystals, which resemble ice or wet snow, have been known to virtually plug and stop gas transmission lines.

Hydrates may also occur in equipment as a result of cooling due to pressure reduction. This can be a problem particularly in pressure-control valves and pressure regulators, which can literally freeze up.

The methods for determining the hydrate temperature/pressure are covered in detail in Sec. 15 of the Gas Processors Suppliers Association (GPSA) Engineering Data Book.

Hydrate formation can be prevented by maintaining the gas at a higher temperature, by dehydrating the gas, or by the injection of glycol or methanol. Where hydrate problems occur at pressure-control valves or other equipment, localized heating of the equipment may provide an efficient solution.

Gas Transmission Systems

Route Selection. The most logical pipeline route is a straight line between the point of supply and the point of delivery. However, in practice this tends to be the exception and not the rule. Physical terrain, soil conditions, built-up areas, population densities, and both natural and man-made obstacles together with the requirements of codes and standards will force deviations from a straight line route.

Normally, the best route from a number of alternates will be that which results in the lowest overall project cost for the life of the project, considering material and equipment, construction, and operation and maintenance costs.

In evaluating possible pipeline routes, consideration must be given to the following:

Location of Facilities. Although the locations of supply and delivery points are usually fixed, the siting of these facilities should take into account the availability of suitable pipeline routes whenever possible.

On long transmission lines, the availability of suitable sites for intermediate compressor stations will also have an impact on the selection of the final route.

And finally, the location of possible future supply and delivery connections to the mainline may play a role in the alignment of the mainline.

Environment. Impact on the environment of pipeline construction, maintenance, and operation must be considered and mitigated, or avoided altogether by rerouting. Special attention must be given to the habitats of endangered species of plant and animal life. In many instances severe restrictions will be imposed on the construction of the pipeline and related facilities.

Cultural and Historical Heritage. Sensitivity to the significance of local cultural and historical areas to the local peoples must be exercised in developing the pipeline route. Gaining the trust and respect of the people who will be affected by the installation and operation of the pipeline will reap substantial benefits for construction and future operation.

Terrain. The terrain which a pipeline traverses has a significant impact on construction costs and in some cases maintenance costs. For instance, the amount of rock along the pipeline route has a major impact on the cost of installation, but little or none on operating or maintenance costs. However, areas of soil erosion, landslide areas, swamps, and river crossings increase both the cost of installation and the cost of maintenance. Such areas usually require special construction methods and in many cases require stabilization measures after installation which become a continuing maintenance item.

Man-Made Infrastructure. The pipeline route must normally also cross roads, highways, railroads, canals, and irrigation structures. Such crossings increase the installation costs as additional depth of burial, and in some instances, the installation of casing is required. The costs of crossing such obstacles must be weighed against the costs of alternate routes, if available.

Populated Areas. The pipeline route should avoid populated areas to reduce the exposure of the population to hazards associated with the pipeline. Also, by avoiding populated areas, the possibility of damage to or interference with the pipeline is reduced.

There is also an economic penalty in crossing populated areas. Most codes will require the use of a lower pipe design factor, resulting in the installation of heavier-wall pipe. More expensive construction methods may also be required and ready access to the pipeline for operation and maintenance may be reduced.

The area defined by Section 840 of ASME B31.8 in which the design of the pipeline is affected by the density of the population extends 200 meters (⅛ mile) on either side of the pipeline. As future increases in population density can force the upgrading of an existing pipeline, the rate of development and probable direction of future population growth must be considered in selecting the pipeline route.

Diameter Selection/Station Spacing. Investment in pipe invariably represents the largest single expenditure for a transmission line. It is therefore imperative to find the size of pipe that will most cost-effectively handle the required gas volumes. To do so, horsepower and compressor station spacing must be considered. While pipe tonnage represents a high first cost in investment compared to the installation of horsepower, the operating charges for pipe are relatively negligible, while fuel and maintenance costs of compressor facilities are high. The savings realized by decreasing pipe tonnage can eventually be offset by the costs associated with the increased horsepower required.

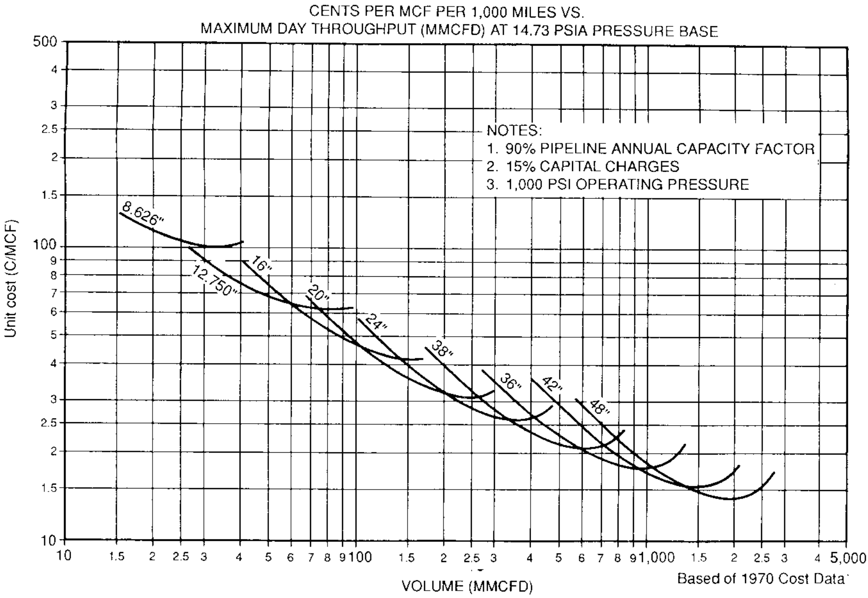


FIGURE C6.4 Effect of pipeline diameter on gas transmission costs.

An estimate of the pipe size required can be made from charts similar to Fig. C6.4, which plot gas transmission costs against throughput volume for varying pipe diameters. With the approximate pipe size(s) determined, a preliminary economic analysis can be performed using computer programs developed for economic studies of gas pipeline systems. These programs allow for the rapid comparison of a number of alternatives, allowing the selection of the one apparently offering most economic advantages.

With an optimum pipe size determined, a more precise design of the selected system can be undertaken.

Mainline Valves. Mainline valves are installed in gas transmission lines for both safety and economic reasons. The basic concern is the loss of gas and the associated hazards in the event of a break in the pipe. Factors which must be considered in determining the spacing of mainline valves include:

- The availability of continuous access to the valves
- The conservation of gas
- The time required to blow down any given section of pipe in case of emergency or maintenance
- Continuity of gas service
- Operating flexibility
- Future development within the pipe section
- Any significant natural conditions which could adversely affect the operation and security of the pipeline

The maximum spacing between valves is specified in Sec. 846 of ASME B31.8 and varies with the population density along the pipeline. Spacing on new transmission lines may not exceed the following:

Location	*Spacing*
Class 1	20 miles (32 km)
Class 2	15 mile (24 km)
Class 3	10 miles (16 km)
Class 4	5 miles (8 km)

The mainline valves should be of the full-opening, through-conduit type to allow for the passage of scrapers and inspection pigs. Either ball or gate valves are suitable, preferably weld-end (avoids flange leaks) with shop-welded transition pieces. Valves for underground service should have stem extensions to elevate the valve operators above grade and should also have lubricant and bleed lines extended for ease of access.

Blowdown Assemblies. Blowdown assemblies allow for the evacuation of gas from sections of pipeline under emergency conditions or for scheduled maintenance operations. A typical mainline valve and blowdown assembly is shown in Fig. C6.5.

The primary consideration in sizing the piping for the assembly is the time required to blow down the section between two mainline valves.

The following formula, found in the American Gas Association Manual, provides a means of determining venting time and blowdown valve size:

$$T_m = B P_1^{1/3} G^{1/2} D^2 L F_c / d^2 \tag{C6.12}$$

where

		Units	
		Imperial	*Metric*
T_m =	blowdown time	min	min
B =	dimensional constant	0.0588	0.0886
P_1 =	initial line pressure, abs	psia	kg/cm^2
G =	specific gravity	(Air = 1.0)	
D =	inside diameter of pipe	in	mm
L =	length of pipeline section	mi	km
d =	inside diameter of blowdown	in	mm
F_c =	choke factor: ideal nozzle = 1.0 through gate = 1.6 regular gate = 1.8 regular lube plug = 2.0 venturi lube plug = 3.2		

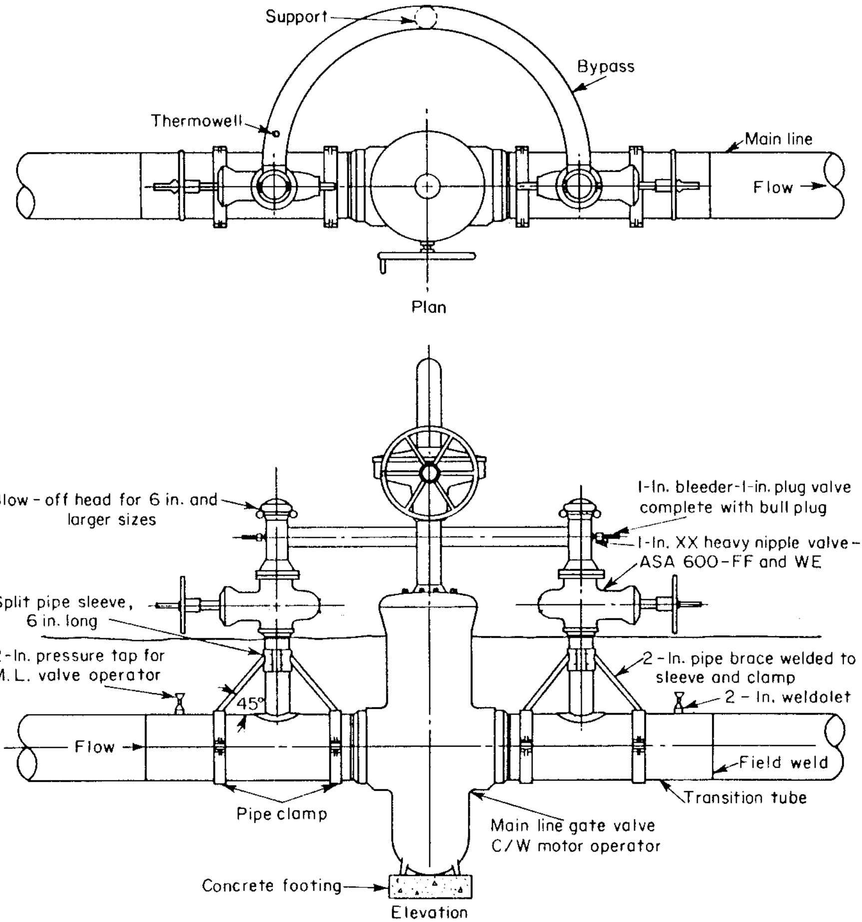


FIGURE C6.5 Mainline gate valve equipped with bypass and blowoff arrangement. *(Piping Handbook, fifth edition.)*

Supports for the blowdown assembly must be designed to not only carry the weight of valves and piping but also the thrust loads which will occur during venting.

Gas Distribution Systems

Although the service pipe that connects the street main to the customer's meter is usually installed by the gas supplying company, the actual ownership (and hence, responsibility) of the pipe varies. In some areas, the gas company owns the pipe all the way to the meter set assembly, but in others the customer owns the pipe from the property line.

Sizing of services may be facilitated by reference to published tables and charts,

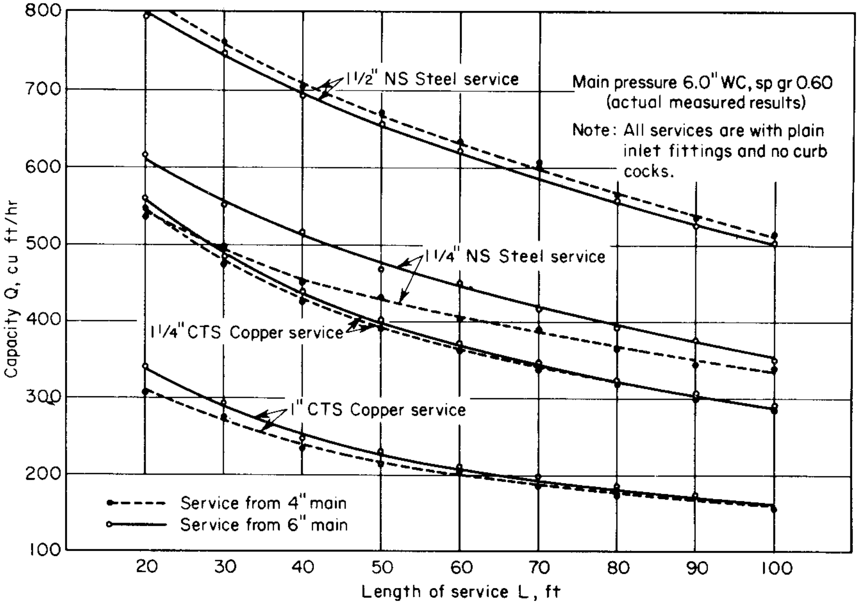


FIGURE C6.6 Total gas flow through LP services, 0.5 in (12.7 mm) water column total drop.

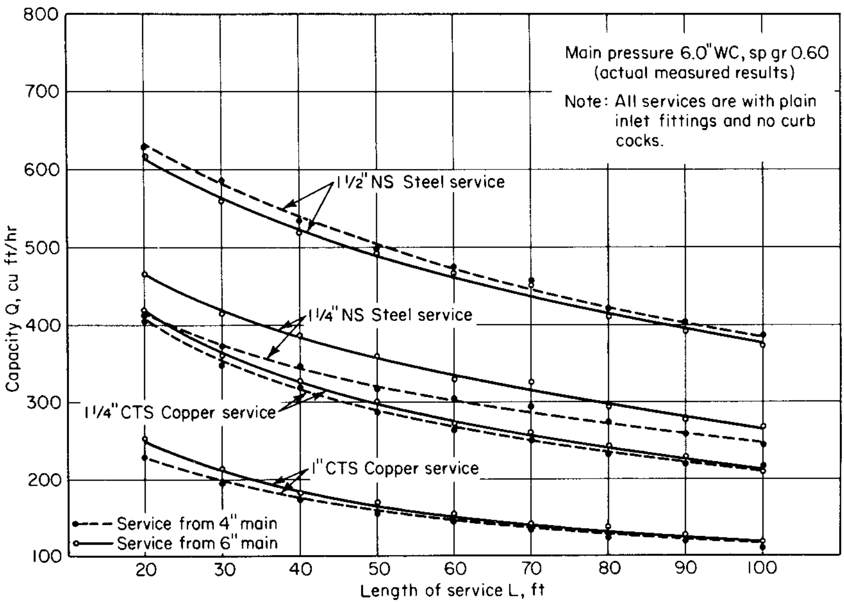


FIGURE C6.7 Total gas flow through LP services, 0.3 in (7.6 mm) water column total drop.

or now, more than likely through the use of either proprietary gas company or marketed computer software. Regardless of the tools used, the following discussion still provides an overview of the thought processes involved, and the charts and tables allow for a simplified means of determining pressure drop and flow rate.

Many different bases are available and used in selecting the proper size. Some use a maximum pressure drop; some use a maximum size for all services; others make a detailed pressure drop calculation for each installation. A brief description of the methods followed by a majority of the companies will be of interest. Consideration of connected load, length of service, and main pressure are made in selecting service pipe size. Generally this combination of variables is handled by means of selecting an allowable pressure drop for a particular main pressure and then selecting the pipe size based upon length of service and anticipated load, which will result in a calculated pressure drop of less than the allowable. Since it is usually the easiest to determine the connected load on a gas service, this flow is used to size the service pipe. Some companies refine the principle by introducing a diversity factor based upon the assumption that all of the appliances will not be in use at the same time. Others assume that the service will ultimately supply a piece of gas space heating equipment and size the service for this load even if no house heating load is installed at present.

The pressure drop allowed on a gas service is primarily a function of the pressure being carried on the mains during the time the mains are supplying the peak demand. In a low-pressure system which operates at a nominal main pressure of from 6 to 8 in (152.4 to 203.2 mm) of water column, most of the companies consider the maximum allowable pressure drop on a gas service to be either 0.3 or 0.5 in (7.6 or 12.7 mm) of water column (see Figs. C6.6 and C6.7). An intermediate-pressure system operating at a main pressure of from 1 to 15 psig (0.07 to 1.05 kg/cm^2) will generally permit an allowable pressure drop of about 0.5 psig (0.035 kg/cm^2). High-pressure distribution systems permit allowable pressure drops of 0.5 to 3 psig (0.035 to 0.21 kg/cm^2). Another method of selecting the allowable pressure drop is to specify that it be some percentage of the main pressure during the maximum hour. One company selects a 20 percent drop, and another a 10 percent drop. Still another method is to specify a value of 10 for the difference in squares of the absolute inlet and outlet pressures.

Flow Characteristics of Low-Pressure Services. Experiments in 1960 showed that the widely used Spitzglass equation for low-pressure gas flow required new resistance values. This flow is a function of inside diameter rather than surface smoothness. Thus, tubing of smaller diameter does not have a capacity equal to that of a larger steel pipe through which it may be drawn for replacement purposes.

The flow equation for either copper or steel services from ¾ in copper tubing size (CTS) copper to NPS 1½ (DN 40) steel pipe was found to follow the form:

$$Q = C\left[\frac{\text{total pressure drop in service, } P}{(K_p)(S/S')(L+L_{ef})}\right]^{0.54} \tag{C6.13}$$

			Units	
			Imperial	*Metric*
where	$Q =$	flow	ft^3/h	m^3/h

C =	dimensional constant	1	0.009012
P =	total pressure drop in service	in H_2O	cm H_2O
K_p =	pipe constant, Table C6.6	dimensionless	
S =	sp gr of gas	dimensionless	
S' =	sp gr 0.60	dimensionless	
L =	length of service	ft	m
L_{ef} =	equivalent length of fittings, Table C6.7	ft	m

TABLE C6.6 Values of K_p

CTS ¾ (DN 20) copper	1.622×10^{-6}
NPS 1 (DN 25) plastic	0.279×10^{-6}
CTS 1 (DN 25) copper	0.383×10^{-6}
CTS 1¼ (DN 32) copper	0.124×10^{-6}
NPS 1¼ (DN 32) steel	0.080×10^{-6}
NPS 1½ (DN 40) steel	0.037×10^{-6}

TABLE C6.7 Equivalent Length of Fittings

	Feet	Meters
CTS 1 (DN 25) or CTS 1¼ (DN 32) curb cock for copper service	3.5	1.07
NPS 1¼ (DN 32) curb cock for steel service	13.5	4.11
1½-in (DN 40) curb cock for 1½-in (DN 40) steel service	12.0	3.66
NPS 1¼ (DN 32) street elbow for steel service	7.5	2.29
NPS 1½ (DN 40) street elbow for steel service	7.5	2.29
NPS 1¼ (DN 32) street tee for steel service	10.5	3.20
NPS 1½ (DN 40) street tee on sleeve or NPS 1¼ (DN 32) hole in main	15.0	4.57
NPS 1¼ × 1 × 1¼ (DN 32 × 25 × 32) street tee	23.0	7.01
NPS 1½ × 1¼ × 1½ (DN 40 × 32 × 40) street tee	19.0	5.79
Combined outlet fittings:		
CTS ¾ (DN 20) copper	2.0	0.61
CTS 1 (DN 25) copper or plastic	6.0	1.83
NPS 1¼ (DN 32) steel	8.0	2.44
NPS 1½ (DN 40) steel	22.0	6.71

PIPE AND FITTINGS

Primary Materials

Most pipe for transmission pipelines worldwide is made to American Petroleum Institute (API) Specification 5L, Specification for Line Pipe, and virtually all the major pipe mills in the world qualify for the API stamp. The API specification covers:

- Pipe made from mild steel, Grades A and B (specified minimum yield strengths up to 35,000 psi)
- Pipe made from high-strength steels (i.e., X42, X46, X52 etc., the number following the "X" being the specified minimum yield strength expressed in thousands of psi)
- Pipe made by welding coiled skelp into a helix (spiral) and welding the abutted edges

Refer to App. E5 and App. E6.

Line pipe comes in a variety of sizes from NPS 3 to NPS 60 (DN 80 to DN 1500) in outside diameter. Special production runs of pipe up to NPS 100 (DN 2500) in diameter have been made. Wall thickness is usually specified in 1⁄32 in (0.8 mm) in intervals, from 3⁄16 in in small pipe sizes to 1¼ in (31.75 mm) in the larger diameters. American engineers use the decimal equivalent of 1⁄32 in to express wall thickness (.219 for 7⁄32 in, .250 for ¼ in, etc.). Engineers in metric countries express the same wall thickness in millimeters (.219 in = 5.56 mm, .250 in = 6.35 mm, etc.). Pipe sizes in the metric system tend to be expressed in multiples of 25 mm nominal (NPS 14 = DN 350, NPS 24 = DN 600, etc.). Refer to Chap. A1.

Pipe flanges and flanged fittings are manufactured according to the American Society of Mechanical Engineers Standard, ASME B16.5, Steel Pipe Flanges and Flanged Fittings, which establishes pressure ratings for eight classes of flanges and fittings. ASME B16.5 details the standard physical dimensions, number and size of bolt holes, etc. for each size fitting. The exact pressure rating of each class of fitting varies with type of steel and the design temperature.

Other Materials

Other materials which have been used in gas service include ductile-iron, plastic, and copper. Cast-iron, because of its brittleness, is quickly being replaced by plastic pipe. These are generally limited to use in mains and service lines in distribution systems. A brief summary of the limitations and restrictions on their use is given below.

Ductile-Iron. Ductile-iron pipe must be manufactured in accordance with ANSI A21.51/AWWA C151 Ductile Iron Pipe, Centrifugally Cast, in Metal Molds or Sand Lined Molds for Gas.

Plastic. Plastic pipe and components must be manufactured in accordance with the following American Society for Testing and Materials (ASTM) standards:

ASTM D 2513	Thermoplastic Gas Pressure Pipe, Tubing, and Fittings
ASTM D 2517	Reinforced Epoxy Resin Gas Pressure Pipe and Fittings

Copper. Copper tubing or pipe for use in gas mains is limited to pressures of 100 psi (7 kg/cm^2) or less, must have a minimum wall thickness of 0.065 in (1.65 mm), and must be hard-drawn.

Where the gas being transported contains more than an average of 0.3 grains of hydrogen sulfide per 100 standard cubic feet (2.83 standard cubic meters) of gas, copper may not be used.

COMPRESSOR STATIONS

Types and Function

The compressor station is the equivalent of the pump station on a liquid transportation pipeline system. Whenever a gas has insufficient energy for transport, a compressor station is installed. The types of compressor stations that are in general use can be categorized as follows:

Field or Gathering Stations. These stations gather gas from wells in which pressure is not sufficient to produce a desired flow rate into transmission or distribution systems. Such stations may handle suction pressures from below atmospheric pressure up to 750 psig (53 kg/cm^2), and volumes from a few thousand to many million standard cubic feet (30 to 30,000 m^3) per day.

Repressurizing or Recycling Stations. This type of station is an integral part of a processing or secondary recovery facility, which may or may not involve transportation of natural gas to a consumer. All or a percentage of the gas is reinjected into the reservoir for reservoir maintenance, or for storage for future use. Discharge pressures can exceed 6000 psig (420 kg/cm^2).

Storage Field Stations. These stations compress trunk line gas for injection into designated storage wells. Discharge pressures may range up to 4000 psig (280 kg/cm^2) with compression ratios as high as 1 to 4. Some storage stations are designed to also permit the withdrawal of gas from storage as well, and to inject the gas into high-pressure pipe lines. These field stations require precise design engineering due to the wide range of pressure-volume operating conditions encountered.

Distribution Plant Stations. Distribution plant stations compress gas from a holder supply to medium- or high-pressure distribution lines at about 20 to 100 psig (1.4 to 7 kg/cm^2), or compress gas into bottle storage at pressures up to 2500 psig (175 kg/cm^2).

Pipeline Booster Stations. Stations of this type are used in gas transmission line service. The volume through these stations is usually quite large with compression ratios below 2. The pressure range is generally between 200 and 1000 psig (14 and 70 kg/cm^2), sometimes as high as 1200 psig (84 kg/cm^2). However, this upper limit is continuously being challenged and gas transmission systems with an ASME Class 900 pressure rating (150 kg/cm^2/2160 psi) are being considered.

Compressor Station Layout

A typical compressor station arrangement can be broken down into three principal systems:

- Main Gas System
- Unit Gas System
- Auxiliary Gas System

Main Gas System. The main gas system includes the main gas piping and equipment between the transmission pipeline and the compressor unit suction and discharge leads. Equipment encompasses:

- Station Block Valves
- Station Bypass Valve
- Station Purge Valve
- Gas Scrubbers
- Orifice Fitting
- Station Surge Valve
- Station Relief Valves
- Station Blowdown Valve

Unit Gas System. The unit gas system includes the suction and discharge leads from the main gas header to the compressor and back to the main gas header. Equipment basically consists of:

- Unit Block Valves
- Unit Bypass Valve
- Unit Purge Valve
- Unit Vent Valve

Auxiliary Gas System. The auxiliary gas system supplies the gas needed for compressor start-up and operation and for other facilities (such as power generation and valve actuation) within the compressor station which require gas. The subsystems include:

- Fuel Gas System
- Starting Gas System
- Utility Gas System

Gas enters the station through the station block valve, passes through the scrubber, orifice meter, and unit suction block valve to the compressors where it is compressed, and is then discharged through a unit discharge block valve to the station discharge piping and block valve back to the transmission line.

Piping

In the United States, compressor station piping design is governed by the minimum requirements of the Federal Safety Standard "DOT Title 49 Part 192 Transportation of Natural and Other Gas by Pipeline."

For high-pressure transmission service, the law specifies certain types of pipe materials. According to ASME B31.8, compressor station piping must be Class 3 construction. A design factor of 0.5 (Table C6.2) must be used in the steel pipe design formula.

After possible pipe sizes are determined and preliminary station layouts are prepared, pressure-drop studies and thermal piping stress studies must follow. The thermal piping stress analysis determines that stresses in station piping in general stays within allowable limits, and that, in particular, forces and moments on compressor flanges do not exceed allowable values set by the compressor manufacturer. Pipe stresses are caused by the temperature increase when gas is being compressed. The temperature rise across a compressor can range from 0.2 to 4°F (0.1 to 2°C) per 1.5 psi (0.1 kg/cm^2) increase in pressure, depending on the specific gas and pressure involved.

Noise is defined as airborne sound energy within a broad range of frequencies that has the potential to cause either physical or psychological discomfort, or injury to personnel. In order to keep noise levels in station piping within acceptable limits (on the order of 80 decibels), the following gas velocities should not be exceeded:

- Station Main Gas Piping 40 fps (12 m/s)
- Unit Main Gas Piping 25 fps (7.5 m/s)
- Fuel Gas Piping 25 fps (7.5 m/s)

The selection of maximum allowable velocities requires an engineering study for each specific application.

In designing compressor station piping, consideration must also be given to installing piping above ground, or below ground. It should be noted that aboveground piping is easier to monitor for gas leaks and to maintain; however, station yard access may be impeded. For buried piping, the reverse applies.

An additional item often overlooked in station piping design is the installation and placement of drain connections to properly drain the water out of piping after hydrostatic testing.

Components and Equipment

Buildings. Types of compressor station buildings will vary depending on geographic location and climate, whether the station is manned or unmanned, and whether it is located in a rural or a populated area. Structures can vary from a simple shelter to provide some protection from sun and rain, to site-constructed or prefabricated buildings, to totally enclosed prepackaged units ready for installation.

Station Valves—Operators. Main station valves, normally ball, plug, or gate, are actuated by gas or electric motors for ease and speed of operation. Use of motor operators for valves is a function of the availability and cost of power. Gas actuators usually utilize the energy inherent in the pressurized gas of the main line. However, gas actuators will vent spent gas to the atmosphere, so the frequency of valve operation and the quantity of gas needed per operation must be evaluated.

Scrubbers. Gas scrubbers are installed in upstream station piping to remove any liquids or solid particles which may damage the compressors. They tend to be of two types as follows:

Horizontal Inline Type. Horizontal inline scrubbers take advantage of the effect of the helicoid tuyere. The gas, after entering the vessel, is subjected to an extended centrifugal motion which throws the heavier particles to the periphery of the vessel. Here the particles are forced into an annular space, at which point all solid particles are trapped and ejected through the drain. The inlet stream, freed from entrained particles, continues through to the outlet of the separator.

A secondary vortex breaker prevents reentrainment, thereby extending flow range. General scrubber characteristics are as follows:

Efficiency:	99.5 percent of all solids or liquids
Pressure drop:	Low
Cost:	Medium
Flow Range:	Relatively wide
Installation:	Simple and straightforward

Vertical Tube Type. In vertical tube type gas scrubbers, dust-laden gas enters the tube tangentially, creating a high centrifugal force that projects solids and liquid droplets to the walls of the tube. Clean gas reverses flow at the vortex and passes through a concentric outlet tube to an outlet plenum. Impurities continue downward to a storage area for disposal.

Flowmeters. (see Gas Metering.)

Purge, Relief, Surge, and Blowdown. (see Pressure Relief.)

OTHER FACILITIES

Pressure Relief

The following discussion on pressure-relief valves was abstracted from an article by Gary B. Emerson in the February 1987 issue of *Pipe Line Industry.*[1]

A *safety relief valve* is an essential and important piece of equipment on virtually any pressured system. Required by the ASME Boiler and Pressure Vessel Code, Sec. VIII, Pressure Vessels, among others, it must be carefully sized to pass the maximum flow produced by emergency conditions.

Sizing. The sizing formulas for vapors and gases fall into two general categories:

- Based on the flowing pressure with respect to the general categories
- Based on the flowing pressure with respect to the discharge pressure

When the ratio of P_1 (set pressure plus allowable accumulation) to P_2 (outlet pressure) is greater than two, the flow through the relief valve is sonic; the flow reaches the speed of sound for the particular flowing medium. Once the flow becomes sonic, the velocity remains constant; it cannot go supersonic. No decrease of P_2 will increase the flow rate.

Sonic Flow. In accordance with API RP 520, Part 1, Sec. 4.3.2, the formulas used for calculating orifice areas for sonic flow are:

$$A = B_w W (TZ/M)^{0.5} / CKP_1 \qquad \text{(C6.14)}$$

TABLE C6.8 Gas Constant Based on Ratio of Heats

Gas	Mol. wt.	C_p/C_v	C
Acetylene	26	1.26	343
Air	29	1.40	356
Ammonia	17	1.31	348
Argon	40	1.67	378
Benzene	78	1.12	329
Butadiene	54	1.12	324
Carbon dioxide	44	1.28	345
Carbon monoxide	28	1.40	356
Ethane	30	1.19	336
Ethylene	28	1.24	341
Freon 22	86.47	1.18	335
Helium	4	1.66	377
Hexane	86	1.06	322
Hydrogen	2	1.41	357
Hydrogen sulfide	34	1.32	349
Methane	16	1.31	348
Methyl mercapton	48.11	1.20	337
N-Butane	58	1.09	326
Natural gas (0.60)	17.4	1.27	344
Nitrogen	28	1.40	356
Oxygen	32	1.40	356
Pentane	72	1.07	323
Propane	44	1.13	330
Propylene	42	1.15	332
Sulfur dioxide	64	1.29	346

$$A = B_q Q (TZM)^{0.5} / (6.32 C K P_1) \qquad \text{(C6.15)}$$

where

		Units	
		Imperial	*Metric*
$A =$	calculated orifice area	in^2	cm^2
$B_w =$	dimensional constant	1	1.3387
$B_q =$	dimensional constant	1	21.4881
$W =$	flow capacity	lb/h	kg/h
$Q =$	flow capacity	scfm	m^3/min
$M =$	molecular weight of flowing media	dimensionless	
$T =$	inlet temperature, absolute	°F + 460	°C + 273

$Z =$	compressibility factor	dimensionless	
$C =$	gas constant based on ratio of specific heats (Table C6.8)	dimensionless	
$K =$	valve coefficient of discharge	dimensionless	
$P_1 =$	inlet pressure (set pressure + accumulation + atmospheric pressure)	psia	kg/cm^2

Subsonic Flow. The second general category for vapor or gas sizing is generally when P_2 is greater than half of P_1 (back pressure greater than half of inlet pressure).

Using k (ratio of specific heats) and P_1/P_2 (absolute), confirm from Fig. C6.8 that the subsonic ("low pressure") flow formula is required. If so, then determine F factor. If not, use sonic flow formula.

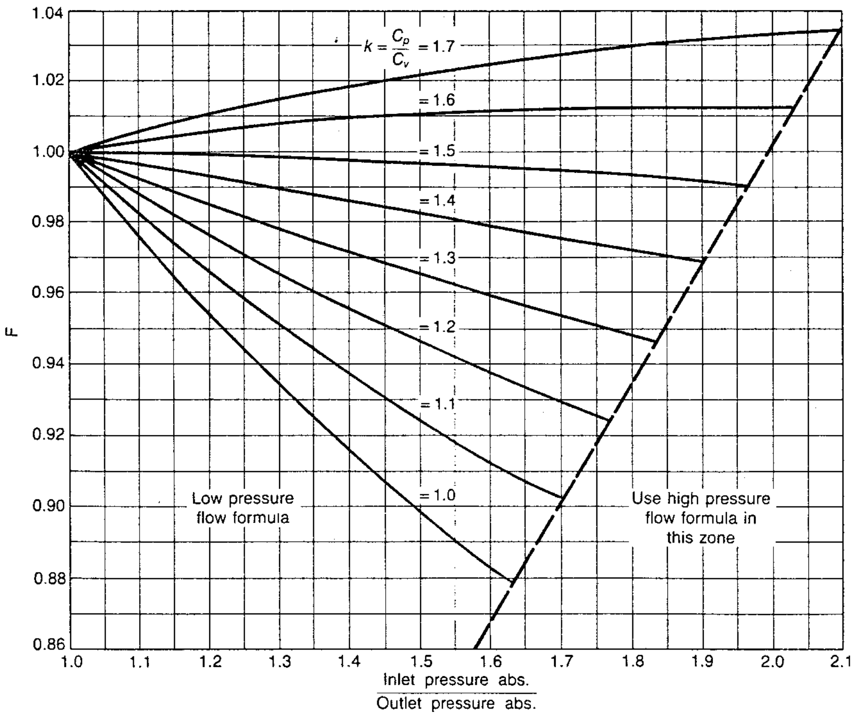


FIGURE C6.8 Low-pressure and high-pressure flow formulas.

$$A = BQ(GTZ)^{0.5}/[863KF((P_1 - P_2)P_2)^{0.5}] \qquad \text{(C6.16)}$$

where

		Units	
		Imperial	*Metric*
A =	calculated orifice area	in^2	cm^2
B =	dimensional constant	1	21.4881
Q =	flow capacity	scfm	m^3/min
G =	specific gravity	dimensionless	
T =	inlet temperature, absolute	°F + 460	°C + 273
Z =	compressibility factor	dimensionless	
F =	factor obtained from Figure C6.8	dimensionless	
K =	valve coefficient of discharge	dimensionless	
P_1 =	inlet pressure (set pressure + accumulation + atmospheric pressure)	psia	kg/cm^2
P_2 =	outlet pressure (back pressure + atmospheric pressure)	psia	kg/cm^2

After determining the calculated orifice area, select the next-largest standard orifice size from the relief valve manufacturer's catalog.

Selection. The fundamental selection of a relief valve involves the consideration of the two basic types more commonly used.

Conventional spring-loaded relief valves embody the following advantages:

- Competitively priced at lower pressures and in smaller sizes
- Wide range of chemical compatibility
- Wide range of temperature compatibility, particularly at higher temperatures

The disadvantages of conventional spring-loaded relief valves are:

- Metal-to-metal seat not tight near set pressure and usually after valve relieves
- Sensitive to conditions that can cause chatter and/or rapid cycling
- Protection against effects of back pressure is expensive, pressure limited, and creates possible additional maintenance problems
- Testing of set pressure not easily accomplished

Advantages of pilot-operated type relief valves are:

- Seat tight to set pressure (Fig. C6.9)
- Ease of setting and changing set and blowdown pressures
- Can achieve short blowdown without chatter
- Pop or modulating action available
- Easy maintenance
- Easy verification of set pressure without removing relief valve from service
- Flexible—options for remote operation, back pressure protection, valve position indication

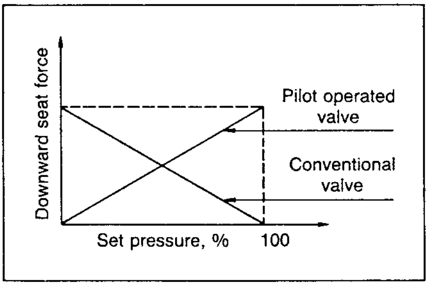


FIGURE C6.9 Setting seat pressure to set flow pressure.

The disadvantages of pilot-operated relief valves are:

- Maximum temperature limitations
- Should not be used in extremely dirty or polymerizing type service

Inlet Piping. The proper design of safety relief valve inlet piping is extremely important. Very often, safety relief valves are added to an installation at the most physically convenient location, with little regard to flow considerations. Pressure loss during flow in a pipe always occurs. Depending upon the size, geometry, and inside surface condition of the pipe, the pressure loss may be large (20, 30, or 40 percent) or small (less than 5 percent).

API RP 520, Part 2, recommends a maximum inlet pipe pressure loss to a safety relief valve of 3 percent. This pressure loss shall be the sum total of the inlet loss, line loss, and when a block valve is used, the loss through it. The loss should be calculated using the maximum rated flow through the pressure-relief valve.

The 3 percent maximum inlet loss is a commendable recommendation but often very difficult to achieve. If it cannot be achieved, then the effects of excessive inlet pressure should be known. These effects are rapid or short cycling with direct spring-operated valves or resonant chatter with pilot-operated relief valves. In addition, on pilot-operated relief valves, rapid or short cycling may occur when the pilot pressure sensing line is connected to the main valve inlet. Each of these conditions results in a loss of capacity.

Pilot-operated valves can tolerate higher inlet losses when the pilot senses the system pressure at a point not affected by inlet pipe pressure drop. However, even though the valve operates satisfactorily, reduced capacity will still occur because of inlet pipe pressure losses. The sizing procedure should consider the reduced flowing inlet pressure when required orifice area, A, is calculated.

A conservative guideline to follow is to keep the equivalent L/D ratio (length/diameter) of the inlet piping to the relief valve inlet to five or less.

Discharge Piping. Discharge piping for direct spring-operated valves is more critical than for pilot-operated valves. As with inlet piping, pressure losses occur in discharge headers with large equivalent L/D ratios. Excessive back pressure will reduce the lift of a direct spring-operated valve, and enough back pressure (15 to 25 percent of set + overpressure) will cause the valve to reclose. As soon as the valve closes, the back pressure in the discharge header decreases and the valve opens again, with the result that rapid cycling can occur.

Pilot-operated relief valves with the pilot vented to the atmosphere or with a pilot balanced for back pressure are not affected by back pressure. However, if the discharge pressure can ever exceed the inlet pressure, a back-flow preventer must be used.

The valve-relieving capacity for either direct- or pilot-operated relief valves can be affected by back pressure if the flowing pressure with respect to the discharge pressure is below critical (subsonic flow).

Balanced bellows valves (direct spring-operated) have limitations on maximum permissible back pressure due to the collapse pressure rating of the bellows element. This limitation will in some cases be less than the back pressure limit of a conventional valve. Manufacturer's literature should be consulted in every case. If the bellows valve is used for systems with superimposed back pressure, the additional built-up back pressure under relieving conditions must be added to arrive at maximum back pressure.

Satisfactory performance of pressure-relief valves, both as to operation and flow capacity, can be achieved through the following good discharge piping practices:

- Discharge piping must be at least the same size as the valve outlet connection and may be increased when necessary to larger sizes.
- Flow direction changes should be minimized, but when necessary use long-radius elbows and gradual transitions.
- If the valve has a drain port on its outlet side, it should be vented to a safe area. Avoid low spots in discharge piping; preferably pitch piping away from valve outlet to avoid liquid trap at valve outlet.
- Proper pipe supports to overcome thermal effects, static loads due to pipe weight, and stresses that may be imposed due to reactive thrust forces must be considered.

Reactive Force. On large-orifice, high-pressure valves, the reactive forces during valve relief are substantial, and external bracing may be required (see Fig. C6.10).

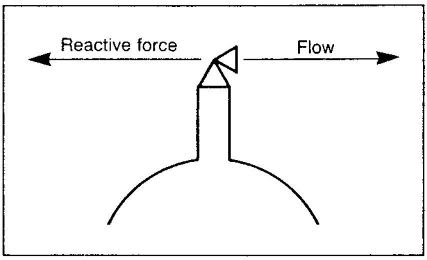


FIGURE C6.10 Reactive forces during valve relief.

API RP 520, Part 2 gives the following formula for calculating this force.

$$F = [Q_h/366][(kT/(k+1)M]^{0.5} \qquad \text{(C6.17)}$$

where

		Units	
		Imperial	*Metric*
$F =$	reactive force at valve outlet centerline	lb	kg
$Q_h =$	flow capacity	lb/h	kg/h

k =	ratio of specific heats (C_p/C_v)	dimensionless	
T =	inlet temperature, absolute	°F + 460	°C + 273
M =	molecular weight of flowing media	dimensionless	

If bracing is not feasible, a dual-outlet valve (available in some pilot-operated safety relief valves) can be used. The reactive forces are equal but opposite, resulting in zero force on the valve outlet, but if redirected can still impose loads that must be reacted to in some manner.

Testing. Using DOT Title 49, Part 192.739 as a guideline, each valve should be inspected at least once a year to determine that it:

- Is in good mechanical condition
- Will operate at the correct set pressure
- Has adequate capacity and is operationally reliable
- Is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

The effectiveness of a safety relief valve installation depends greatly on proper sizing and selection of the valve type, suitable installation conditions, and proper and timely testing of the valve.

Pressure Regulation

Good regulation of high-pressure gas is important for two reasons:

- To protect low-pressure equipment from becoming overpressured and becoming a hazard.
- If located near an orifice meter station, a regulator station must operate smoothly or it will result in a chart record which is impossible to interpret accurately.

Types of Regulator. The type of load to be controlled usually dictates the type of regulator to be selected:

- *Globe Bodied*: The globe-bodied control valve has been the standard for the gas industry for many years and performs well in a wide range of applications. When properly sized and mated with a good controller, it is very well-suited for difficult applications such as pressure control on a plant where load changes rapidly. However, it becomes very large and difficult to maintain when sized to control large loads with low pressure drops. The globe-bodied regulator is also inherently noisy.

  With some relatively new designs, the disadvantages of the globe-bodied control valve are being overcome. Patented trim designs control flowing velocities by forcing the gas through a large number of very small flow paths with multiple 90° turns. The resulting reduced flowing velocities effectively minimize erosion, noise, and vibration, and result in enhanced process control.

- *Expansible Tube*: The expansible tube regulator is extremely simple in its construction and principle of operation. On many applications it does not require a controller but operates with a pilot regulator.

  The expansible tube is by nature quieter than many regulators and it has good low-flow characteristics and tight shutoff. It does have a minimum differential pressure requirement of 10 to 50 psi (0.70 to 3.52 kg/cm^2), depending on size, which precludes its use in some applications.
- *Ball Valve*: The ball valve is best suited to large loads where small pressure drops are required. This is often the case in flow control applications or where pipeline pressure varies from time to time. The ball valve can perform a double duty when used as a monitor regulator and as an isolating valve on one side of a primary regulator.

  Ball valves are inherently noisy and can give erratic control if not maintained properly. Due to their large capacity, it is often important to consider pressure losses through adjacent piping when sizing this type of regulator.

Influence on Station Design. Whichever type regulator is selected, the way it is installed is important for successful operation. For most applications, it is best to have at least two parallel units. If the load varies widely, *split range* control is used, requiring two regulators, one to control low flows and a large-capacity unit to come in when required. For critical applications, it is desirable to have a standby regulator which would not normally be used but would open in an emergency.

When necessary to make a very large pressure reduction, it is best handled in two stages, with each regulator making about half the cut. Two-stage regulation can enhance measurement if one stage is placed on each side of the measuring station.

The upstream regulators should be used to control pressure in order to maintain a constant pressure at the measuring station. Downstream regulators can be used to control flow or to control customer pressure. As much volume as possible should be provided between the two regulator gauges; otherwise stable control may be difficult to achieve.

Overpressure Protection. The most important part of designing a regulator station is being as sure as possible that the system downstream cannot be overpressured. The first step in protection is strict compliance with all safety regulations and, in particular, Part 192 of the Department of Transportation Safety Regulations (DOT 192).

Basically DOT requires secondary protection if it is possible for the pressure upstream of a regulator to reach a level which will be dangerous to the downstream system. Secondary protection may be provided either by a monitor regulator installed in series with the primary regulator or by a relief valve.

There are systems, however, where a safety/relief valve may be the best selection. If a regulator feeding a small-capacity system fails suddenly, a monitor may be too slow to prevent the system from being overpressured. A relief valve should be provided on small downstream systems to take off valve leakage if the load is cut off completely.

Gas Metering

Efficient measurement and control of high-pressure natural gas is vital. A measurement error of only 1 percent can cost thousands of dollars a day at a single large-volume station.

Measurement. Measurement requirements in the gas industry can be broken into two broad categories:

1. *Custody Transfer:* Most important and demanding is custody transfer at a station measuring gas flowing from one company to another. The orifice meter has dominated the field in measurement of large volumes of gas at high pressure. However, turbine meters and rotary meters are being used more and more where better accuracy is justified.
2. *Control.* Control, or check measurement, is used for routing gas toward a customer, control of compressor stations, and so forth. Repeatability is the most important feature of such measurement, and the complexity and expense of custody transfer type metering are not usually justified.

Gas industry meters operate on simple physical principals and have a long history of reliable and accurate performance. The commonly used meters fall into two categories: *displacement types* such as diaphragm, rotary-lobed impeller, and rotary vane shown in Fig. C6.11 and C6.12; and *rate-of-flow (velocity)* meters such as orifice meters and turbine meters shown in Fig. C6.13.

Tables C6.9 and C6.10 list factors which affect selection of the five meter types used in the gas industry. The tables are intended as a guide and should not be used without further study when selecting the best meter for a particular application. Capacity ranges given in Table C6.9 are shown graphically in Fig. C6.14 The ranges are representative and are intended to give preliminary information for specific problems. Since the chart reflects information from many manufacturers, individual model lines may not have the exact capacity shown.

A relatively recent addition to the long line of meters available to the gas industry is the ultrasonic gas flow meter. An array of ultrasonic transducers placed at angles across the bore of the meter tube measure the time it takes for sound to travel in a number of parallel planes. Sound transit times are measured with and against the flow through the meter. Given that travel time in the direction of flow is less than that against the flow, and the transducer locations are a known constant, the mean velocity of the gas can be calculated by averaging the measurements from each plane. The accuracy of the ultrasonic meter has evolved to the point now that it can determine gas flow rates to custody transfer standards.

The major advantage of the ultrasonic gas flow meter is its nonintrusive design. There are no parts in the gas stream to obstruct flow. There are also no moving parts requiring lubrication and maintenance.

Leak Detection

Leak detection for both gas and liquid pipelines, and especially for those fluids such as ethane and propane that are sometimes liquid and sometimes gas, has been an industry problem for many years. Public attention to the subject is now widespread.

The safety record of the pipeline industry is quite good. Measured in terms of accidents (defined by the U.S. Department of Transportation regulations in terms of dollars and fluid loss) per 1000 mi (1600 km) of pipeline, deaths per ton mile of cargo moved, or any other scale, the pipeline record is better than other means of transportation by at least an order of magnitude.

The causes of leaks are many and varied, but over 70 percent are accounted for by accidental damage from external sources, corrosion, and defective pipe.

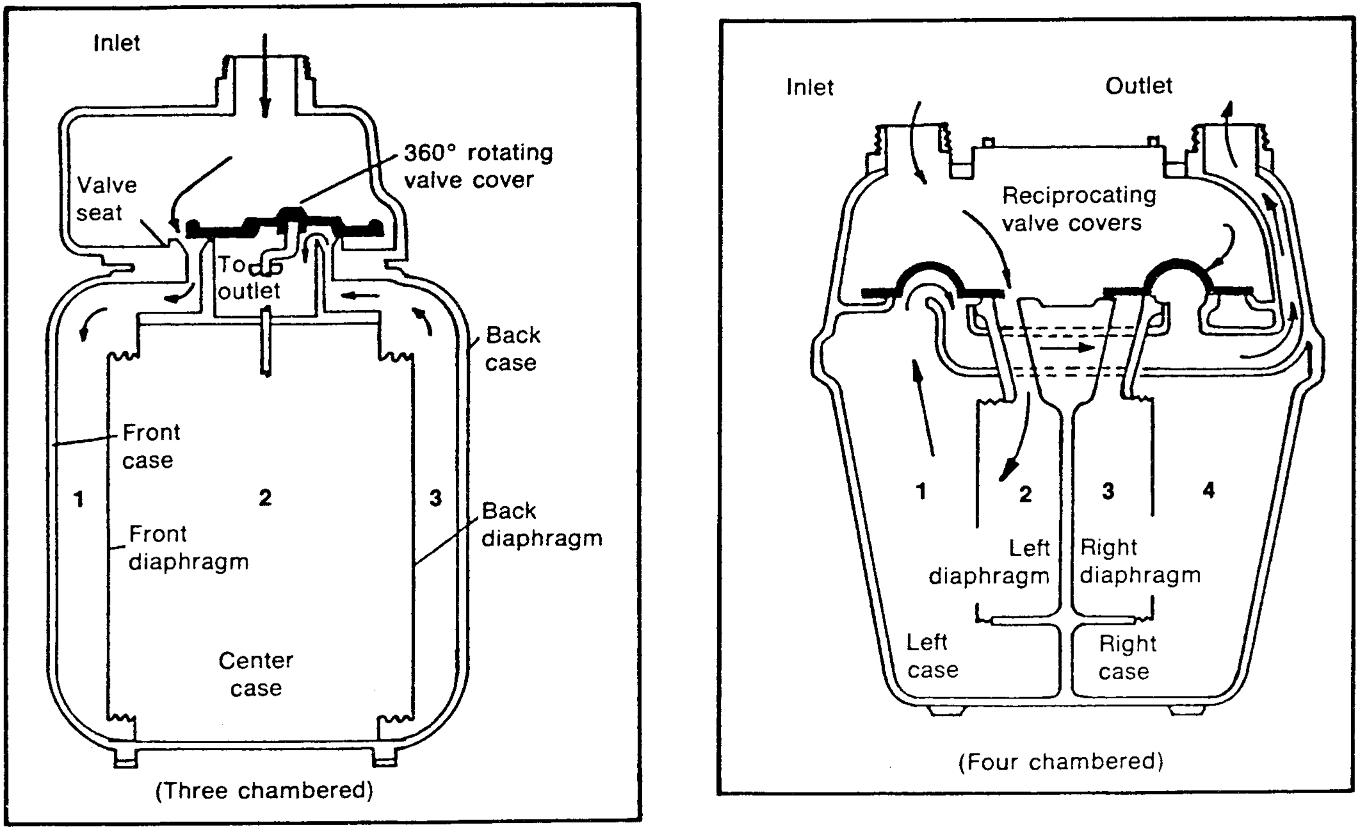


FIGURE C6.11 Diaphragm displacement meters operate by alternately filling chambers of known volume.

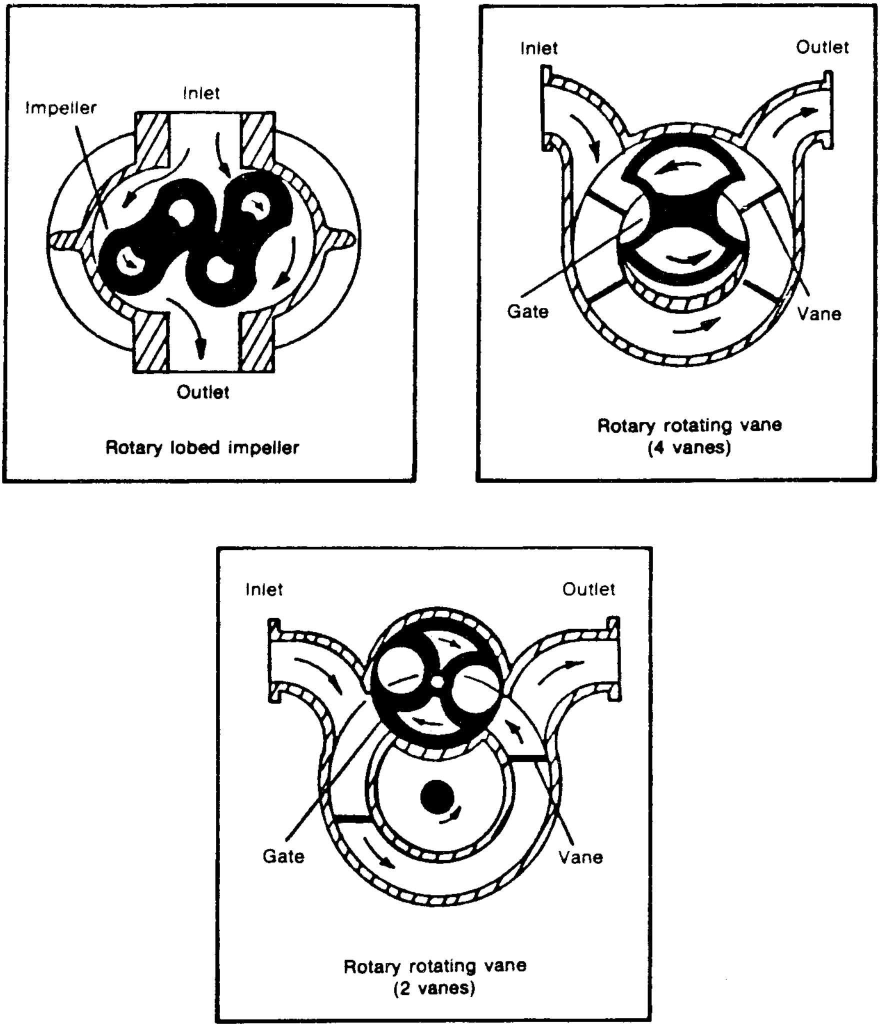
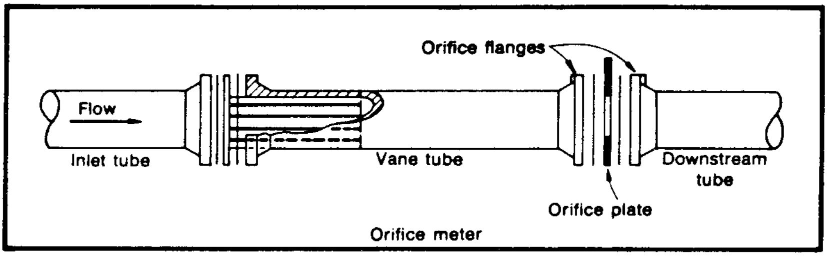


FIGURE C6.12 Rotary displacement meters, like diaphragm meters, measure gas flow by alternate filling and emptying of fixed volume chambers. A counter or dial registers the total gas amount.

Historically, the number one source of leaks has been external corrosion, but modern pipe coatings and the almost universal application of cathodic protection system in the last 60 years has all but eliminated corrosion leaks on the newer pipelines. Modern mill practices and more conscientious hydrostatic testing have almost eliminated defective pipe as a cause of leaks on new lines. Of ever-increasing importance, however, is the problem of damage to pipelines by construction machinery. The problem is made worse by the fact that the very machine that does the damage comes equipped with a spark or hot exhaust to ignite the leaking fuel. It



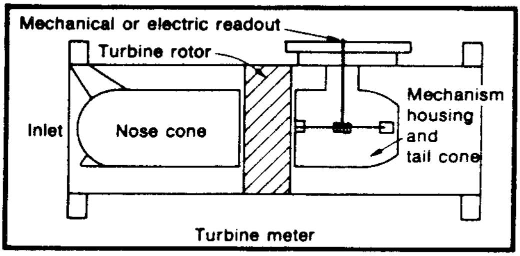


FIGURE C6.13 Velocity flow meters pass a steady gas stream. Flow is detected as a differential pressure in the orifice meter and as rotor movement in the turbine meter.

is recommended that such protective measures as extra-depth burial, concrete slabs and/or warning tapes buried above pipe, and extra line markers be considered at major road crossings and in city growth areas.

One of the problems with leak detection is the frustration of knowing that when a leak has been detected a large part of the damage has already been done. It is well and good to say that early remedial action is needed. However, one must know what action to take—for example, to immediately slam a mainline valve shut would almost invariably be the wrong thing to do on a liquid line. Any action following a leak signal must be thought out very carefully. The other frustrating problem with leak detection is that it may be impossible to do at any reasonable cost.

Rudimentary leak detection was carried out for years by reporting hourly meter readings. Minor differences in reading time, temperature, line pack, and so forth made the result somewhat erratic, but a continuous shortage in delivery on a small pipeline was sufficient cause to assume a leak. Large leaks or *line breaks* were detected (sometimes automatically) by the combinations of suction and discharge pressure with flow at pump stations; that is, falling discharge pressure combined with increased flow meant a leak downstream; falling suction combined with decreased flow meant a leak upstream. The difference today is in the magnitude of the problem. The ± 2 percent deficiency detectable on an NPS 8 (DN 200) line transporting 25 million cubic feet per day (25 MMCFD; 708 Mm^3/D) was a 0.5 MMCFD (14 Mm^3/D) leak. Today, the ± 0.2 percent deficiency (may be) detectable by a sophisticated leak detection system on an NPS 42 (DN 1050) line transporting 1000 MMCFD (28 MMm^3/D) is a 2 MMCFD (57 Mm^3/D) leak.

Some new, patented devices which "listen" for the pressure wave which is generated by a suddenly occurring leak are state of the art leak detection. Today

TABLE C6.9 Summary of Gas Meter Selection Factors

Factor	Gas properties						Meter characteristics							
	Maximum pressure[1]		Flowing fluid temperature limits				Base maximum capacity range						Pressure loss at base maximum capacity	
Meter type	psig	kg/cm²	°F	°C	Suitability for corrosive gas	Influence of condensate	Mcfh	m³/h	Accuracy % of reading 10 50 90	Base range-ability	Type of scale	Common construction materials[2]	psi	kg/cm²
Diaphragm displacement	1000	70.3	−30 to +140	−34 to +60	No	Potential	0.2 to 12	5.7 to 339.8	±1	200 : 1	Uniform	Al/Cl/Brass/ Plastic/Zinc alloy	0.02 to 0.07	0.001 to 0.005
Rotary rotating vane	1440	101.2	−40 to +145	−40 to +63	Yes (with special bearings & materials)	None	3 to 38	85 to 1076	±1	25 : 1	Uniform	Anod. AL/300/SS /Steel/Bronze	0.04	0.003
Rotary lobed impeller	1440	101.2	−40 to +140	−40 to +60	Yes (with special bearings & materials)	None	1.5 to 102	42.5 to 2888	±1	20 : 1	Uniform	AL/CI/Steel	0.7	0.005
Gas turbine	1440	101.2	−40 to +145	−40 to +63	Yes (with special materials)	None	4 to 150	113.3 to 4248	±1	5 : 1 to 25 : 1	Uniform	AL/DU/CS	0.04	0.003
Orifice	5000	351.5	−65 to +500	−54 to +260	Yes	Potential	22 to 1500	623 to 42477	±1½	3 : 1 to 4½ : 1	Square root	FS/SS/CS	2.5	0.176

[1] Refer to manufacturer's published literature for the maximum pressure rating of a specific meter size.
[2] Common construction materials: AL = Aluminum, CI = Cast iron; CS = Cast steel; DU = Ductile iron; FS = Forged steel; SS = Stainless steel.

TABLE C6.10 Summary of Gas Meter Selection Factors

Factor	Installation factors						Economic factors				
	Normal line size		Straight pipe reqmts (no. of pipe diameter)	Ambient temperature range				Life expectancy			
Meter type	NPS	DN		°F	°C	Limitations	Approx. first cost[3]	Between repairs (years)	Total (years)	Maintenance cost[4]	Installation cost[4]
Diaphragm displacement	¼ to 4	8 to 100	None	−30 to +40	−34 to +60	Horizontal	220	8 to 10	30 to 40	L	M
Rotary rotating vane	2 to 6	50 to 150	None	−40 to +145	−40 to +63	Not critical	130	3 to 6	10 to 25	M	L
Rotary lobed impeller	1.5 to 10	40 to 250	None	−40 to +140	−40 to +60	Horizontal and leveled	150	3 to 6	10 to 25	M	L
Gas turbine	2 to 12	50 to 300	4 to 10	−40 to +145	−40 to +63	Horizontal	125	3 to 6	10 to 25	M	L
Orifice	2 to 16	50 to 400	3 to 40	−40 to +170	−40 to +77	Horizontal	100	1 to 3	10 to 15	H	M

[3] First cost ratio is based upon a NPS 2 (DN 50) orifice meter sized to measure approximately 5 Mcfh (141.6 m^3/h) at atmospheric pressure.

[4] Maintenance and installation costs: H = High; M = Medium; L = Low.

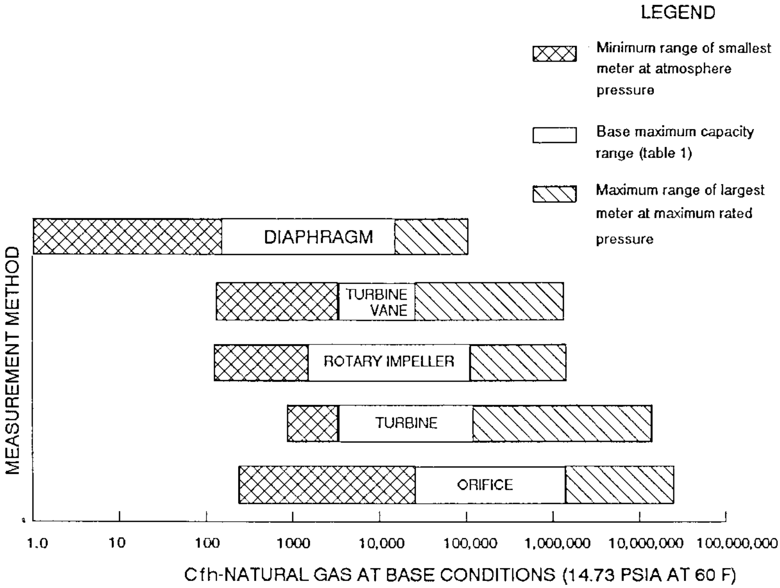


FIGURE C6.14 Gas measurement meter capacities.

a leak is defined as "the loss that can be measured with existing instrumentation" (probably about 0.1 percent of steady state flow).

Real-time computer modeling techniques have been developed which have already improved the sensitivity of old-fashioned "meter in-meter out" techniques even under transient flow conditions. Accuracy is achieved by the use of remote terminal units (RTUs), high-precision instrumentation, and an on-line computer.

Scrapers and Scraper Handling

Purpose of Scrapers and Spheres. At various times throughout the life of a pipeline a need is found to send a *scraper* (pig) or *sphere* through the line. This may be for any one or combination of the following:

- *Initial Cleaning*: On completion of a section of pipeline, at least one scraper is run to push out air as well as trash, rocks, weld slag, and so forth preparatory to hydrostatic testing.
- *Sizing Run*: Before a line is put in service, usually before hydrostatic testing, a scraper with a steel plate, or a "caliper" pig, is run in order to make sure the pipe was not damaged during construction and that all future pigs will pass unrestricted.
- *Dewatering Scrapers/Spheres*: During commissioning of the pipeline, a number of scrapers are used to displace the water left after hydrostatic testing.

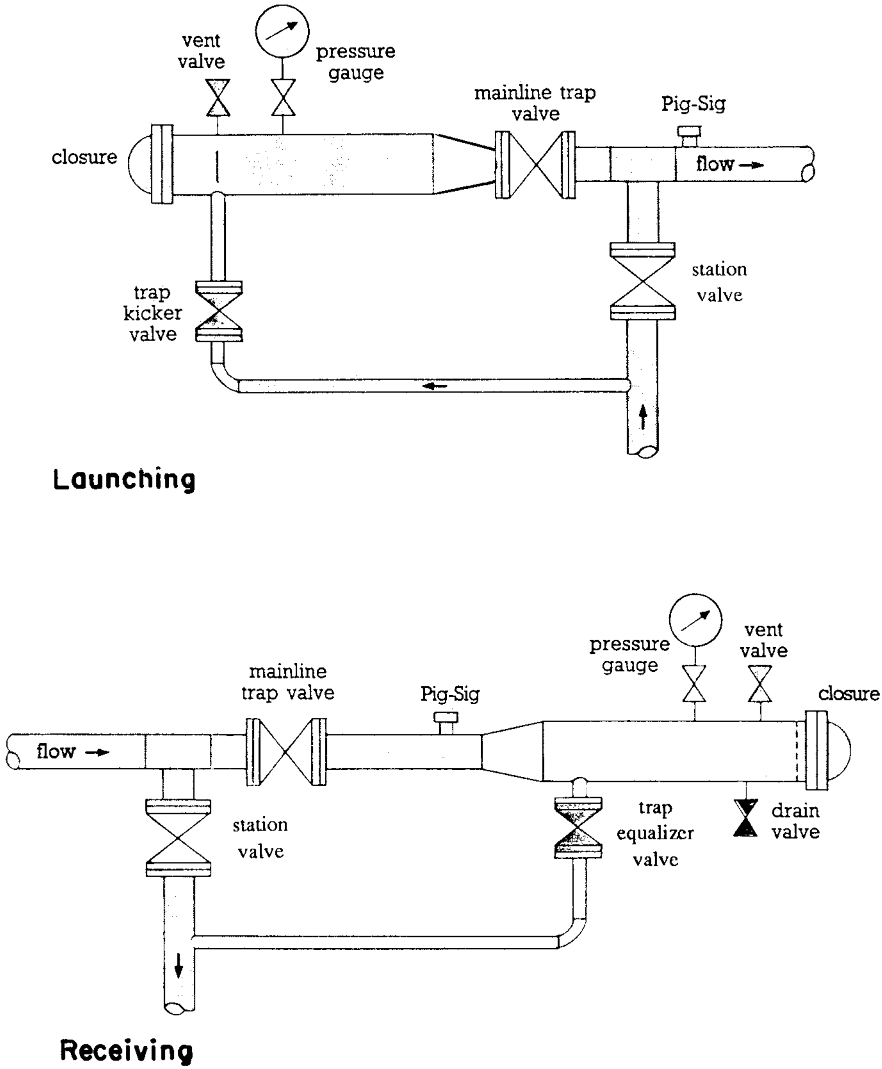


FIGURE C6.15 Launching and receiving scraper traps for gas service. *(T.D. Williamson.)*

- *In-Service Cleaning*: During normal pipeline operation pipelines accumulate water, corrosion products (rust, scale), condensate and compressor oil, sand, and dust which must be cleaned out on a regular basis to maintain efficiency of operation.
- *Deslugging*: On some two-phase pipelines, spheres are run on a scheduled basis to push condensate into the slug catchers.

- *Inspection*: Special instrumented "smart" pigs may be run from time to time to check corrosion, listen for leaks, or check damage after an accident.

Some of these uses require special scrapers with knives (for cutting waxy deposits) or brushes (for cleaning rust/scale) or noise making devices, and so forth.

Scraper Handling Devices. Because of the variety of uses for which scrapers are employed, a wide rang of scraper-handling equipment is required. The basic horizontal scraper trap has proved to be convenient for general services (see Fig. C6.15). There are two types of scraper traps, one for launching and one for receiving. The difference between the two is the point of entry of the bypass (kicker/equalizer) lines into the barrel, and sometimes the barrel length.

The traps are equipped with a barrel that has an internal diameter 2 to 4 in (50 to 100 mm) larger than that of the mainline, a hinged closure, a full-opening (through conduit) trap valve, side-entering barred tee, and a bypass line with a valve. The trap assembly launches or receives a scraper by pinching the station valve with the trap and the bypass valves both open. This controls the movement of the pig out of the launcher or into the receiver.

Scraper traps are placed at the initial and terminal points of the pipeline and at any other point where it is required to start or receive a scraper. It is not always necessary to put traps at a change in pipe size as multisized scrapers are available (within limits), nor is it necessary to put scraper traps at every compressor station. Usually it is the length of the pipeline section and the expected wear on the scraper that will indicate where scraper traps are required. Figure C6.16 is a simple piping diagram of the essential piping and valves in a booster station.

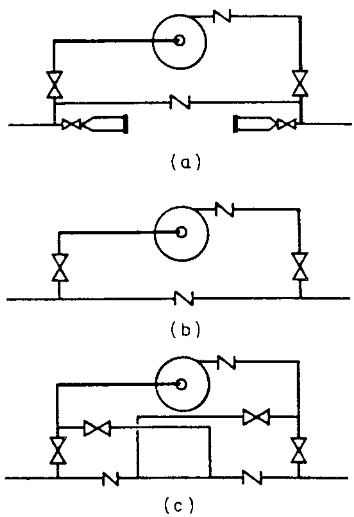


FIGURE C6.16 Piping arrangement for a station (*a*) with scraper traps, (*b*) without traps, where a scraper is passed by shutting down, and (*c*) with pipe and valving for bypass without shutdowns.

Pin Ball Machines. On some pipelines where spheres are used frequently for cleaning condensate or for separating product batches, a special adaptation of the basic scraper trap allows for loading of several spheres in the launcher and releasing them on signal or by timer. The receiver is long enough to receive as many spheres as can be launched. Both launcher and receiver are sloped so that gravity aids in the operation.

Layout. Scrapers and spheres are heavy, especially in the larger sizes, and may require davits or cranes to maneuver them into and out of the trap. Traps should also be located with truck and machinery access in mind. Gravity drainage to a sump tank should be provided to collect liquid from the trap drain connection and from spillage at the trap door.

CORROSION PROTECTION

Gas system pipelines are subject to both external and internal corrosion. In general, external corrosion is more serious in that it can drastically reduce the life of the pipeline and impair its safety. Internal corrosion, apart from exceptional cases of corrosive fluid components such as H_2S and CO_2, is usually a much more gradual process resulting in a lowering of pipeline efficiency. Regular line cleaning, as discussed in "Scrapers and Scraper Handling," can be utilized to take care of the pipe internally for most installations. However, with an unusually corrosive fluid, internal coatings or inhibition might also be needed.

The corrosion rate of steel is higher in low-resistance soils or seawater that it is in high-resistance soils such as dry sands. Corrosion rates are also higher in turbulent waters than when the water is stagnant.

The two principal parts of corrosion protection are *pipe coating* (or insulation) to increase the pipe to soil resistance and *cathodic protection* (impressed current or galvanic anodes) to make the pipe always cathodic.

Coatings

For many years pipelines were coated with processed natural substances such as asphalt or coal-tar enamels, usually reinforced with fiberglass mesh, and overwrapped with felt sheeting. Synthetic organic plastic materials have been developed relatively recently for external coatings and these are now in common use.

Coal Tar and Asphalt Enamels. These coatings are applied hot over a cold primer and usually reinforced with a fiberglass inner wrap and protected with a felt outer wrap. They were often applied "over the ditch" by special "coat and wrap" machines. Well-founded environmental concerns over the toxicity of the fumes from the hot coal tar and asphalt enamels have curbed their use. However, these coatings are still being plant-applied under strict controls.

Asphalt Mastics. This coating is commonly applied in a shop. It forms a thick ½ to ⅝ in (12.7 to 15.9 mm) layer around the pipe, and has mineral fillers which provide built-in reinforcement. Generally, it does not require an outer wrap.

Mastics have been extensively used for submarine lines, for swamp crossings, and for some land lines. They are not in common use today.

Extruded Plastic Coatings. These coatings are usually applied in a shop, after sandblast cleaning of the pipe and priming with a thin layer of mastic. They afford good protection because the mastic exudes through nicks or scratches and heals breaks in the coating. Other systems include a bonded polyethylene jacket with a nonbonded PVC (polyvinylchloride) outer rock-guard. Extruded coatings are often used where long-term dependability is required for city service or for swamp service. They are also used on submarine lines.

Tape Coatings. These coatings usually have an adhesive backing, and may be applied in a shop or yard, or over the ditch. Polyethylene and polyvinylchloride tapes are readily available. Polyethylene may be favored for its chemical, thermal, and physical stability.

Fusion-Bonded Epoxies. These are very thin coatings applied in a shop. The pipe is degreased, sandblasted, and heated to the fusion temperature. Epoxy powder is applied electrostatically and fuses to a uniform coat on the heated surface. Pinholes and other defects may be repaired with hot stock or with a liquid epoxy resin and catalyst compound. Refer to Chap. B10.

The coating is tough and easy to repair. However, it must not be too thick or it may crack during bending, and is subject to cathodic disbonding.

Field Joint Coatings. When each length of pipe has been coated individually, the field joint must still be protected after it is welded. Generally, the field joint coating material should be similar to the main pipe coating, and suitable for application in relatively uncontrolled field conditions.

Asphalt and coal tar enamels are usually applied by hand, along with the appropriate inner and outer wraps. Plastic tapes are also applied by hand.

For extruded plastic coatings, plastic shrink sleeves with mastic backing may be used. They are slipped over the pipe before the joint is welded, and are moved to cover the joint afterwards. Shrink sleeve wraps, which can be applied over the completed weld at any time, are also available. Application of heat then causes the plastic to shrink tightly down on the joint and on the coating to either side.

Mastic is usually made up by surrounding the joint with a thin metal shield and pouring hot mastic into the shielded space. This usually bonds well with the mastic to either side and makes a satisfactory tight joint.

Fusion-bonded epoxy coatings may be made up by heating the joint with a preheat coil and applying the resin powder. The pipe surfaces must be sandblasted before the powder is applied.

Liquid epoxy resin and catalyst compound, applied by hand, may also be used for field joint protection.

Internal Coatings. Where corrosive components are encountered in the gas being transported, the pipe can be protected internally by adding inhibitors to the fluid or by coating the pipe internal wall. An economic comparison can assist in making a choice. Continued use of inhibitors tends to be costly and introduces complications both in injection equipment and in the resultant effect on delivered gas analysis.

Coal tar and asphaltic components for internal coating are not difficult to apply, but if deterioration occurs during the life of the pipeline it can seriously affect the pipeline efficiency.

Epoxy coatings give good protection, long life, and a low friction factor. The main problem is to get a satisfactory bond between the shop-applied internal coating and the machine- or hand-applied coating on the joints after welding. This involves special application procedures which must be conscientiously followed in the field.

Cathodic Protection

Cathodic protection is a method of inhibiting corrosion that has been used for over a century. It is applicable to all types of pipe metals, although it is used mainly for steel pipe. The technique is to connect the pipeline to an anode bed and to make the pipe behave as a cathode by impressing a direct current voltage so that the anode bed corrodes and not the pipe. Where this is not practicable (as on long

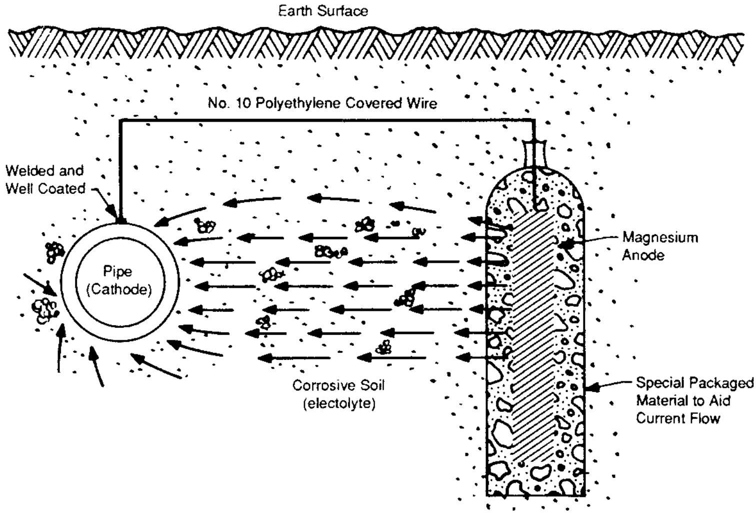


FIGURE C6.17 Magnesium anode protects coated steel pipe; current flows from anode through earth to pipe. *(Pipeline & Gas Journal, February 1984.)*

water crossings), passive protection may be attained by attaching sacrificial anodes directly to the pipe (see Fig. C6.17).

Cathodic protection is particularly important for coated pipe, to overcome the effect of pinholes or accidental breaks in the coating, which would otherwise permit local corrosion cells to form. Being localized, these cells are highly active and can rapidly penetrate the pipe wall.

Insulating flanges are necessary to ensure the integrity of the section of pipeline to be protected. Test leads installed at intervals along the length of the line during construction are used to monitor the voltage levels during the life of the pipeline. Regular measurements and maintenance, as required, ensure the continued effectiveness of the cathodic protection system.

Impressed Current Systems. Impressed current systems are generally installed where alternating current is available for the rectifier units (see Fig. C16.18). Since the units can be obtained in a wide range of output voltage and current combinations, they are used (1) where soil or water electrical resistivities are high and (2) where total current requirements are large.

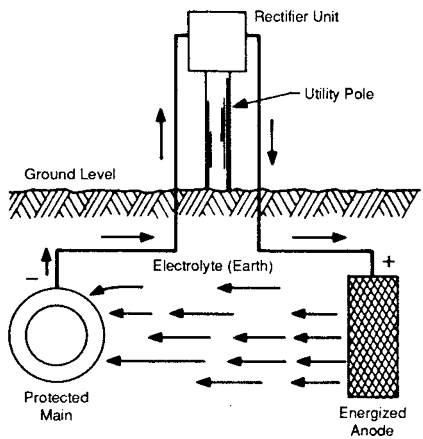


FIGURE C6.18 Additional current for cathodic protection requires use of a rectifier. *(Pipeline & Gas Journal, February 1984.)*

Direct current for cathodic protection is provided by a transformer-rectifier combination. Where alternating current is not available for standard rectifier units, alternative direct current sources that can be used are thermoelectric generators, diesel generators, and solar power systems.

Typical anode materials for impressed current systems are graphite, high-silicon iron, lead-silver alloys, and platinum on a titanium or columbium substrate. On occasion scrap steel is used, but usually only because of its availability. As an anode material, steel is consumed at a rate of about 20 lb (9.1 kg) per ampere year. Consumption for graphite and silicon iron is approximately 1 lb (0.45 kg) per ampere year, for lead-silver about 0.1 lb (0.045 kg) per ampere year, and for platinum about 6 to 20 milligrams per ampere year.

Galvanic Protection. Galvanic protection is a passive system which depends on the principle that coupling two dissimilar metals in the same electrolytic environment causes accelerated corrosion of the more active metal and protection of the less active metal. The more active metal is preferentially consumed and is, therefore, called a *sacrificial anode.*

Galvanic protection is often used in preference to an impressed current installation as a temporary measure during construction or when the current requirements are low and the electrolyte has relatively low resistivity (less than 10,000 ohm-centimeters). Clearly, it has an advantage when there is no source of electrical power, or when a completely underground system is desired. Capital investment will generally be lower and is often the most economical method for short-life protection.

Insulating Joints

Insulating joints are required for electrical isolation of the cathodically protected section of the pipe from those sections not protected. In their simplest form, the joints may be flange connections with special arrangements of insulating gaskets, washers, and sleeves to prevent electrical contact between the bolts and the flanges. Preferably, they may be special unitized couplings in which the insulating features are factory-assembled, and the entire assembly can be welded into the pipeline (see Figs. C6.19 and C6.20).

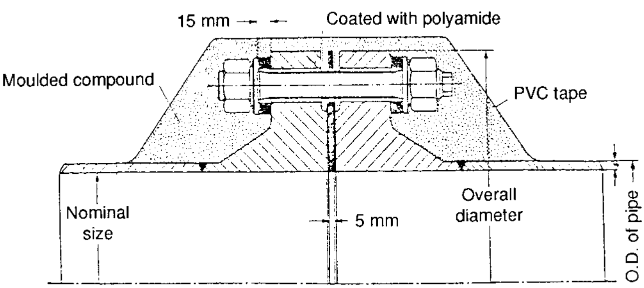


FIGURE C6.19 Insulating flange connection for laying in the ground. *(Eisenbau Albert Ziefle KG.)*

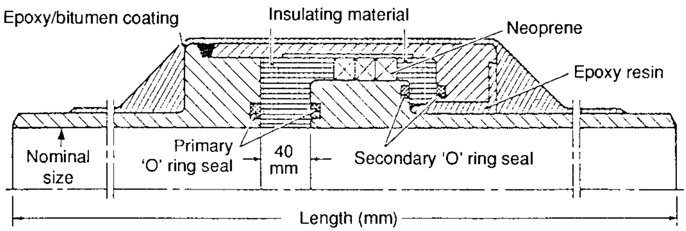


FIGURE C6.20 Monobloc insulating coupling ready for erection by welding in. *(Eisenbau Albert Ziefle KG.)*

Insulating flange connections are made above ground whenever possible. This simplifies installation, makes periodic inspection easier, and minimizes the possibility of a short circuit across the joint.

For underground installation an external application of bitumen or compound molding, covering the whole insulated flange connection, protects it against corrosion and dirt and is absolutely necessary for maintaining the insulating properties of the joint.

INSPECTION AND TESTING

Inspection

ASME B31.8 requires that for piping systems that will operate at 20 percent or more of the specified minimum yield strength of the pipe, the quality of welding must be checked by nondestructive inspection. Such inspection may consist of radiographic examination, magnetic particle testing, or other acceptable methods. The trepanning method of nondestructive testing is specifically prohibited.

ASME B31.8 further specifies that the minimum number of field butt welds to be selected on a random basis from each day's construction for examination must be as noted below. Each weld so selected must be examined over its entire circumference, or as an alternative, the equivalent length of weld must be examined if only a section of the circumference of each weld is examined.

1. 10 percent of welds in Class 1 locations.
2. 15 percent of welds in Class 2 locations.
3. 40 percent of welds in Class 3 locations.
4. 75 percent of welds in Class 4 locations.
5. 100 percent of welds in offshore pipelines, in compressor stations, and at major or navigable river crossings, major highway crossings, and railroad crossings, if practical, but in no case less than 90 percent. All tie-in welds not subjected to a pressure proof test must be examined.

All welds which are inspected must meet the standards of acceptability of the American Petroleum Institute Standard API 1104. If a weld does not, it must be repaired and reinspected.

TABLE C6.11 Test Requirements for Pipelines and Mains to Operate at Hoop Stresses of 30% or More of the Specified Minimum Yield Strength of the Pipe

1	2	3	4	5
Location class	Permissible test fluid	Pressure test prescribed: Minimum	Pressure test prescribed: Maximum	Maximum allowable operating pressure, the lesser of
1 Division 1	Water	1.25 × m.o.p.	None	t.p., 1.25
1 Division 2	Water	1.1 × m.o.p.	None	t.p., 1.1
	Air	1.1 × m.o.p.	1.1 × d.p.	or d.p.
	Gas	1.1 × m.o.p.	1.1 × d.p.	
2	Water	1.25 × m.o.p.	None	t.p., 1.25
	Air	1.25 × m.o.p.	1.25 × d.p.	or d.p.
3&4 [Note (1)]	Water	1.40 × m.o.p.	None or d.p.	t.p., 1.40 or d.p.

m.o.p. = maximum operating pressure (not necessarily the maximum allowable operating pressure); d.p. = design pressure; t.p. = test pressure.

General note: This table brings out the relationship between test pressures and maximum allowable operating pressures subsequent to the test. If an operating company decides that the maximum operating pressure will be less than the design pressure, a corresponding reduction in prescribed test pressure may be made as indicated in the Pressure Test Prescribed, Minimum, column. However, if this reduced test pressure is used, the maximum operating pressure cannot later be raised to the design pressure without retesting the line to the test pressure prescribed in the Pressure Test Prescribed, Maximum, column. See paras. 805.214, 845.213, and 845.214 of ASME B31.8.

Note: (1) For exceptions, see para. 841.322(d) of ASME B31.8.

If the pipe is intended to operate at 40 percent or less of the specified minimum yield strength, and pipe size is less than NPS 6 (DN 150), or the number of welds to be inspected is small enough to make nondestructive testing impractical, welding may be inspected visually and approved by a qualified welding inspector.

Testing

ASME B31.8 requires that all pipelines and mains which will be operated at a hoop stress of 30 percent or more of the specified minimum yield strength of the pipe must be given a test for at least 2 hours to prove strength after construction and before being placed in operation. The test requirements are summarized in Table C6.11.

Pipelines and mains operating at less than 30 percent of the specified minimum yield strength of the pipe, but greater than 100 psi (7 kg/cm^2), must be tested as follows:

- In Class 1 locations, a leak test must be made at a pressure in the range from 100 psi (7 kg/cm^2) to that pressure required to produce a hoop stress of 20 percent of the specified minimum yield strength, in all cases where the line is to be stressed to 20 percent or more of the specified minimum yield strength of the pipe and gas or air is the test medium.

- In Class 2, 3, and 4 locations, at the least in accordance with the requirements listed in Table C6.11, except that gas or air may be used as the test medium within the maximum limits sent in Table C6.12.

TABLE C6.12 Maximum Hoop Stress Permissible During Test, % of Specified Minimum Yield Strength

Test medium	Class location 2	Class location 3	Class location 4
Air	75%	50%	40%
Gas	30%	30%	30%

For pipelines and mains that will operate at less than 100 psi (7 kg/cm^2), gas may be used as the test medium at the maximum pressure available in the distribution system at the time of the test.

OPERATION AND MAINTENANCE

The ASME B31.8 Code has established comprehensive guidelines for the operation and maintenance of gas transmission systems. Pertinent sections are paraphrased here.

Pipeline Maintenance

Continuing Surveillance of Pipelines. To maintain the integrity of a pipeline system, procedures for the continuing surveillance of its facilities must be established and implemented. Where unusual operating and maintenance conditions occur, such as failures, leakage history, drop in flow efficiency due to internal corrosion, or substantial changes in cathodic protection requirements, appropriate action must be taken.

When a facility is in unsatisfactory condition, a planned program must be initiated to abandon, replace, or recondition and proof test the facility. If the facility cannot be reconditioned or phased out, the maximum allowable operating pressure must be reduced in accordance with code requirements.

Pipeline Patrolling. A periodic pipeline program must be implemented to observe surface conditions on and adjacent to the pipeline right-of-way, indications of leaks, construction activity other than that performed by the company, and any other factors affecting the safety and operation of the pipeline. Patrols must be performed:

- At least once each year in Class 1 and 2 locations
- At least once each 6 months in Class 3 locations
- At least once each 3 months in Class 4 locations

Weather, terrain, size of line, operating pressure, and other conditions will be factors in determining the need for more frequent patrol. Main highways and railroad crossings must be inspected with greater frequency and more closely than pipelines in open country.

Maintenance of Cover at Road Crossings and Drainage Ditches. If the cover over the pipeline at road crossings and drainage ditches has been reduced below the requirements of the original design and is found to be unacceptable, additional protection such as barriers, culverts, concrete pads, casing, lowering of the line, or other suitable means must be provided.

Maintenance of Cover in Cross-Country Terrain. Where the cover over the pipeline in cross-country terrain does not meet the original design, and it is determined to be at an unacceptable level, additional protection must be provided by replacing cover, lowering the line, or other suitable means.

Leakage Surveys. Periodic leakage surveys on the line must be a part of any company's operating and maintenance plan. The type of surveys selected must be effective for determining if potentially hazardous leakage exists. The extent and frequency of such surveys must be determined by the operating pressure, piping age, class location, and whether the transmission line transports gas without an odorant.

Pipeline Markers. Signs or markers must be installed where necessary to indicate the presence of a pipeline at road, highway, railroad, and stream crossings. Additional signs and markers must be installed along the remainder of the pipeline at locations where there is a probability of damage or interference.

The signs or markers must include the words ''Gas (or name of gas transported) Pipeline,'' the name of the operating company, and the telephone number (including area code) where the operating company can be contacted.

Distribution Piping Maintenance

Patrolling. Distribution mains must be patrolled in areas where construction activity, physical deterioration of exposed piping and supports, or any natural causes could result in damage to the pipe. The frequency of the patrolling must be a function of the severity of the conditions which could cause failure or leakage and the subsequent hazards to public safety.

Leakage Surveys. The type or types of surveys selected for the operating and maintenance plan of a company's gas distribution system must be effective for determining if potentially hazardous leakage exists. Some procedures which may be employed are:

- Surface gas detection surveys
- Subsurface gas detector survey (including bar hole surveys)
- Vegetation surveys
- Pressure-drop test
- Bubble leakage test
- Ultrasonic leakage test

Miscellaneous Facilities Maintenance

Compressor Station Maintenance. The starting, operating, and shutdown procedures for all gas compressor units must be established by the operating company and appropriate steps taken to see that the approved practices are followed.

Inspection and Testing of Relief Valves. All pressure-relieving devices in compressor stations must be inspected or tested or both, and all devices except rupture disks must be operated periodically to determine that they open at the correct set pressure. Any defective or inadequate equipment found must be promptly repaired or replaced. All remote-control shutdown devices must be inspected and tested at least annually to determine that they function properly.

Isolation of Equipment for Maintenance or Alterations. Procedures must be established and followed for the isolation of units or sections of piping for maintenance, and for purging prior to returning units to service.

Storage of Combustible Materials. All flammable or combustible materials in quantities beyond those required for everyday use or other than those normally used in compressor buildings must be stored in a separate structure built of noncombustible material located a suitable distance from the compressor building. All above-ground oil or gasoline storage tanks must be protected in accordance with NFPA 30.

Maintenance of Pressure-Limiting and Pressure-Regulating Stations. All pressure-limiting stations, relief devices, and other pressure-regulating stations and equipment must be subject to systematic, periodic inspections and suitable tests, or reviewed to determine that they are:

1. In good mechanical condition. Visual inspections must be made to determine that equipment is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. The following must be included in the inspection where appropriate:
   - ***a.*** Station piping supports, pits, and vaults for general condition and indications of ground settlement.
   - ***b.*** Station doors and gates and pit vault covers to ensure that they are functioning properly and that access is adequate and free from obstructions
   - ***c.*** Ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions
   - ***d.*** Control, sensing, and supply lines for conditions which could result in a failure
   - ***e.*** All locking devices for proper operation
   - ***f.*** Station schematics for correctness

2. Adequate from the standpoint of capacity and reliability of operation for the service in which they are employed and set to function at the correct pressure.
   - ***a.*** If acceptable operation is not obtained during the operational check, the cause of the malfunction must be determined and the appropriate components must be adjusted, repaired, or replaced as required. After repair, the components must again be checked for proper operation.
   - ***b.*** At least once each calendar year, relief valves must be reviewed for sufficient capacity. If it is determined that the relieving equipment is of insufficient capacity, new or additional equipment must be installed to provide adequate capacity.

Whenever abnormal conditions are imposed on pressure or flow control devices, the incident must be investigated, and the device inspected and/or repaired. Abnormal conditions may include regulator bodies which are subjected to erosive service conditions or contaminants from upstream construction and hydrostatic testing.

1. An inspection or test, or both, of stop valves must be made to ensure that the valves will operate and are correctly positioned. The following must be included:
   - ***a.*** Station inlet, outlet, and bypass valves
   - ***b.*** Relief device isolating valves
   - ***c.*** Control, sensing, and supply line valves

2. The final inspection procedure must include the following:
   - ***a.*** A check for proper position of all valves with special attention given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines
   - ***b.*** Restoration of all locking and security devices to proper position

Valve Maintenance

Pipeline Valves. Pipeline valves required to operate during an emergency must be inspected periodically and partially operated at least once a year to provide safe and proper operating conditions.

1. Routine valve maintenance procedures must at the least include the following:
   - ***a.*** Servicing in accordance with written procedures by adequately trained personnel
   - ***b.*** Accurate system maps for use during routine or emergency conditions
   - ***c.*** Valve security to prevent service interruptions, tampering, etc., as required
   - ***d.*** Employee training programs to familiarize personnel with the correct valve maintenance procedures

2. Emergency valve maintenance procedures include:
   - ***a.*** Written contingency plans to be followed during any type emergency
   - ***b.*** Training personnel to anticipate all potential hazards
   - ***c.*** Furnishing tools and equipment as required, including auxiliary breathing equipment, to meet anticipated emergency valve servicing and/or maintenance requirements

Distribution System Valves. Valves used for the safe operation of a gas distribution system must be checked and serviced, including lubrication where necessary, at sufficient frequent intervals to assure their satisfactory operation. Inspection must include checking of alignment to permit use of a key or wrench and clearing from the valve box or vault any debris which would interfere with or delay the operation of the valve. System maps showing valve location should be available.

Service Line Valves. Outside shutoff valves installed in service lines supplying places of public assembly, such as theaters, churches, schools, and hospitals, must be inspected and lubricated where required at sufficiently frequent intervals to assure their satisfactory operation. The inspection must determine if the valve is accessible, if the alignment is satisfactory, and if the valve box or vault, if used, contains debris which would interfere with or delay the operation of the valve. Unsatisfactory conditions encountered must be corrected.

Valve Records. A record must be maintained for locating all pipeline valves and distribution system valves which are needed for safe system operation or may need to be operated under emergency conditions. These records may be maintained on operating maps, separate files, or summary sheets, and must be readily accessible to personnel required to respond to emergencies.

Prevention of Accidental Operation. To prevent accidental operation of any of the valves covered above, certain precautions must be taken. Some recommended actions are as follows:

- Lock valves in above-ground settings readily accessible to the general public, that are not enclosed by a building or fence.
- Lock valves located in vaults, if accessible to the general public.
- Identify the valve by tagging, color coding, or any other suitable means of identification.

DECOMMISSIONING/ABANDONMENT

Guidelines for decommissioning or abandoning gas transmission facilities are given in the ASME B31.8 Code. Pertinent sections are paraphrased here for reference.

Abandoning of Transmission Facilities

Any plan for abandoning transmission facilities must include the following provisions.

- Facilities to be abandoned must be disconnected from all sources and supplies of gas such as other pipelines, mains, crossover piping, meter stations, control lines, and other appurtenances.
- Facilities to be abandoned in place must be purged of gas with an inert material and the ends sealed, except that:
- if precautions are taken to ensure that no liquid hydrocarbons remain in the facilities to be abandoned, the facilities may be purged with air. If the facilities are purged with air, precautions must be taken to ensure that a combustible mixture is not present after purging.

Abandoning of Distribution Facilities

To abandon inactive facilities, such as service lines, mains, control lines, equipment, and appurtenances for which there is no further planned use, the following provisions must be addressed:

- If the facilities are abandoned in place, they must be physically disconnected from the piping system. The open ends of all abandoned facilities must be capped, plugged, or otherwise effectively sealed. The need for purging the abandoned facility to prevent the development of a potential combustion hazard must be considered and appropriate measures taken. Abandonment is not complete unless the volume of gas or liquid hydrocarbons contained within the abandoned section has been determined to pose no potential hazard. Air or inert gas may be used for purging, or the facility may be filled with water or other inert material. If air is used for purging, the facility must be checked to ensure that a combustible mixture is not present after purging. Consideration must also be given to any effects the abandonment may have on an active cathodic protection system and appropriate action taken.

- In cases where a main is abandoned, together with the service lines connected to it, insofar as service lines are concerned, only the customer's end of such service lines need be sealed as stipulated above.
- Service lines abandoned from the active mains should be disconnected as close to the main as practicable.
- All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.
- All above-grade valves, risers, and vault and valve box covers must be removed. Vault and valve box voids must be filled with suitable compacted backfill material.

Temporarily Disconnected Facilities

Whenever service to a customer is discontinued, one of the following actions must be taken:

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

REFERENCES

1. Gary B. Emerson, ‘‘Relief Valve Sizing, Selection, Installation and Testing,’’ *Pipeline Industry*, February 1987, pp. 25–32.
2. Richard C. Berger, ‘‘How Construction Forces Can Control Corrosion,’’ *Pipeline & Gas Journal*, February 1984, pp. 29–32.
3. Richard A. Sutton, ‘‘How Columbia Gas Selects Distribution Meters’’ *(Part 1), Pipeline Industry*, December 1978, pp. 33–38.
4. Richard A. Sutton, ‘‘How Columbia Gas Selects Distribution Meters’’ *(Part 2), Pipeline Industry*, January 1979, pp. 51–53.
5. D.M. Coulter and M.F. Bardon, ‘‘Revised Equation Improves Flowing Gas Temperature Prediction,’’ *The Oil and Gas Journal*, February 26, 1979, pp. 107–108.
6. Charles E. Schorre, ‘‘Flow Temperature in a Gas Pipeline,’’ *The Oil and Gas Journal*, September 27, 1954, pp. 26–28.
7. Gas Processors Suppliers Association, *Engineering Data Book*, Eleventh Edition, 1998.
8. The American Society of Mechanical Engineers, ASME Code for Pressure Piping, B31, An American National Standard, ‘‘Gas Transmission and Distribution Piping Systems,’’ ASME B31.8, 1995 Edition, through 1997 Addenda.
9. C.F. Colebrook, *J. Inst. Civil Engrs.*, London, 11:1333 (1938).