Gas Pipeline Hydraulics

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Introduction to gas pipeline hydraulics

This online course on gas pipeline hydraulics covers the steady state analysis of compressible fluid flow through pipelines. Mathematical derivations are reduced to a minimum, since the intent is to provide the practicing engineer a practical tool to understand and apply the concepts of gas flow in pipes. In particular, we will cover natural gas pipeline transportation including how pipelines are sized for a particular flow rate, the pressure required to transport a given volume of gas and the compression horsepower required. The properties of natural gas that affect pipe flow will be reviewed first followed by the concepts of laminar and turbulent flow and Reynolds number. Frictional pressure loss and the method of calculating the friction factor using the Moody diagram and the Colebrook and AGA methods will be illustrated with examples. Several other popular flow equations, such as the Weymouth and Panhandle formulas will be introduced and explained with example problems. Increasing pipeline throughput using intermediate compressor stations as well as pipe loops will be discussed. The strength requirement of pipes, allowable operating pressure and hydrostatic test pressure will be reviewed with reference to the DOT code requirements. Several fully solved example problems are used to illustrate the concepts introduced in the various sections of the course. A multiple choice quiz is included at the end of the course.

1. Properties of Gas

Gases and liquids are generally referred to as fluids. Gases are classified as compressible fluids because unlike liquids, gases are subject to large variations in volume with changes in pressure and temperature. Liquids on the other hand are generally considered to be incompressible. Liquid density and volume change very little with pressure. However, liquids do show a variation in volume as the temperature changes. The mass of a gas is the quantity of matter and does not change with temperature or pressure.

Mass of gas is measured in slugs or pound mass (lbm) in the U.S. Customary system of units (USCS). In the Systeme International (SI) units, mass is measured in kilograms (kg). Weight is a term that is sometimes used synonymously with mass. Strictly speaking, weight of a substance is a force (vector quantity), while mass is a scalar quantity. Weight depends upon the acceleration due to gravity and hence depends upon the geographical location. Weight is measured in pounds (lb) or more correctly in pound force (lbf) in the USCS units. In SI units weight is expressed in Newton (N). If the weight of a substance is 10 lbf, its mass is said to be 10 lbm. The relationship between weight W in lb and mass M in slugs is as follows:

$$W = Mg \tag{1.1}$$

where g is the acceleration due to gravity at the specific location. At sea level, it is equal to 32.2 ft/s^2 in USCS units and 9.81 m/s^2 in SI units.

Volume of a gas is the space occupied by the gas. Gases fill the container that houses the gas. The volume of a gas generally varies with temperature and pressure. However, if the gas occupies a fixed volume container, increasing the pressure will increase the gas temperature, and vice versa. This is called Charles Law for gases. If the gas is contained in a cylindrical vessel with a piston and a weight is placed on the piston, the pressure within the gas is constant equal to the weight on the piston, divided by the piston area. Any increase in temperature will also increase the gas volume by the movement of the piston, while the gas pressure remains constant. This is another form of the Charles Law for gases. Charles law will be discussed in more detail later in this section. Volume of a gas is measured in cubic feet (ft^3) in the USCS units and cubic meters (m^3) in SI units.

Density of a gas is defined as the mass per unit volume as follows:

$$\text{Density} = \text{mass} / \text{volume} \tag{1.2}$$

Therefore density is measured in slug/ft^3 or lbm/ft^3 in USCS units and in kg/m^3 in SI units. Similar to volume, gas density also varies with temperature and pressure. Since density is inversely proportional to the volume from Eq. (1.2), we can conclude that density increases with pressure while the volume decreases. Similarly, increase in temperature decreases the density, while volume increases.

Specific weight of a gas refers to the weight per unit volume. It is referred to in lb/ft^3 in USCS units and N/m^3 in SI units. It is defined as:

Specific weight = weight of gas / volume occupied (1.3)

The specific weight, like the volume of a gas, varies with the temperature and pressure. If the weight of a certain quantity of gas is 10 lb and the volume occupied is 1000 ft^3, the specific weight is $\frac{10}{1000}$ or 0.01 lb/ft^3. On the other hand the density of this gas can be stated as 0.01 lbm/ft^3 or $\left(\frac{0.01}{32.2}\right)$ = 0.00031 slug/ft^3. Therefore, specific weight and density are closely related.

Specific volume of gas is the inverse of the specific weight and is expressed in ft^3/lb in the USCS units and m^3/N in SI units. It is defined as:

Specific volume = volume of gas / weight of gas (1.4)

Specific gravity of a fluid is defined as a ratio of the density of the fluid to that of a standard fluid such as water or air at some standard temperature. For liquids, water is the standard of comparison, while for gases air is used as the basis.

Specific gravity of gas = density of gas / density of air (at the same temperature) (1.5)

Being a ratio of similar properties, the specific gravity is dimensionless. Thus the specific gravity of a particular gas may be stated as 0.65 relative to air at 60 ^{O}F. Sometimes, specific gravity is abbreviated to gravity and may be stated as follows:

Gravity of gas = 0.65 (air = 1.00)

Using molecular weights, we can define the gas gravity as the ratio of the molecular weight of the gas to that of air. The molecular weight of air is usually considered to be 29.0 and therefore, the specific gravity of gas can be stated as follows:

$$G = \frac{Mw}{29.0} \tag{1.6}$$

where:

G = specific gravity of gas, dimensionless

Mw = molecular weight of gas

The specific gravity of a gas, like its density, varies with temperature and pressure.

Viscosity of a fluid relates to the resistance to flow of the fluid. The higher the viscosity, the more difficult it is to flow. The viscosity of a gas is very small compared to that of a liquid. For example, a typical crude oil may have a viscosity of 10 centipoise (cP), whereas a sample of natural gas has a viscosity of 0.0019 cP. Viscosity may be referred to as absolute or dynamic viscosity measured in cP or kinematic viscosity measured in centistokes (cSt). Both these units are SI units, but commonly used even when working with USCS units. Other units of viscosity in USCS units are lb/ft-s for dynamic viscosity and ft^2/s for kinematic viscosity.

Specific heat of a gas is defined as the quantity of heat required to raise the temperature of one lb of gas by one ^{O}F. For gases, two specific heats are used: Cp, the specific heat at constant pressure and Cv, the specific heat at constant volume. The ratio of the specific heats $\frac{Cp}{Cv}$ is designated as γ and is an important parameter in flow of gases and in expansion and contraction of gases.

Pressure of a gas must be defined before we get on with the other important properties concerning gas flow. Pressure is defined as the force per unit area acting at any point in the gas. Imagine a container of volume V occupied by a certain mass of gas M as shown in Fig. 1.1.

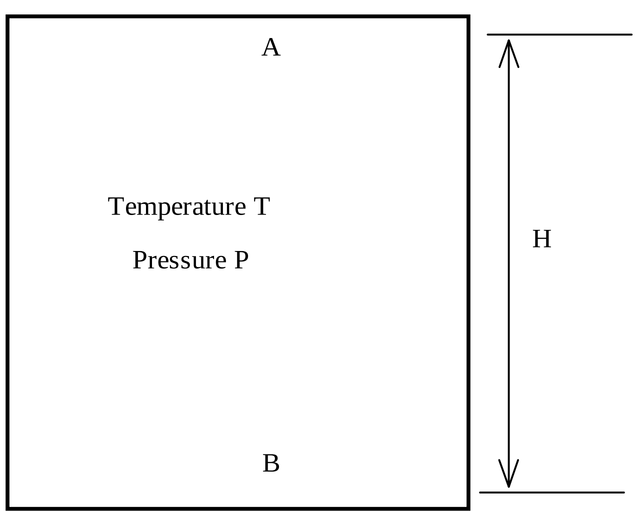

Fig. 1.1 Pressure in a gas

The gas is contained within this volume at some temperature T and pressure P and is in equilibrium. At every point within the container there is said to be a constant pressure P. Since the density of gas, compared to that of a liquid, is very small, the pressure of the gas at a point A near the top of the container will be the same as that at a point B near the bottom of the container. If the difference in elevations between the two points is H, theoretically, the pressure of gas at the bottom point will be higher than that at the top point by the additional weight of the column of gas of height H. However, since the gas density is very small, this additional pressure is negligible. Therefore we say that the pressure of gas is constant at every point within the container. In USCS units, gas pressure is expressed in lb/in^2 or psi and sometimes in lb/ft^2 or psf. In SI units, pressure is stated as kilopascal (kPa), megapascal (MPa), bar or kg/cm^2. When dealing with gases it is very important to distinguish between gauge pressure and absolute pressure. The absolute pressure at any point within the gas is the actual pressure inclusive of the local atmospheric pressure (approximately 14.7 psi at sea level). Thus in the example above, if the local atmospheric pressure outside the gas container is P_{atm} and the gas pressure in the container as measured by a pressure gauge is P_g, the absolute or total gas pressure in the container is:

$$P_{abs} = P_g + P_{atm} \tag{1.7}$$

The adder to the gauge pressure is also called the base pressure. In USCS units, the gauge pressure is denoted by psig while the absolute pressure is stated as psia. Therefore, if the gauge pressure is 200 psig and the atmospheric pressure is 14.7 psi, the absolute pressure of the gas is 214.7 psia. In most equations involving flow of gases and the gas laws, absolute pressure is used. Similar to absolute pressure, we also refer to the absolute temperature of gas. The latter is obtained by adding a constant to the gas temperature. For example, in USCS units, the absolute temperature scale is the Rankin scale. In SI units, Kelvin is the absolute scale for temperature. The temperature in ^{O}F or ^{O}C can be converted to absolute units as follows:

$$^{O}R = {}^{O}F + 460 \tag{1.8}$$

$$K = {}^{O}C + 273 \tag{1.9}$$

Note that degrees Rankin is denoted by ^{O}R whereas for degrees Kelvin, the degree symbol is dropped. Thus it is common to refer to the absolute temperature of a gas at 80 ^{O}F as (80 + 460) = 540 ^{O}R and if the gas was at 20 ^{O}C, the corresponding absolute temperature will be (20 + 273) = 293 K. In most calculations involving gas properties and gas flow, the absolute temperature is used.

The Compressibility factor, Z is a dimensionless parameter less than 1.00 that represents the deviation of a real gas from an ideal gas. Hence it is also referred to as the gas deviation factor. At low pressures and temperatures Z is nearly equal to 1.00 whereas at higher pressures and temperatures it may range between 0.75 and 0.90. The actual value of Z at any temperature and pressure must be calculated taking into account the composition of the gas and its critical temperature and pressure. Several graphical and analytical methods are available to calculate Z. Among these, the Standing-Katz, AGA and CNGA methods are quite popular. The critical temperature and the critical pressure of a gas are important parameters that affect the compressibility factor and are defined as follows.

The *critical temperature* of a pure gas is that temperature above which the gas cannot be compressed into a liquid, regardless of the pressure. The *critical pressure* is the minimum pressure required at the critical temperature of the gas to compress it into a liquid.

As an example, consider pure methane gas with a critical temperature of 343 ^{O}R and critical pressure of 666 psia. The *reduced temperature* of a gas is defined as the ratio of the gas temperature to its critical temperature, both being expressed in absolute units (^{O}R or K). It is therefore a dimensionless number.

Similarly, the *reduced pressure* is a dimensionless number defined as the ratio of the absolute pressure of gas to its critical pressure. Therefore we can state the following:

$$T_r = \frac{T}{T_c} \tag{1.10}$$

$$P_r = \frac{P}{P_c} \tag{1.11}$$

where:

P = pressure of gas, psia

T = temperature of gas, ^{O}R

T_r = reduced temperature, dimensionless

P_r = reduced pressure, dimensionless

T_c = critical temperature, ^{O}R

P_c = critical pressure, psia

Using the preceding equations, the reduced temperature and reduced pressure of a sample of methane gas at 70^{O}F and 1200 psia pressure can be calculated as follows:

$$T_r = \frac{70 + 460}{343} = 1.5452$$

and

$$P_r = \frac{1200}{666} = 1.8018$$

For natural gas mixtures, the terms *pseudo-critical temperature* and *pseudo-critical pressure* are used. The calculation methodology will be explained shortly. Similarly we can calculate the *pseudo-reduced* temperature and *pseudo-reduced pressure* of a natural gas mixture, knowing its *pseudo-critical temperature* and *pseudo-critical pressure*.

The Standing-Katz chart (Fig. 1.2_ can be used to determine the compressibility factor of a gas at any temperature and pressure, once the reduced pressure and temperature are calculated knowing the critical properties.

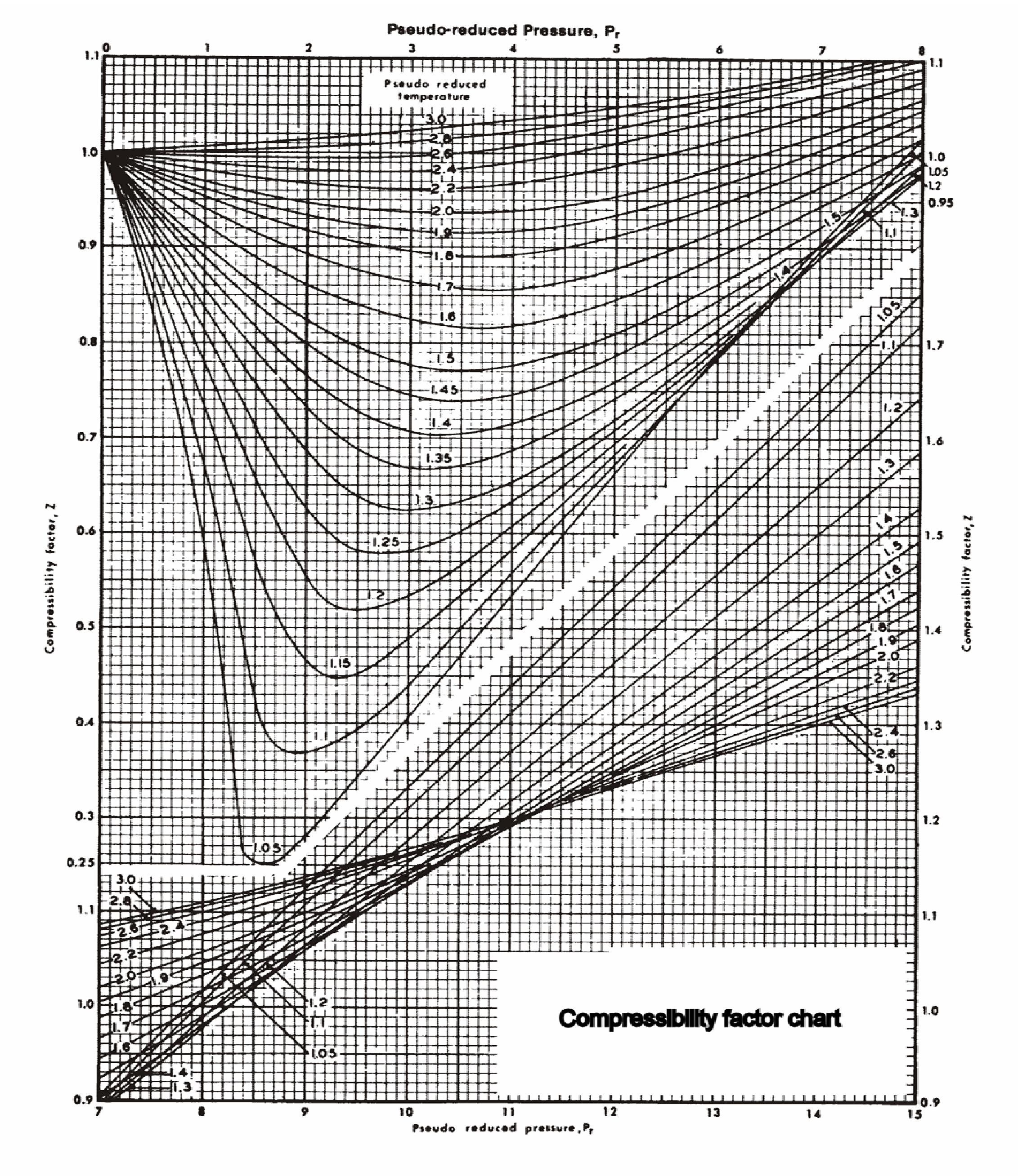

Fig. 1.2 Compressibility factor chart

Using the example above, the compressibility factor of the gas at 70 ^{O}F and 1200 psia is found from the Standing-Katz chart (Fig. 1.2) as Z = 0.850 approximately. Another analytical method of calculating the compressibility factor of a gas is using the CNGA equation as follows:

$$Z = \frac{1}{\left[1 + \left(\frac{P_{avg}\, 344400(10)^{1.785G}}{T_f^{3.825}}\right)\right]} \tag{1.12}$$

where:

P_{avg} = Gas pressure, psig.

T_f = Gas temperature, ^{O}R

G = Gas gravity (air = 1.00)

The CNGA equation for compressibility factor is valid when the average gas pressure P_{avg} is greater than 100 psig. For pressures less than 100 psig, compressibility factor is taken as 1.00. It must be noted that the pressure used in the CNGA equation is the gauge pressure, not the absolute pressure.

Example 1

Calculate the compressibility factor of a sample of natural gas (gravity = 0.6) at 80 ^{O}F and 1000 psig using the CNGA equation.

Solution

From the Eq. (1.12), the compressibility factor is:

$$Z = \frac{1}{\left[1 + \left(\frac{1000 \times 344400(10)^{1.785 \times 0.6}}{(80 + 460)^{3.825}}\right)\right]} = 0.8746$$

The CNGA method of calculating the compressibility, though approximate, is accurate enough for most gas pipeline hydraulics work.

The heating value of a gas is expressed in Btu/ft3. It represents the quantity of heat in Btu (British Thermal Unit) generated by the complete combustion of one cubic foot of the gas with air at constant pressure and a fixed temperature of 60 ^{O}F. Two values of the heating value of a gas are used: Gross heating value and Net heating value. The gross heating value is also called the higher heating value

(HHV) and the net heating value is called the lower heating value (LHV). The difference in the two values represents the latent heat of vaporization of the water at standard temperature when complete combustion of the gas occurs.

Natural gas mixtures

Natural gas generally consists of a mixture of several hydrocarbons, such as methane, ethane, etc. Methane is the predominant component in natural gas. Sometimes small amounts of non-hydrocarbon elements, such as nitrogen (N_2), carbon-dioxide (CO_2) and hydrogen sulfide (H_2S) are also found. The properties of a natural gas mixture can be calculated from the corresponding properties of the components in the mixture. Kay's rule is generally used to calculate the properties of a gas mixture, and will be explained next.

Example 2

A natural gas mixture consists of the following components:

Component	Percent	Molecular weight
Methane C_1	85	16.01
Ethane C_2	10	30.07
Propane C_3	5	44.10
Total	100	

Calculate the specific gravity of this natural gas mixture.

Solution

Using Kay's rule for a gas mixture, we can calculate the average molecular weight of the gas from the component molecular weights given. By dividing the molecular weight by the molecular weight of air, we can determine the specific gravity of the gas mixture. The average molecular weight per Kay's rule is calculated using a weighted average:

$$M = (0.85 \times 16.04) + (0.10 \times 30.07) + (0.05 \times 44.10) = 18.846$$

Therefore, the specific gravity of the gas mixture is using Eq. (1.6):

$$G = \frac{18.846}{29} = 0.6499$$

Example 3

Calculate the pseudo critical temperature and the pseudo critical pressure of a natural gas mixture containing 85 percent of methane (C_1), 10 percent ethane (C_2) and 5 percent propane (C_3). The critical temperatures and critical pressures of C_1, C_2 and C_3 are as follows:

Component	Critical Temperature, ^OR	Critical Pressure, psia
C_1	343	666
C_2	550	707
C_3	666	617

What is the reduced temperature and reduced pressure of this gas mixture at 80 ^OF and 1000 psia?

Solution

Kay's rule can be applied to calculate the pseudo-critical temperature and pseudo-critical pressure of the gas mixture from those of the component gases as follows:

T_{pc} = (0.85 x 343) + (0.10 x 550) + (0.05 x 666) = 379.85 ^OR, and

P_{pc} = (0.85 x 666) + (0.10 x 707) + (0.05 x 617) = 667.65 psia

Therefore, the pseudo critical properties of the gas mixture are:

pseudo-critical temperature = 379.85 ^OR, and

pseudo critical pressure = 667.65 psia

From Eq. (1.10) and Eq.(1.11), we calculate the pseudo-reduced temperature and the pseudo-reduced pressure as follows:

$$T_{pr} = \frac{80+460}{379.85} = 1.42$$

$$P_{pr} = \frac{1000}{667.65} = 1.498$$

Being ratios, both the above values are dimensionless.

If the gas composition is not known, the pseudo-critical properties may be calculated approximately from the gas gravity as follows:

$$T_{pc} = 170.491 + 307.344G \tag{1.13}$$

$$P_{pc} = 709.604 - 58.718G \tag{1.14}$$

where G is the gas gravity and other symbols are defined before.

Example 4

Calculate the pseudo critical temperature and pseudo critical pressure for a natural gas mixture containing 85 percent methane, 10 percent ethane and 5 percent propane, using the approximate method.

Solution

In Example 2, we calculated the gas gravity for this mixture as 0.6499. Using Eq. (1.13) and (1.14) the pseudo critical properties are calculated as follows:

T_{pc} = 170.491 + 307.344 x (0.6499) = 370.23 ^{O}R

P_{pc} = 709.604 - 58.718 x (0.6499) = 671.44 psia

In a previous example, we calculated the pseudo-critical properties using the more accurate method as 379.85 ^{O}R and 667.65 psia. Comparing these with the approximate method using the gas gravity, we find that the values are within 2.5 percent for the pseudo critical temperature and within 0.6 percent for the pseudo critical pressure.

Gas Laws

The compressibility of a gas was introduced earlier and we defined it as a dimensionless number close to 1.0 that also represents how far a real gas deviates from an ideal gas. Ideal gases or perfect gases obey Boyles and Charles law and have pressure, temperature and volume related by the ideal gas equation. These laws for ideal gases are as follows:

Boyles Law defines the variation of pressure of a given mass of gas with its volume when the temperature is held constant. The relationship between pressure P and volume V is

$$PV = \text{constant} \quad (1.15)$$

Or

$$P_1V_1 = P_2V_2 \quad (1.16)$$

where P_1, V_1 are the initial conditions and P_2, V_2 are the final conditions of a gas when temperature is held constant. This is also called isothermal conditions.

Boyles law applies only when the gas temperature is constant. Thus if a given mass of gas has an initial pressure of 100 psia and a volume of 10 ft^3, with the temperature remaining constant at 80 ^{O}F and the pressure increases to 200 psia, the corresponding volume of gas becomes:

Final volume = $\frac{100 \times 10}{200} =$ 5 ft^3

Charles law applies to variations in pressure-temperature and volume-temperature, when the volume and pressures are held constant. Thus keeping the volume constant, the pressure versus temperature relationship according to Charles law is as follows:

$$\frac{P}{T} = \text{constant} \quad (1.17)$$

Or

$$\frac{P_1}{T_1} = \frac{P_2}{T_2} \quad (1.18)$$

Similarly if the pressure is held constant, the volume varies directly as the temperature as follows:

$$\frac{V}{T} = \text{constant} \quad (1.19)$$

Or

$$\frac{V_1}{T_1} = \frac{V_2}{T_2} \quad (1.20)$$

where P_1, V_1 and T_1 are the initial conditions and P_2, V_2 and T_2 are the final conditions. It must be noted that pressures and temperatures must be in absolute units.

Example 5

A given mass of gas is at an initial condition of 80 ^OF, 100 psia and 10 ft^3. If the final conditions are 100 psia and 100 ^OF, what is the final gas volume?

Solution

Since the pressure remains constant, we can apply Charles law (Eq. 1.20) as follows:

$$\frac{10}{80+460} = \frac{V_2}{100+460}$$

Solving for the final volume, V_2

V_2 = 10.37 ft^3

The Ideal Gas equation, or the Perfect Gas equation, as it is sometimes called combines Boyle's law and Charles law and is stated as follows:

$$PV = nRT \tag{1.21}$$

where:

P = gas pressure, psia

V = gas volume, ft^3

n = number of lb moles of gas (mass/molecular weight)

R = universal gas constant, psia ft^3/lb mole ^OR

T = gas temperature, ^OR

The universal gas constant R is equal to 10.73 psia ft^3/lb mole ^OR in USCS units. If m is the mass of gas and M its molecular weight, then:

$$n = \frac{m}{M} \tag{1.22}$$

Therefore, the ideal gas equation becomes:

$$PV = \frac{mRT}{M} \tag{1.23}$$

The constant R is the same for all ideal gases and therefore it is referred to as the universal gas constant. The ideal gas equation discussed above is accurate only at low pressures. Because, in practice most gas pipelines operate at pressures higher than atmospheric pressures, the ideal gas equation must be modified when applied to real gases by including the effect of gas compressibility. Thus, when applied to real gases, the compressibility factor or gas deviation factor is used in Eq. (1.21) as follows:

$$PV = ZnRT \tag{1.24}$$

where Z is the gas compressibility factor at the given pressure and temperature.

Example 6

Calculate the volume of a 10 lb mass of gas (Gravity = 0.6) at 500 psig and 80 ^{O}F, assuming the compressibility factor as 0.895. The molecular weight of air may be taken as 29 and the base pressure is 14.7 psia.

Solution

The number of lb moles n is calculated using Eq. (1.22). The molecular weight of the gas:

M = 0.6 x 29 = 17.4

Therefore, $n = \frac{10}{17.4} = 0.5747$ lb mole

Using the real gas Eq. (1.24):

(500 + 14.7) V = 0.895 x 0.5747 x 10.73 x (80 + 460)

Therefore, V = 5.79 ft^3

2. Pressure Drop Due To Friction

The Bernoulli's equation essentially states the principle of conservation of energy. In a flowing fluid (gas or liquid) the total energy of the fluid remains constant. The various components of the fluid energy are transformed from one form to another, but no energy is lost as the fluid flows in a pipeline. Consider an upstream location A and downstream location B in a pipe transporting a gas, at a flow rate of Q as shown in Fig. 2.1

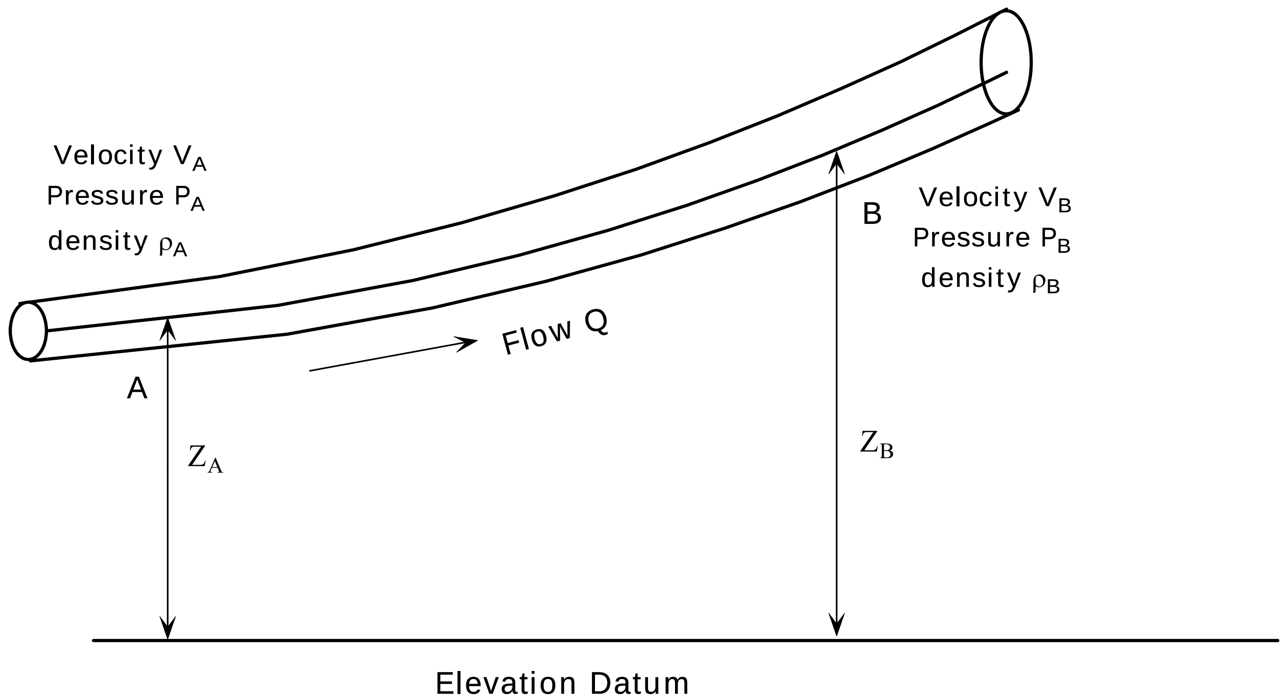

Fig 2.1 Energy of gas in pipe flow

At point A, the gas has a certain pressure P_A, density ρ_A, and temperature T_A. Also the elevation of point A above a certain datum is Z_A. Similarly, the corresponding values for the downstream location B are P_B, ρ_B, T_B and Z_B. If the pressures and elevations at A and B were the same, there would be no "driving force" and hence no gas flow. Due to the difference in pressures and elevations, gas flows from point A to point B. The reason for the pressure difference in a flowing gas is partly due to the elevation difference and more due to the friction between the flowing gas and the pipe wall. As the internal roughness of the pipe increases the friction increases. The velocity of the gas, which is proportional to the volume flow rate

Q, also changes depending upon the cross sectional area of the pipe and the pressures and temperature of the gas. By the principle of conservation of mass, the same mass of gas flows at A as it does at B, if no volumes of gas are taken out or introduced into the pipe between points A and B. Therefore, if V_A and V_B represent the gas velocities at points A and B, we can state the following for the principle of conservation of mass.

$$\text{Mass flow} = A_A V_A \rho_A = A_B V_B \rho_B \qquad (2.1)$$

In the above equation the product of the area A and Velocity V represents the volume flow rate, and by multiplying the result by the density ρ, we get the mass flow rate at any cross section of the pipe. If the pipe cross section is the same throughout (constant diameter pipeline), the mass flow equation reduces to:

$$V_A \rho_A = V_B \rho_B \qquad (2.2)$$

Referring to Fig 2.1, for the flow of gas in a pipeline, the energy of a unit mass of gas at A may be represented by the following three components:

Pressure energy $\dfrac{P_A}{\rho_A}$ (2.3)

Kinetic energy $\dfrac{{V_A}^2}{2g}$ (2.4)

Potential energy Z_A (2.5)

All energy components have been converted to units of fluid head in feet and g is the acceleration due to gravity. Its value at sea level is 32.2 ft/s^2 in USCS units and 9.81 m/s^2 in SI units.

If the frictional energy loss (in ft of head) in the pipeline from point A to point B is h_f, we can write the energy conservation equation or the Bernoulli's equation as follows:

$$\frac{P_A}{\rho_A} + \frac{V_A^2}{2g} + Z_A = \frac{P_B}{\rho_B} + \frac{V_B^2}{2g} + Z_B + h_f \qquad (2.6)$$

The term h_f is also called the pressure loss due to friction between points A and B. Starting with the Bernoulli's equation, researchers have developed a formula for calculating the pressure drop in a gas pipeline, taking into account the pipe diameter, length, elevations along the pipe, gas flow rate and the gravity and compressibility of the gas. This basic equation is referred to the Fundamental Flow Equation, also known as the General Flow equation.

As gas flows through a pipeline, its pressure decreases and the gas expands. In addition to the gas properties, such as gravity and viscosity, the pipe inside diameter and pipe internal roughness influence the pressure versus flow rate. Since the volume flow rate Q can vary with the gas pressure and temperature, we must refer to some standard volume flow rate, based on standard conditions, such as 60 ^{O}F and 14.7 psia pressure. Thus the gas flow rate Q will be referred to as standard ft^3/day or SCFD. Variations of this are million standard ft^3/day or MMSCFD and standard ft^3/h or SCFH. In SI units, the gas flow rate in a pipeline is stated in standard m^3/hr or standard m^3/day.

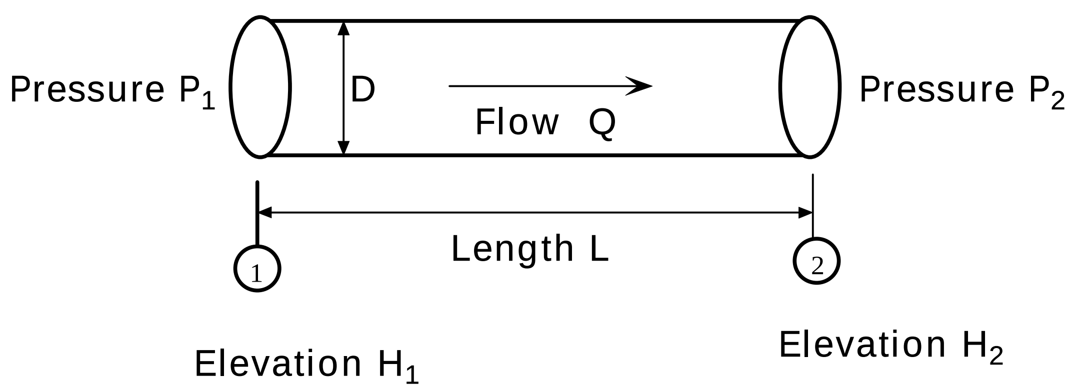

Fig 2.2 Steady state flow in a gas pipeline

Referring to Fig 2.2, for a pipe segment of length L and inside diameter D, the upstream pressure P_1 and the downstream pressure P_2 are related to the flow rate and gas properties (based on USCS units) as follows:

$$Q = 77.54\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - P_2^2}{GT_f LZf}\right)^{0.5} D^{2.5} \tag{2.7}$$

where:

Q = gas flow rate, standard, ft^3/day (SCFD)

L = pipe length, mi

D = inside diameter pf pipe, in.

P_1 = upstream pressure, psia.

P_2 = downstream pressure, psia.

P_b = base pressure, psia (usually 14.7 psia)

T_b = base temperature, ^{O}R (usually 60+460 = 540 ^{O}R)

T_f = average flowing temperature of gas, ^{O}R

G = gas specific gravity (Air = 1.00)

Z = gas compressibility factor at the flowing temperature and pressure, dimensionless

f = friction factor, dimensionless

The General Flow Equation in SI units is as follows:

$$Q = 1.1494 \times 10^{-3}\left(\frac{T_b}{P_b}\right)\left[\frac{\left(P_1^2 - P_2^2\right)}{GT_f LZf}\right]^{0.5} D^{2.5} \tag{2.8}$$

where:

Q = gas flow rate, standard, ft^3/day (m^3/day)

L = pipe length, km

D = inside diameter pipe, mm.

P_1 = upstream pressure, kPa (absolute).

P_2 = downstream pressure, kPa (absolute).

P_b = base pressure, kPa (absolute).

T_b = base temperature, K

T_f = average flowing temperature of gas, K

G = gas specific gravity (air = 1.00)

Z = gas compressibility factor at the flowing temperature and pressure, dimensionless

f = friction factor, dimensionless

The pressures in the above equation may also be in MPa or Bar as long as the same consistent units are used throughout. Always use absolute pressures, not gauge pressures.

In the preceding equations, we have assumed that for the pipe segment of length L, from upstream point 1 to the downstream point 2, the flowing gas temperature (T_f) is constant. In other words, isothermal flow is assumed. This may not be true in reality, since there will be heat transfer between the gas in the pipeline and the surrounding soil if the pipe is buried. If the pipe is above ground the heat transfer will be between the gas and the ambient air. In any case, for simplicity, we will assume that there is isothermal gas flow in the pipeline. The friction factor f in Eq. (2.8) is referred to as the Darcy friction factor and depends upon the internal condition (rough or smooth) of the pipe and whether the flow is laminar or turbulent. Laminar and turbulent flow, along with the Reynolds number will be discussed shortly. The value of f is generally determined graphically from the Moody diagram (Fig. 2.3) or analytically from the Colebrook-White equation as will be explained in the next section.

Effect of pipe elevations

So far, we have neglected the effect of elevation difference between the upstream and downstream locations of the pipe. If the elevations H_1 and H_2 are included, the General Flow equation becomes as follows:

$$Q = 77.54\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{G T_f L_e Z f}\right)^{0.5} D^{2.5} \qquad (2.9)$$

where the equivalent length L_e and the term e^s depend upon the elevation difference (H_2 - H_1).

In SI units, the corrected equation is:

$$Q = 1.1494\times10^{-3}\left(\frac{T_b}{P_b}\right)\left[\frac{\left(P_1^2 - e^s P_2^2\right)}{G T_f L Z f}\right]^{0.5} D^{2.5} \qquad (2.10)$$

The term L_e and e^s are related as follows:

$$L_e = \frac{L(e^s - 1)}{s} \tag{2.11}$$

The dimensionless, elevation adjustment parameter s varies with the gas properties, the gas flowing temperature and the elevation difference. It is calculated as follows:

$$s = 0.0375G\left(\frac{H_2 - H_1}{T_f Z}\right) \tag{2.12}$$

where:

s = elevation adjustment parameter, dimensionless

H_1 = upstream elevation, ft

H_2 = downstream elevation, ft

In SI units the corresponding equation is:

$$s = 0.0684G\left(\frac{H_2 - H_1}{T_f Z}\right) \tag{2.13}$$

where H_1 and H_2 are expressed in meters.

The General Flow equation can be used for calculating the flow rate in a gas pipeline, given the upstream and downstream pressures. Alternatively, it can be used to calculate the pressure drop for a given flow rate. This is illustrated in the example below

Example 7

Calculate the flow rate through a 10 mile long gas pipeline, NPS 20, 0.375 inch wall thickness, transporting gas, with a gravity of 0.6 and a compressibility factor of 0.85. The inlet and outlet pressures are 1000 psig and 800 psig respectively. Base temperature and pressure are 60 ^{O}F and 14.7 psia. Gas flowing temperature is 70 ^{O}F. Neglect elevation effects and assume friction factor f = 0.02

Solution

The inside diameter of the pipe is:

D = 20 – 2 x 0.375 = 19.25 in.

The gas flowing temperature is:

T_f = 70+460 = 530 R

Using the General Flow equation (2.7), we get"

$$Q = 77.54\left(\frac{60+460}{14.7}\right)\left(\frac{1014.7^2 - 814.7^2}{0.6\times 530\times 10\times 0.85\times 0.02}\right)^{0.5} 19.25^{2.5}$$

Therefore, Q = 380,987,188 SCFD or 380.99 MMSCFD

Another form of the General Flow equation uses the transmission factor F instead of the friction factor f. These parameters are related by the equation:

$$F = \frac{2}{\sqrt{f}} \tag{2.14}$$

From Eq (2.14) we see that if the friction factor f = 0.02, the transmission factor F = 14.14. Thus while the friction factor is a number less than 1.00, the transmission factor is a number between 10 and 20. Using the transmission factor F instead of the friction factor f, and considering the elevation difference, the General Flow equation (2.9) becomes:

$$Q = 38.77F\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.5} \tag{2.15}$$

The corresponding equation in SI units is:

$$Q = 5.747\times 10^{-4} F\left(\frac{T_b}{P_b}\right)\left[\frac{\left(P_1^2 - e^s P_2^2\right)}{GT_f L_e Z}\right]^{0.5} D^{2.5} \tag{2.16}$$

Upon examining the General Flow equation, we see that the gas flow rate in a pipeline is approximately proportional to the square root of difference in squares of the upstream and downstream pressures, or $\sqrt{\left(P_1^2 - P_2^2\right)}$. In comparison, in liquid flow through pipes, the flow rate is directly proportional to the square root of the pressure difference or $\sqrt{\left(P_1 - P_2\right)}$. This is a very important feature of gas flow in pipes. The result of this is that the pressure gradient in a gas pipeline is slightly curved, compared to a straight line in liquid flow. Also in a gas pipeline, reduction in upstream or downstream pressure at the same flow rate will not be reflected to the same extent throughout the pipeline, unlike liquid flow. Suppose the upstream pressure and downstream pressures are 1000 and 800 psia, respectively, at a certain flow rate in a gas pipeline. By keeping the flow rate the same, a 100 psia reduction in upstream pressure will not result in exactly 100 psia reduction in the downstream pressure, due to the Q versus $\sqrt{\left(P_1^2 - P_2^2\right)}$ relationship in gas flow. In a liquid pipeline, on the other hand, a 100 psia reduction in upstream pressure will result in exactly 100 psia reduction in the downstream pressure.

Other interesting observations from the General Flow equation are as follows. The higher the gas gravity and compressibility factor, the lower will be the flow rate, other items remaining the same. Similarly, the longer the pipe segment, the lower will be the gas flow rate. Obviously, the larger the pipe diameter, the greater will be the flow rate. Hotter gas flowing temperature causes reduction in flow rate. This is in stark contrast to liquid flow in pipes where the higher temperature causes reduction in the liquid gravity and viscosity, and hence increase the flow rate for a given pressure drop. In gas flow, we find that cooler temperatures cause increase in flow rate. Thus summer flow rates are lower than winter flow rates in gas pipelines.

Several other flow equations or pressure drop formulas for gas flow in pipes are commonly used. Among these Panhandle A, Panhandle B and Weymouth equations have found their place in the gas pipeline industry. The General Flow equation however is the most popular one and the friction factor f is calculated by either using the Colebrook equation or the AGA formulas. Before we discuss the other flow equations, we will review the different types of flows, Reynolds number and how the friction factor is calculated using the Colebrook-White equation or the AGA method.

The flow through a pipeline may be classified as laminar, turbulent or critical flow depending upon the value of a dimensionless parameter called the Reynolds number. The Reynolds number depends upon the gas properties, pipe diameter and flow velocity and is defined as follows:

$$\mathrm{Re} = \frac{VD\rho}{\mu} \tag{2.17}$$

where:

Re = Reynolds number, dimensionless

V = average gas velocity, ft/s

D = pipe inside diameter, ft

ρ = gas density, lb/ft^3

μ = gas viscosity, lb/ft-s

In terms of the more commonly used units in the gas pipeline industry, the following formula for Reynolds number is more appropriate, in USCS units:

$$\mathrm{Re} = 0.0004778\left(\frac{P_b}{T_b}\right)\left(\frac{GQ}{\mu D}\right) \tag{2.18}$$

where:

P_b = base pressure, psia

T_b = base temperature, ^{O}R

G = gas specific gravity

Q = gas flow rate, standard ft^3/day (SCFD)

D = pipe inside diameter, in.

μ = gas viscosity, lb/ft-s

The corresponding version in SI units is as follows:

$$\mathrm{Re} = 0.5134\left(\frac{P_b}{T_b}\right)\left(\frac{GQ}{\mu D}\right) \tag{2.19}$$

where:

P_b = base pressure, kPa

T_b = base temperature, K

G = gas specific gravity

Q = gas flow rate, standard m^3/day

D = pipe inside diameter, mm

μ = gas viscosity, Poise

The flow in a gas pipeline is considered to be laminar flow when the Reynolds number is below 2000. Turbulent flow is said to exist when the Reynolds number is greater than 4000. When the Reynolds numbers is between 2000 and 4000, the flow is called critical flow, or undefined flow.

Therefore,

	Re <= 2000	Flow is laminar
	Re > 4000	Flow is turbulent
And	Re > 2000 and Re <= 4000	Flow is critical flow

In practice, most gas pipelines operate at flow rates that produce high Reynolds numbers, and therefore in the turbulent flow regime. Actually, the turbulent flow regime is further divided into three regions known as smooth pipe flow, fully rough pipe flow and transition flow. This is illustrated in the Moody diagram shown in Fig 2.3 below.

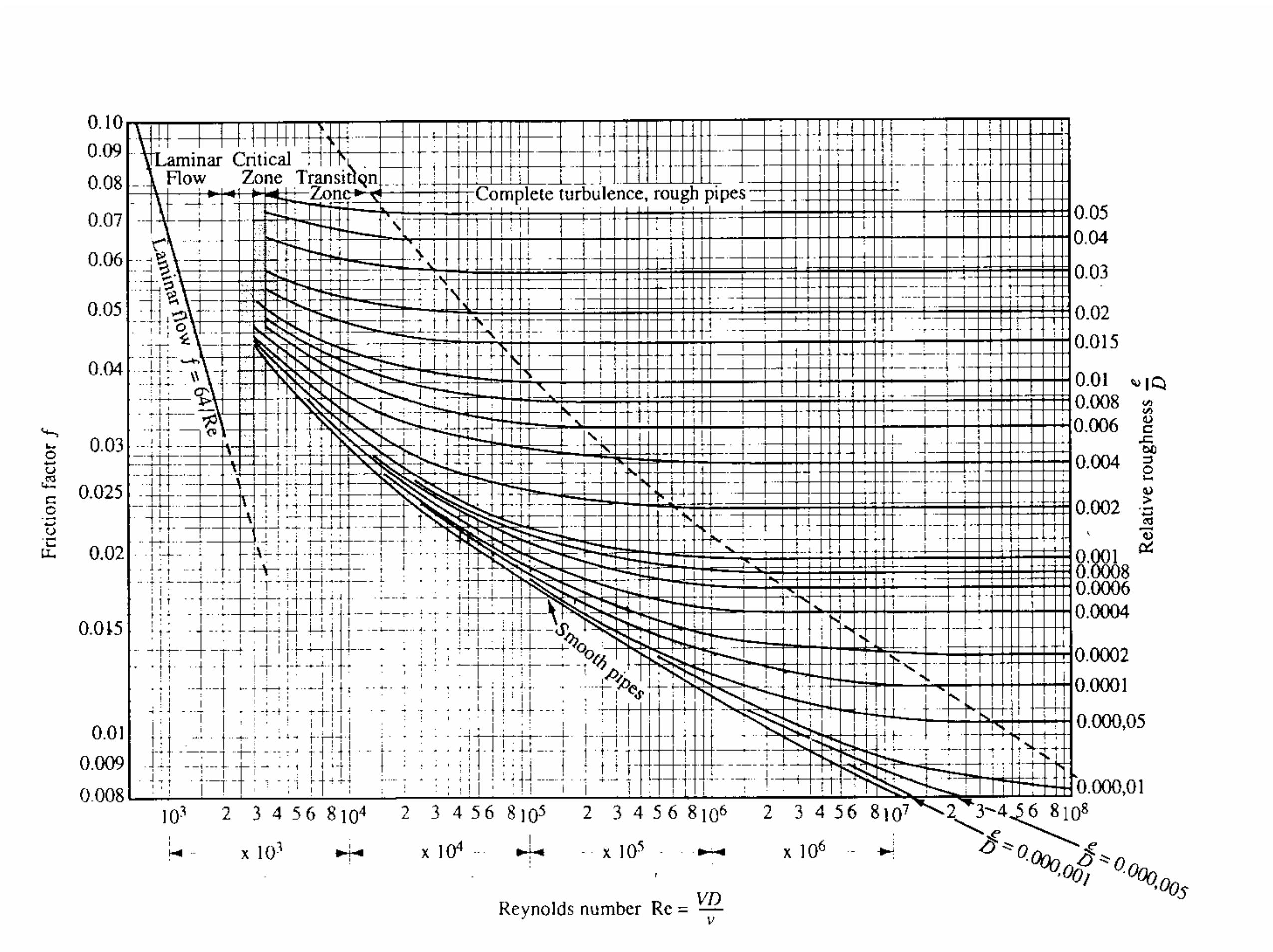

Fig. 2.3 Moody diagram

When the flow is laminar, the friction factor f, used in the General Flow equation is calculated easily from the following equation:

$$f = \frac{64}{\mathrm{Re}} \tag{2.20}$$

Therefore, if the Reynolds number is 1800, the friction factor becomes:

$$f = \frac{64}{1800} = 0.0356$$

When the flow is turbulent, the friction factor depends not only on the Reynolds number, but also on the inside diameter of the pipe and the internal pipe roughness. Obviously, the friction factor is higher with rougher pipe, compared to a smooth pipe. The popular equation known as the Colebrook-White equation, sometimes simply called the Colebrook equation, can be used to calculate the friction factor for turbulent flow as follows:

$$\frac{1}{\sqrt{f}} = -2Log_{10}\left(\frac{e}{3.7D} + \frac{2.51}{\mathrm{Re}\sqrt{f}}\right) \tag{2.21}$$

where:

f = friction factor, dimensionless

D = pipe inside diameter, in.

e = absolute internal roughness of pipe, in.

Re = Reynolds number of flow, dimensionless

The dimensionless ratio $\frac{e}{D}$ is also known as the relative roughness of pipe.

The absolute roughness e varies with the internal condition of the pipe. For bare steel pipe a roughness value of 0.0007 inch (700 micro-inches) may be used. For internal coated pipe e ranges from 100 to 300 micro-inches. It can be seen from Eq. (2.21) that the calculation of the friction factor f from the Colebrook-White equation is not straightforward. It requires a trial and error solution since f appears on both sides of the equation. First an initial value of f (such as f = 0.02) is assumed and substituted on the right hand side of Eq. (2.21). This gives us a new approximation for f, which is then substituted on the right hand side of the equation resulting in a better approximation, and so on. Three or four trials will yield a fairly accurate value of f. This will be illustrated in the example below.

First we will illustrate the calculation of the friction factor using the Moody diagram. Suppose the Reynolds number calculated is Re = 2 million and the relative roughness e/D = 0.0004. Using these two values, we go to the Moody diagram and locate the 2 million number on the horizontal scale. Going vertically from that point until we reach the curves of constant relative roughness, we locate the curve for e/D = 0.0004.

From the point of intersection, we go horizontally to the left and read the value of the friction factor f as f = 0.016.

In the next example, the calculation of f using the Colebrook equation will be explained.

Example 8

A gas pipeline, NPS 24 with 0.500 in. wall thickness transports 250 MMSCFD of natural gas having a specific gravity of 0.65 and a viscosity of 0.000008 lb/ft-s. Calculate the value of Reynolds number and the Colebrook-White friction factor, based on a pipe roughness of 700 micro-inches. The base temperature and base pressure are 60 ^{O}F and 14.73 psia, respectively. What is the corresponding transmission factor F?

Solution

Inside diameter of pipe = 24 – 2 x 0.5 = 23.0 in.

Base temperature = 60 + 460 = 520 ^{O}R

Using Eq. (2.18), the Reynolds number is:

$$\mathrm{Re} = 0.0004778\left(\frac{14.73}{520}\right)\left(\frac{0.65\times 250\times 10^{6}}{0.000008\times 23}\right) = 11{,}953{,}115$$

Therefore the flow is in the turbulent region.

From Eq. (2.21), we calculate the friction factor as follows:

Relative roughness = $\frac{e}{D} = \frac{700\times 10^{-6}}{23} = 0.0000304$

$$\frac{1}{\sqrt{f}} = -2Log_{10}\left(\frac{0.0000304}{3.7} + \frac{2.51}{11{,}953{,}115\sqrt{f}}\right)$$

First assume f = 0.02 and calculate a better approximation from above as:

$$\frac{1}{\sqrt{f}} = -2Log_{10}\left(\frac{0.0000304}{3.7} + \frac{2.51}{11{,}953{,}115\sqrt{0.02}}\right) = 10.0264 \text{ or } f = 0.0099$$

Therefore f = 0.0099 is a better approximation.

Next using this value, we get the next better approximation as:

$$\frac{1}{\sqrt{f}} = -2Log_{10}\left(\frac{0.0000304}{3.7} + \frac{2.51}{11{,}953{,}115\sqrt{0.0099}}\right)$$

Solving for f we get f = 0.0101. The next trial yields f = 0.0101, which is the same as the last calculated value. Hence the solution for the friction factor is f = 0.0101. The corresponding transmission factor F is calculated from Eq. (2.14) as:

$$F = \frac{2}{\sqrt{0.0101}} = 19.95$$

Another popular correlation for the transmission factor (and hence the friction factor) is the AGA equation. It is also referred to as the AGA NB-13 method. Using the AGA method, the transmission factor F is calculated in two steps. First the transmission factor is calculated for the rough pipe law. Next F is calculated based upon the smooth pipe law. These two zones refer to the Moody diagram discussed earlier. The smaller of the two values calculated is the AGA transmission factor. This factor is then used in the General Flow equation to calculate the pressure drop. The method of calculation is as follows:

Using the rough pipe law, AGA recommends the following formula for F for a given pipe diameter and roughness. It is calculated independent of the Reynolds number.

$$F = 4Log_{10}\left(\frac{3.7D}{e}\right) \qquad (2.22)$$

This calculation for the rough pipe regime is also called the Von Karman rough pipe flow equation.

Next, F is calculated for the partially turbulent zone using the following equations, taking into account the Reynolds number, the pipe drag factor and the Von Karman smooth pipe transmission factor F_t.

$$F = 4D_f Log_{10}\left(\frac{\mathrm{Re}}{1.4125F_t}\right) \qquad (2.23)$$

and

$$F_t = 4Log_{10}\left(\frac{\text{Re}}{F_t}\right) - 0.6 \quad (2.24)$$

where:

F_t = Von Karman smooth pipe transmission factor

D_f = pipe drag factor

The value of F_t must be calculated from Eq. (2.24) by trial and error. The pipe drag factor D_f is a dimensionless parameter that is a function of the Bend Index (BI) of the pipe. The bend index depends upon the number of bends and fittings in the pipe. The BI is calculated by adding all the angles and bends in the pipe segment, and dividing the total by the total length of the pipe segment. The drag factor D_f generally ranges between 0.90 and 0.99 and can be found from Table 1 below.

Table 1 – Bend Index and Drag Factor

	Bend Index		
	Extremely low 5^o to 10^o	Average 60^o to 80^o	Extremely high 200^o to 300^o
Bare steel	0.975 - 0.973	0.960 - 0.956	0.930 - 0.900
Plastic lined	0.979 - 0.976	0.964 - 0.960	0.936 - 0.910
Pig Burnished	0.982 - 0.980	0.968 - 0.965	0.944 - 0.920
Sand-Blasted	0.985 - 0.983	0.976 - 0.970	0.951 - 0.930

Note: The drag factors above are based on 40 ft joints of pipelines and mainline valves at 10 mile spacing

Additional data on the bend index and drag factor may be found in the AGA NB-13 Committee Report. An example using the AGA transmission factor will be illustrated in the example below.

Example 9

A natural gas pipeline NPS 24 with 0.500 in. wall thickness transport gas at 250 MMSCFD. Calculate the AGA transmission factor and friction factor. The gas gravity and viscosity are 0.59 and 0.000008 lb/ft-sec, respectively. Assume an absolute pipe roughness of 750 micro-inches and a bend index of 60^o. Given base pressure = 14.7 psia and base temperature = 60 ^{O}F.

Solution

Pipe inside diameter = 24 – 2 x 0.5 = 23.0 in.

Base temperature = 60 + 460 = 520 ^{O}R

First calculate the Reynolds number from Eq. (2.18):

$$\mathrm{Re} = \frac{0.0004778 \times 250 \times 10^6 \times 0.59 \times 14.7}{23.0 \times 0.000008 \times 520} = 10{,}827{,}653$$

Next we will calculate the transmission factor for the fully turbulent flow using the rough pipe law Eq. (2.22):

$$F = 4 Log_{10}\left(\frac{3.7 \times 23.0}{0.00075}\right) = 20.22$$

Next, for the smooth pipe zone, the Von Karman transmission factor is calculated from Eq. (2.24) as:

$$F_t = 4 Log_{10}\left(\frac{10{,}827{,}653}{F_t}\right) - 0.6$$

Solving for F_t by trial and error, Ft = 22.16.

The bend index of 60^{o} gives a drag factor D_f of 0.96, from Table 1.

Therefore, the transmission factor for the partially turbulent flow zone is from Eq. (2.23):

$$F = 4 \times 0.96 Log_{10}\left(\frac{10{,}827{,}653}{1.4125 \times 22.16}\right) = 21.27$$

Therefore, choosing the smaller of the two values calculated above, the AGA transmission factor is:

F = 20.22

The corresponding friction factor f is found from Eq. (2.14):

$$\frac{2}{\sqrt{f}} = 20.22$$

Therefore, f = 0.0098

Average pipeline pressure

The gas compressibility factor Z used in the General Flow equation is based upon the flowing temperature and the average pipe pressure. The average pressure may be approximated as the arithmetic average $\frac{P_1 + P_2}{2}$ of the upstream and downstream pressures P_1 and P_2. However, a more accurate average pipe pressure is usually calculated as follows:

$$P_{avg} = \frac{2}{3}\left(P_1 + P_2 - \frac{P_1 P_2}{P_1 + P_2} \right) \tag{2.25}$$

The preceding equation may also be written as:

$$P_{avg} = \frac{2}{3}\left(\frac{P_1^{\ 3} - P_2^{\ 3}}{P_1^{\ 2} - P_2^{\ 2}} \right) \tag{2.26}$$

Since the pressures used in the General Flow equation are in absolute units, all gauge pressures must be converted to absolute pressures, when calculating the average pressure from Eq. (2.25) and (2.26). As an example, if the upstream and downstream pressures are 1200 psia and 1000 psia respectively, the average pressure in the pipe segment is:

$$P_{avg} = \frac{2}{3}\left(1200 + 1000 - \frac{1200 \times 1000}{2200} \right) = 1103.03 \text{ psia}$$

If we used the arithmetic average, this becomes:

$$P_{avg} = \frac{1}{2}(1200 + 1000) = 1100 \text{ psia}$$

Velocity of gas in pipe flow

The velocity of gas flow in a pipeline under steady state flow can be calculated by considering the volume flow rate and pipe diameter. In a liquid pipeline, under steady flow, the average flow velocity remains constant throughout the pipeline, as long as the inside diameter does not change. However, in a gas pipeline, due to compressibility effects, pressure variation and temperature variation, the average gas velocity will vary along the pipeline even if the pipe inside diameter remains the same. The average velocity in a gas pipeline at any location along the pipeline is a function of the flow rate, gas compressibility factor, pipe diameter, pressure and temperature, as indicated in the equation below:

$$V = 0.002122\left(\frac{P_b}{T_b}\right)\left(\frac{Z\ T}{P}\right)\left(\frac{Q_b}{D^2}\right) \qquad (2.27)$$

where:

V = Average gas velocity, ft/s

Q_b = gas flow rate, standard ft^3/day (SCFD)

D = inside diameter of pipe, in.

P_b = base pressure, psia

T_b = base temperature, ^{O}R

P = gas pressure, psia.

T = gas temperature, ^{O}R

Z = gas compressibility factor at pipeline conditions, dimensionless

It can be seen from the velocity equation that the higher the pressure, the lower the velocity and vice versa. The corresponding equation for the velocity in SI units is as follows:

$$V = 14.7349\left(\frac{P_b}{T_b}\right)\left(\frac{ZT}{P}\right)\left(\frac{Q_b}{D^2}\right) \qquad (2.28)$$

where:

V = gas velocity, m/s

Q_b = gas flow rate, standard m^3/day

D = inside diameter of pipe, mm

P_b = base pressure, kPa

T_b = base temperature, K

P = gas pressure, kPa.

T = gas temperature, K

Z = gas compressibility factor at pipeline conditions, dimensionless

In the SI version of the equation, the pressures may be in any one consistent set of units, such as kPa, MPa or Bar.

Erosional velocity

The erosional velocity represents the upper limit of gas velocity in a pipeline. As the gas velocity increases, vibration and noise result. Higher velocities also cause erosion of the pipe wall over a long time period. The erosional velocity V_{max} may be calculated approximately as follows:

$$V_{\max} = 100\sqrt{\frac{ZRT}{29GP}} \qquad (2.29)$$

where:

Z = gas compressibility factor, dimensionless

R = gas constant = 10.73 ft^3 psia/lb-moleR

T = gas temperature, ^0R

G = gas gravity (air = 1.00)

P = gas pressure, psia

Example 10

A natural gas pipeline NPS 20 with 0.500 in. wall thickness transports natural gas (specific gravity = 0.65) at a flow rate of 200 MMSCFD at an inlet temperature of 70 ^OF. Calculate the gas velocity at inlet and outlet of the pipe, assuming isothermal flow. The inlet pressure is 1200 psig and the outlet pressure is 900 psig. The base pressure is 14.7 psia and the base temperature is 60 ^OF. Use average compressibility factor of 0.95. Also, calculate the erosional velocity for this pipeline.

Solution

From Eq. (2.27) the gas velocity at the pipe inlet pressure of 1200 psig is:

$$V_1 = 0.002122 \left(\frac{200 \times 10^6}{19.0^2}\right)\left(\frac{14.7}{60 + 460}\right)\left(\frac{70 + 460}{1214.7}\right) \times 0.95$$

= 13.78 ft/s

Similarly, the gas velocity at the outlet pressure of 900 psig can be calculated using proportions from Eq. (2.27):

$$V_2 = 13.78 \times \frac{1214.7}{914.7}$$ = 18.30 ft/s

Finally, the erosional velocity can be calculated using Eq. (2.29):

$$u_{\max} = 100\sqrt{\frac{0.95 \times 10.73 \times 530}{29 \times 0.65 \times 1214.7}}$$ = 48.57 ft/s

Weymouth Equation

The Weymouth equation is used for calculating flows and pressures in high pressure gas gathering systems. It does not use a friction factor or a transmission factor directly, but uses a pipeline efficiency factor. However, we can calculate the transmission factor by comparing the Weymouth equation with the General Flow equation. The Weymouth equation, in USCS units, is as follows:

$$Q = 433.5E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.667} \tag{2.30}$$

where E is the pipeline efficiency, expressed as a decimal value less than or equal to 1.0.

All other terms have been defined previously under the General Flow equation. Comparing the Weymouth equation with General Flow equation, the Weymouth transmission factor in USCS units may be calculated from the following equation:

$$F = 11.18(D)^{1/6} \tag{2.31}$$

In SI units, the Weymouth equation is expressed as follows:

$$Q = 3.7435 \times 10^{-3} E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{GT_f L_e Z}\right)^{0.5} D^{2.667} \tag{2.32}$$

where all symbols have been defined previously.

In SI units, the corresponding Weymouth transmission factor is:

$$F = 6.521 (D)^{1/6} \tag{2.33}$$

Panhandle Equations

The Panhandle A and the Panhandle B Equations have been used by many natural gas pipeline companies, including a pipeline efficiency factor, instead of considering the pipe roughness. These equations have been successfully used for Reynolds numbers in the range of 4 million to 40 million.

The more common versions of Panhandle A equation is as follows:

$$Q = 435.87E\left(\frac{T_b}{P_b}\right)^{1.0788}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8539}T_f L_e Z}\right)^{0.5394} D^{2.6182} \tag{2.34}$$

where E is the pipeline efficiency, a decimal value less than 1.0, and all other symbols have been defined before under General Flow equation.

In SI Units, the Panhandle A equation is stated as follows:

$$Q = 4.5965\times 10^{-3}E\left(\frac{T_b}{P_b}\right)^{1.0788}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8539}T_f L_e Z}\right)^{0.5394} D^{2.6182} \tag{2.35}$$

All symbols have been previously defined. It must be noted that in the preceding SI version, all pressures are in kPa. If MPa or Bar is used, the constant in Eq.(2.35) will be different.

The Panhandle B equation, sometimes called the revised Panhandle equation, is used by many gas transmission companies. It is found to be fairly accurate in turbulent flow for Reynolds numbers between 4 million and 40 million. It is expressed as follows, in USCS units:

$$Q = 737E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.961}T_f L_e Z}\right)^{0.51} D^{2.53} \tag{2.36}$$

where all symbols are the same as defined for the Panhandle A equation (2.34).

The corresponding equation in SI units is as follows:

$$Q = 1.002\times 10^{-2}E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.961}T_f L_e Z}\right)^{0.51} D^{2.53} \tag{2.37}$$

where all symbols are the same as defined for the Panhandle A equation (2.35).

Example 11

Calculate the outlet pressure in a natural gas pipeline, NPS 18 with 0.250 in. wall thickness, 20 miles long, using Panhandle A and B equations. The gas flow rate is 150 MMSCFD at a flowing temperature of 70 ^{O}F. The inlet pressure is 1000 psig and the gas gravity and viscosity are 0.6 and 0.000008 lb/ft-sec, respectively. Assume base pressure = 14.7 psia and base temperature = 60 ^{O}F. Assume that the compressibility factor Z = 0.85 throughout and the pipeline efficiency is 0.95. Compare the results using the Weymouth Equation. Neglect elevation effects.

Solution

Inside diameter D = 18 – 2 x 0.250 = 17.50 in

Gas flowing temperature T_f = 70 + 460 = 530 ^{O}R

Upstream pressure P_1 = 1000 + 14.7 = 1014.7 psia

Base temperature T_b = 60 + 460 = 520 ^{O}R

Base pressure P_b = 14.7 psia

Using the Panhandle A Eq. (2.34), we get:

$$150\times10^{6} = 435.87\times0.95\left(\frac{520}{14.7}\right)^{1.0788}\left(\frac{1014.7^{2}-P_2^{2}}{0.6^{0.8539}\times530\times20\times0.85}\right)^{0.5394}17.5^{2.6182}$$

Solving, P_2 = 970.81 psia

Using the Panhandle B Eq. (2.36), we get:

$$150\times10^{6} = 737\times0.95\left(\frac{520}{14.7}\right)^{1.02}\left(\frac{1014.7^{2}-P_2^{2}}{0.6^{0.961}\times530\times20\times0.85}\right)^{0.51}17.5^{2.53}$$

Solving for the outlet pressure P_2, we get:

P_2 = 971.81 psia

Thus, both Panhandle A and B give results that are quite close.

Next using the Weymouth Eq. (2.30) we get:

$$150\times10^{6} = 433.5\times0.95\left(\frac{520}{14.7}\right)\left(\frac{1014.7^{2}-P_2^{2}}{0.6\times530\times20\times0.85}\right)^{0.5}17.5^{2.667}$$

Solving for the outlet pressure P_2, we get:

P_2 = 946.24 psia

It can be seen that the outlet pressure calculated using the Weymouth equation is the smallest value. Hence we conclude that for the same flow rate, Weymouth gives a higher pressure drop compared to Panhandle A and Panhandle B equations. Therefore, Weymouth is considered to be more conservative than the other two flow equations.

The IGT Equation

This is another flow equation for natural gas pipelines, proposed by the Institute of Gas Technology. It is frequently used in gas distribution piping systems.

In USCS units, the IGT equation is as follows:

$$Q = 136.9E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8}T_f L_e \mu^{0.2}}\right)^{0.555} D^{2.667} \quad (2.38)$$

where μ is the gas viscosity in lb/ft-s and all other symbols have been defined previously.

In SI units the IGT equation is as follows:

$$Q = 1.2822 \times 10^{-3} E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - e^s P_2^2}{G^{0.8}T_f L_e \mu^{0.2}}\right)^{0.555} D^{2.667} \quad (2.39)$$

where μ is the gas viscosity in Poise and all other symbols have been defined before.

3. Pressures and Piping System

In the previous sections we discussed how the pressure drop is related to the gas flow rate in a pipeline. We calculated flow rates, for short pipe segments, from given upstream and downstream pressures using the General Flow equation as well as Panhandle A, Panhandle B and Weymouth equations. In a long pipeline, the pressures along the pipeline may be calculated considering the pipeline sub-divided into short segments and by calculating the pressure drop in each segment. If we do not do this and consider the pipeline as one long segment, the results will be inaccurate due to the nature of the relationship between pressures and flow rates. To accurately calculate the pressures in a long gas pipeline, we have to use some sort of a computer program, because subdividing the pipeline into segments and calculating the pressures in each segment will become a laborious and time consuming process. Furthermore, if we consider heat transfer effects, the calculations will be even more complex. We will illustrate the method of calculating pressures by sub-dividing the pipeline, using a simple example. In this example we will first calculate the pressures by considering the pipeline as one segment. Next we will sub-divide the pipeline into two segments and repeat the calculations.

Example 12

A natural gas pipeline, AB is 100 mi long and is NPS16, 0.250 in. wall thickness. The elevation differences may be neglected and the pipeline assumed to be along a flat elevation profile. The gas flow rate is 100 MMSCFD. It is required to determine the pressure at the inlet A, considering a fixed delivery pressure of 1000 psig at the terminus B. The gas gravity and viscosity are 0.6 and 0.000008 lb/ft-s, respectively. The gas flowing temperature is 70 ^{O}F throughout. The base temperature and pressure are 60 ^{O}F and 14.7 psia respectively. Use CNGA method for calculating the compressibility factor. Assume transmission factor F = 20.0 and use the General Flow equation for calculating the pressures.

Solution:

The inside diameter of the pipeline is:

D = 16-2x0.250 = 15.5 in.

For the compressibility factor, we need to know the gas temperature and the average pressure. Since we do not know the upstream pressure at A, we cannot calculate an accurate average pressure. We will assume that the average pressure is 1200 psig, since the pressure at B is 1000 psig. The approximate compressibility factor will be calculated using this pressure from Eq. (1.12):

$$Z = \frac{1}{\left[1+\left(\frac{1200\times 344400\times (10)^{1.785\times 0.6}}{530^{3.825}}\right)\right]}$$

Therefore, Z = 0.8440

This value can be adjusted after we calculate the actual pressures.

Using the General Flow equation, Eq. (2.7), considering the pipeline as one 100 mile long segment, the pressure at the inlet A can be calculated as follows:

$$100\times 10^{6} = 38.77\times 20\left(\frac{520}{14.7}\right)\left(\frac{P_1^2 - 1014.7^2}{0.6\times 530\times 100\times 0.844}\right)^{0.5} 15.5^{2.5}$$

Solving for the pressure at A, we get:

P1 = 1195.14 psia or 1180.44 psig.

Based on this upstream pressure and the downstream pressure of 1000 psig at B, the average pressure becomes, from Eq. (2.26):

$$P_{avg} = \frac{2}{3}\left(1195.14 + 1014.7 - \frac{1195.14\times 1014.7}{1195.14 + 1014.7}\right)$$ = 1107.38 psia or 1092.68 psig

This compares with the average pressure of 1200 psig we initially used to calculate Z. Therefore, a more correct value of Z can be re-calculated using the average pressure calculation above. Strictly speaking we must re-calculate Z based on the new average pressure of 1092.68 psig and then re-calculate the pressure at A using the General Flow equation. The process must be repeated until successive values of Z are within a small tolerance, such as 0.01. This is left as an exercise for the reader.

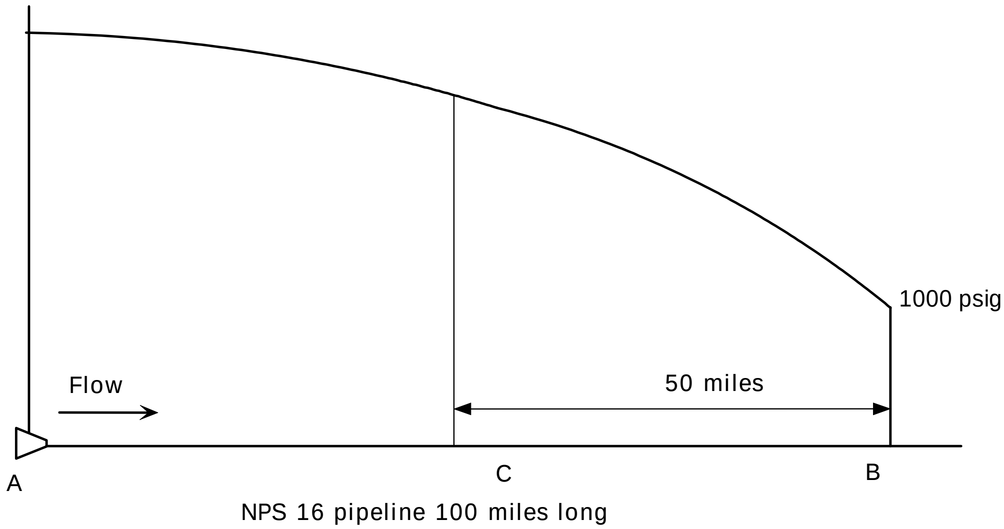

Fig. 3.1 Sub-dividing pipeline

Next we will sub-divide the 100 mi pipeline into two equal 50 mi segments. We will first calculate the upstream pressure of the second 50 mi segment based on a downstream pressure of 1000 psig at B. This will establish the pressure at the mid point of the 100 mi pipeline. Then, based on this mid-point pressure we will calculate the pressure required at A, for the first 50 mi segment. Since the pressure at A was calculated earlier as approximately 1180 psig, we will assume an average pressure of the second 50 mi segment to be approximately 1050 psig.

Calculating the compressibility factor Z:

$$Z = \frac{1}{\left[1 + \left(\frac{1050 \times 344400 \times (10)^{1.785 \times 0.6}}{530^{3.825}}\right)\right]}$$

Therefore, Z = 0.8608

Applying the General Flow equation for the second 50 mi segment:

$$100 \times 10^6 = 38.77 \times 20\left(\frac{520}{14.7}\right)\left(\frac{P_1^2 - 1014.7^2}{0.6 \times 530 \times 50 \times 0.8608}\right)^{0.5} 15.5^{2.5}$$

Solving for the pressure at the mid point C, we get:

P_1 = 1110.38 psia, or 1095.68 psig.

As before, the average gas pressure in the second segment must be calculated based on the above pressure, the pressure at B, and the recalculated value of Z. We will skip that step for now and proceed with the first 50 mi segment.

Applying the General Flow equation for the first 50 mi segment:

$$100 \times 10^6 = 38.77 \times 20\left(\frac{520}{14.7}\right)\left(\frac{P_1^2 - 1062.97^2}{0.6 \times 530 \times 50 \times 0.8608}\right)^{0.5} 15.5^{2.5}$$

Note that we have also assumed the same value for Z as before.

Solving for the pressure at A, we get:

P_1 = 1198.45 psia or 1183.75 psig.

It is seen that the pressure at A is 1180 psig when we calculate based on the pipeline as one single 100 mi segment. Compared to this, the pressure at A is 1184 psig when we subdivide the pipeline into two 50 mi segments. Subdividing the pipeline into four equal 25 mile segments will result in a more accurate solution. This shows the importance of sub-dividing the pipeline into short segments, for obtaining accurate results. As mentioned earlier, some type of hydraulic simulation program should be used to quickly and accurately calculate the pressures in a gas pipeline. One such commercial software is GASMOD, published by SYSTEK Technologies, Inc. (www.systek.us). Using this hydraulic model, the heat transfer effects may also be modeled.

The total pressure required at the inlet of a gas pipeline may be calculated easily using the method illustrated in the previous example. Similarly, given the inlet and outlet pressures, we can calculate the gas flow rate in the pipeline using the General Flow equation, Panhandle or Weymouth equations.

Next, we will now look at gas pipelines with intermediate flow injections and deliveries. As we increase the flow rate through a gas pipeline, if we keep the same delivery pressure at the pipeline terminus, the pressure at the pipeline inlet will increase. Suppose the inlet pressure of 1400 psig results in a delivery pressure of 900 psig. If the MAOP of the pipeline is 1440 psig, we cannot increase the inlet pressure above that, as flow rate increases. Therefore, we need to install intermediate compressor stations as illustrated in the preceding discussions. Suppose the flow rate increase results in the inlet pressure of 1500 psig and we do not want to install an intermediate compressor station. We could install a parallel loop for a certain length of the pipeline to reduce the total pressure drop in the pipeline such that the inlet pressure will be limited to the MAOP. The length of pipe that needs to be looped can be calculated using the theory of parallel pipes discussed in the next section. By installing a pipe loop we are effectively increasing the diameter of the pipeline for a certain segment of the line. This increase in diameter will decrease the pipeline pressure drop and hence bring the inlet pressure down below the 1500 psig required at the higher flow rate.

Looping a section of the pipeline is thus regarded as a viable option to increase pipeline throughput. In comparison with the installation of an intermediate compressor station, looping requires incremental capital investment but insignificant increase in operating cost. In contrast, a new compressor station will not only require additional capital investment, but also significant added operation and maintenance costs.

Example 13

Consider a pipeline shown in Fig 3.2 where the gas enters the pipeline at A at 100 MMSCFD, and at some point B, 20 MMSCFD is delivered to a customer. The remaining 80 MMSCFD continues to a point C where an additional volume of 50 MMSCFD is injected into the pipeline. From that point the total volume of 130 MMSCFD continues to the end of the pipeline at D, where it is delivered to an industrial plant at a pressure of 800 psig.

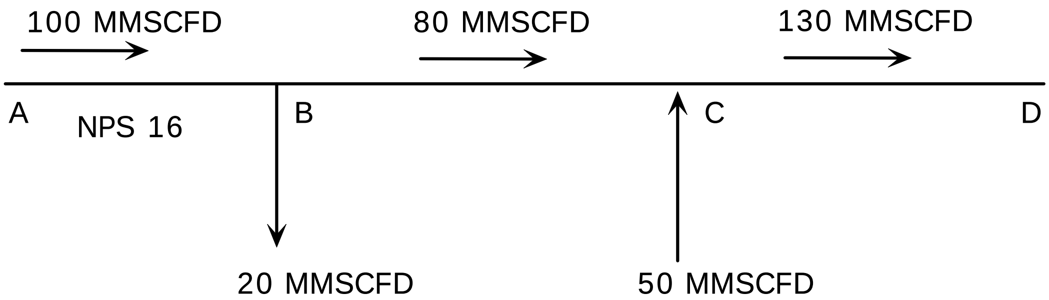

Figure 3.2 Pipeline with injection and deliveries

We would analyze this pipeline pressures required at A, B and C for this system as follows. Suppose the desired delivery pressure at the terminus D is given as 500 psig. Using this pressure as the downstream pressure for the pipe segment CD, we will calculate the upstream pressure required at C to transport 130 MMSCFD through the pipe CD. Assuming the pipe diameter for CD is known, we use the General Flow equation to calculate the pressure at C. Once we know the pressure at C, we consider the next pipe segment BC and, using the General Flow equation, calculate the upstream pressure required at B to transport 80 MMSCFD through the pipe segment BC. Similarly, we finally calculate the upstream pressure required at A to transport 100 MMSCFD through the pipe segment AB.

Due to the different flow rates in the pipes AB, BC and CD the required diameters for these pipe segments will not be the same. The largest diameter will be for segment CD that transports the greatest volume, and the smallest diameter will be for segment BC that transports the least volume.

Sometimes, we have to calculate the minimum diameters of these pipe segments, required to handle these flow rates, given both the upstream and downstream pressures at A and D. In that case we choose an initial size for AB, then based upon allowable gas velocities and starting from the end A, we calculate the downstream pressures at points B, C and D in succession, using the General Flow equation. The pipe sizes are adjusted as needed until we are able to arrive at the correct delivery pressure at D.

When pipes of different diameters are connected together end to end, they are referred to as series pipes. If the flow rate is the same throughout the system, we can simplify calculations by converting the entire system into one long piece of pipe with the *same uniform diameter,* using the equivalent length concept. We calculate the equivalent length of each pipe segment (for the same pressure drop) based on a fixed base diameter. For example a pipe of diameter D_1 and length L_1 will be converted to an equivalent length Le_1 of some base diameter D. This will be based on the same pressure drop in both pipes. Similarly the remaining pipe segments, such as the pipe diameter D_2 and length L_2 will be converted to a corresponding equivalent length Le_2 of diameter D. Continuing the process we have the entire piping system reduced to the following total equivalent length of the same diameter D as follows:

Total equivalent length = $Le_1 + Le_2 + Le_3 + \ldots$..

The base diameter D may be one of the segment diameters. For example, we may pick the base diameter to be D_1. Therefore the equivalent length becomes:

Total equivalent length = $L_1 + Le_2 + Le_3 + \ldots$..

From the General Flow equation, we see that the pressure drop versus the pipe diameter relationship is such that $\left(P_1^2 - P_2^2\right)$ is inversely proportional to the fifth power of the diameter and directly proportional to the pipe length. Therefore, we can state the following:

$$\Delta P_{sq} = \frac{CL}{D^5} \tag{3.1}$$

where:

ΔP_{sq} = $(P_1^{\,2} - P_2^{\,2})$ for pipe segment.

P1, P2 = Upstream and downstream pressures of pipe segment, psia.

C = A constant

L = pipe segment length

D = pipe segment inside diameter

Therefore for the equivalent length calculations, we can state that for the second segment:

$$Le_2 = L_2 \left(\frac{D_1}{D_2} \right)^5 \tag{3.2}$$

And for the third pipe segment the equivalent length is:

$$Le_3 = L_3 \left(\frac{D_1}{D_3} \right)^5 \tag{3.3}$$

Therefore the total equivalent length Le for all pipe segments in terms of diameter D_1 can be stated as:

$$Le = L_1 + L_2 \left(\frac{D_1}{D_2} \right)^5 + L_3 \left(\frac{D_1}{D_3} \right)^5 + \ldots. \tag{3.4}$$

We are thus able to reduce the series pipe system to one of fixed diameter and equivalent length. The analysis then would be easy since all pipe sizes will be the same. However, if the flow rates are different in each section, there is really no benefit in calculating the equivalent length, since we have to consider each segment separately and apply the General Flow equation for each flow rate. Therefore the equivalent length approach is useful only if the flow rate is the same throughout the series piping system.

Pipes may also be connected in parallel as shown in Fig 3.3. This is also called a looped system. We will next discuss how the pressures and flow rates are calculated in parallel piping systems.

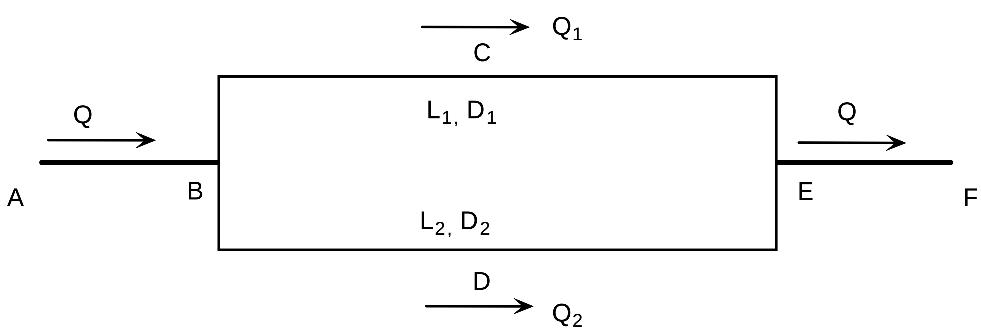

Fig. 3.3 Parallel pipes

In Fig 3.3 we have a pipe segment AB connected to two other pipes (BCE and BDE) in parallel, forming a loop. The two pipes rejoin at E to form a single pipe segment EF. We can replace the two pipe segments BCE and BDE by one pipe segment of some length L_e and diameter D_e. This will be based on the same pressure drop through the equivalent piece of pipe as the individual pipes BCE and BDE. The flow rate Q through AB is split into two flows Q_1 and Q_2 as shown in the figure, such that $Q_1 + Q_2 = Q$.

Since B and E are the common junctions for each of the parallel pipes, there is a common pressure drop ΔP for each pipe BCE or BDE. Therefore the flow rate Q1 through pipe BCE results in pressure drop ΔP just as the flow rate Q_2 through pipe BDE results in the same pressure drop ΔP. The equivalent pipe of length Le and diameter De must also have the same drop ΔP at the total flow Q, in order to completely replace the two pipe loops. Using this principle, and noting the pressure versus diameter relationship from the General Flow equation, we can calculate the equivalent diameter D_e based on setting Le equal to the length of one of the loops BCE or BDE.

Another approach to solving the flows and pressures in a looped system is to calculate the flows Q1 and Q2 based on the fact that the flows should total Q and the fact that there is a common pressure drop ΔP across the two parallel segments.

Using the General Flow equation, for common ΔP, we can state that:

$$\frac{L_1 Q_1^2}{D_1^5} = \frac{L_2 Q_2^2}{D_2^5} \tag{3.5}$$

where L_1 and L_2 are the two pipe segment lengths for BCE and BDE and D_1 and D_2 are the corresponding inside diameters.

Simplifying the preceding equation, we get:

$$\frac{Q_1}{Q_2} = \left(\frac{L_2}{L_1}\right)^{0.5} \left(\frac{D_1}{D_2}\right)^{2.5} \tag{3.6}$$

Also

$$Q = Q_1 + Q_2 \tag{3.7}$$

Using the two preceding equations, we can solve for the two flows Q_1 and Q_2. Once we know these flow rates, the pressure drop in each of the pipe loops BCE or BDE can be calculated.

Looping a gas pipeline effectively increases pipe diameter, and hence results in increased throughput capability. If a 50 mile section of NPS 16 pipeline is looped using an identical pipe size, the effective or the equivalent diameter D_e and length Le are related as follows from the preceding Eq. (3.5):

$$\frac{L_e Q^2}{D_e^5} = \frac{L_1 Q_1^2}{D_1^5} = \frac{L_2 Q_2^2}{D_2^5}$$

By setting the length L_1, L_2 and Le to equal 50 miles, the equivalent diameter D_e may be calculated, after some simplification and using Eq.(3.6), and (3.7) as follows:

$$D_e^5 = D_2^5 \left[1 + \left(\frac{D_1}{D_2} \right)^{2.5} \right]^2$$

Since the loop diameters are the same, D1 = D2 = 15.5 in, assume a wall thickness of 0.25 in.

Solving for the equivalent diameter, we get:

$$D_e^5 = 15.5^5 \left[1 + \left(\frac{15.5}{15.5} \right)^{2.5} \right]^2$$

Or D_e = 20.45 in.

Compared to the unlooped pipe, the looped pipeline will have an increased capacity of approximately:

$Q_L/Q = (20.45/15.5)^{2.5} = 2.0$

We have thus demonstrated that by looping the pipeline, the throughput can be increased to twice the original value. Suppose instead of looping the NPS 16 pipe with an identical diameter pipe, we looped it with NPS 20 pipe with a wall thickness of 0.375 inch, the equivalent diameter becomes:

D_e = 23.13 inch

And the increased capacity ratio becomes:

$Q_L/Q = (23.13/15.5)^{2.5} = 2.72$

Thus by looping the NPS 16 pipe with a NPS 20 pipe, the capacity can be increased to 2.72 times the original throughput. This method of increasing pipeline capacity by looping involves initial capital investment but no increased HP, such as that when we install a compressor. Thus we can compare the cost of looping a pipeline with installing additional compressor stations.

4. Compressor Stations and HP

Compressor stations provide the pressure required to transport the gas in a pipeline from one location to another. Suppose that a 20 mile long pipeline requires 1000 psig pressure at the pipe inlet A to deliver the gas at 100 MMSCFD flow rate to the terminus B at 900 psig. If the gas at A is at 800 psig pressure, it needs to be compressed to 1000 psig using a compressor located at A. The compressor is said to provide a compression ratio of $\frac{1000+14.7}{800+14.7}$ = 1.25. Note that pressures must be converted to the absolute pressures and hence the reason for adding 14.7, the base pressure, to the given pressures. We say that the compressor suction pressure is 814.7 psia and the discharge pressure is 1014.7 psia. Suppose the gas inlet temperature on the compressor suction side is 80 ^{O}F. Because of the compression process, the gas temperature at the compressor discharge will increase, just like the discharge pressure. If the compression process is adiabatic or isentropic, pressure versus volume will obey the adiabatic compression equation as follows:

$$PV^{\gamma} = \text{constant} \tag{4.1}$$

where γ is the ratio of the specific heats (Cp/Cv) of the gas. This ratio is approximately 1.29 for natural gas. Using the above equation in conjunction with the ideal gas equation, we can write a relationship between the pressure P and the temperature T for the compression process as follows:

$$P^{\frac{1-\gamma}{\gamma}} T = \text{Constant} \tag{4.2}$$

If the suction conditions are represented by the subscript 1 and the discharge conditions by the subscript 2, the discharge temperature of the compressed gas can be calculated as follows:

$$\left(\frac{T_2}{T_1}\right) = \left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} \tag{4.3}$$

where all temperatures are in ^{O}R and the pressures are in psia.

Taking into account the compressibility of the gas, the temperature ratio above becomes:

$$\left(\frac{T_2}{T_1}\right) = \left(\frac{Z_1}{Z_2}\right)\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} \tag{4.4}$$

where Z_1 and Z_2 are gas compressibility factor at suction and discharge conditions, respectively.

When the compression process is polytropic, we use the polytropic coefficient n instead of g and the temperature ratio then becomes:

$$\left(\frac{T_2}{T_1}\right) = \left(\frac{Z_1}{Z_2}\right)\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} \tag{4.5}$$

Horsepower required

The compressors compress the natural gas and raise its pressure (and its temperature) to the level required to ensure that the gas will be transported from point A to point B, such that the required outlet pressure can be maintained. The higher the outlet pressure at B, the higher will be the pressure required at A. This will cause the compressors to work harder. The energy input to the gas by the compressors will depend upon the compression ratio and gas flow rate, among other factors. From the energy input to the gas, we can calculate the horsepower (HP) needed.

The following equation may be used to calculate the compressor HP.

$$HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \tag{4.6}$$

where:

HP = compression horsepower

γ = Cp/Cv the ratio of specific heats of gas

Q = gas flow rate, MMSCFD

T_1 = suction temperature of gas, ^{O}R

P_1 =suction pressure of gas, psia

P_2 = discharge pressure of gas, psia

Z_1 = compressibility of gas at suction conditions, dimensionless

Z_2 = compressibility of gas at discharge conditions, dimensionless

η_a = compressor adiabatic (isentropic) efficiency, decimal value

In SI units, the compressor Power required is as follows:

$$Power = 4.0639\left(\frac{\gamma}{\gamma - 1}\right)QT_1\left(\frac{Z_1 + Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \tag{4.7}$$

where:

Power = compression Power, kW

Q = gas flow rate, Mm^3/day

T_1 = suction temperature of gas, K

P_1 = suction pressure of gas, kPa

P_2 = discharge pressure of gas, kPa

Other symbols are the same as defined previously.

The adiabatic efficiency, also called the isentropic efficiency, is approximately 0.75 to 0.85. Taking into account a mechanical efficiency η_m of the compressor driver, the Brake Horsepower (BHP) required may be calculated as follows:

$$BHP = \frac{HP}{\eta_m} \tag{4.8}$$

The mechanical efficiency η_m of the driver generally varies from 0.95 to 0.98. By multiplying the two efficiencies, we get the overall efficiency η_o as follows:

$$\eta_o = \eta_a \times \eta_m \tag{4.9}$$

The adiabatic efficiency can be calculated, knowing the actual discharge temperature of the gas, suction and discharge pressures and the compressibility factors, using the following equation:

$$\eta_a = \left(\frac{T_1}{T_2 - T_1}\right)\left[\left(\frac{Z_1}{Z_2}\right)\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \tag{4.10}$$

Suppose the inlet temperature of the gas at the compressor suction is 70 ^{O}F and the suction and discharge pressures are 900 psia and 1200 psia, respectively. If the compressor discharge temperature is 250 ^{O}F, the compressor adiabatic efficiency may be calculated using the preceding equation. Assuming γ = 1.4 and the compressibility factors as Z_1 = 1.0 and Z_2 = 0.85, we get:

$$\eta_a = \left(\frac{70+460}{250-70}\right)\left[\left(\frac{1.0}{0.85}\right)\left(\frac{1200}{900}\right)^{\frac{1.4-1}{1.4}} - 1\right] = 0.8164$$

Example 14

Calculate the compression HP required to adiabatically compress natural gas at 100 MMCFD, starting at an inlet temperature of 80 ^{O}F and 800 psia pressure. The compression ratio is 1.6 and the gas compressibility factor at suction and discharge condition are Z_1 = 1.0 and Z_2 = 0.85 and the ratio of specific heats of the gas is γ = 1.4. Consider the compressor adiabatic efficiency η_a = 0.8. What is the BHP is required, for a mechanical efficiency of 0.98.

Solution

From Eq. (4.6), the horsepower can be calculated as:

$$HP = 0.0857 \times 100\left(\frac{1.40}{0.40}\right)(80+460)\left(\frac{1+0.85}{2}\right)\left(\frac{1}{0.8}\right)\left[(1.6)^{\frac{0.40}{1.40}} - 1\right] = 2692$$

The driver BHP required is calculated from Eq. (4.8) as:

$$\text{BHP} = \frac{2692}{0.98} = 2747$$

So far we examined a pipeline with one compressor station at the beginning of the pipeline. Consider a 120 mile long pipeline, NPS 18, 0.375 in. wall thickness from Beaumont to Denver, transporting 300 MMSCFD Suppose calculations showed that the pressure required at Beaumont is 1800 psig based on application of the General Flow equation, to provide a delivery pressure of 800 psig at the Denver terminus. This is illustrated in Fig 4.1 below.

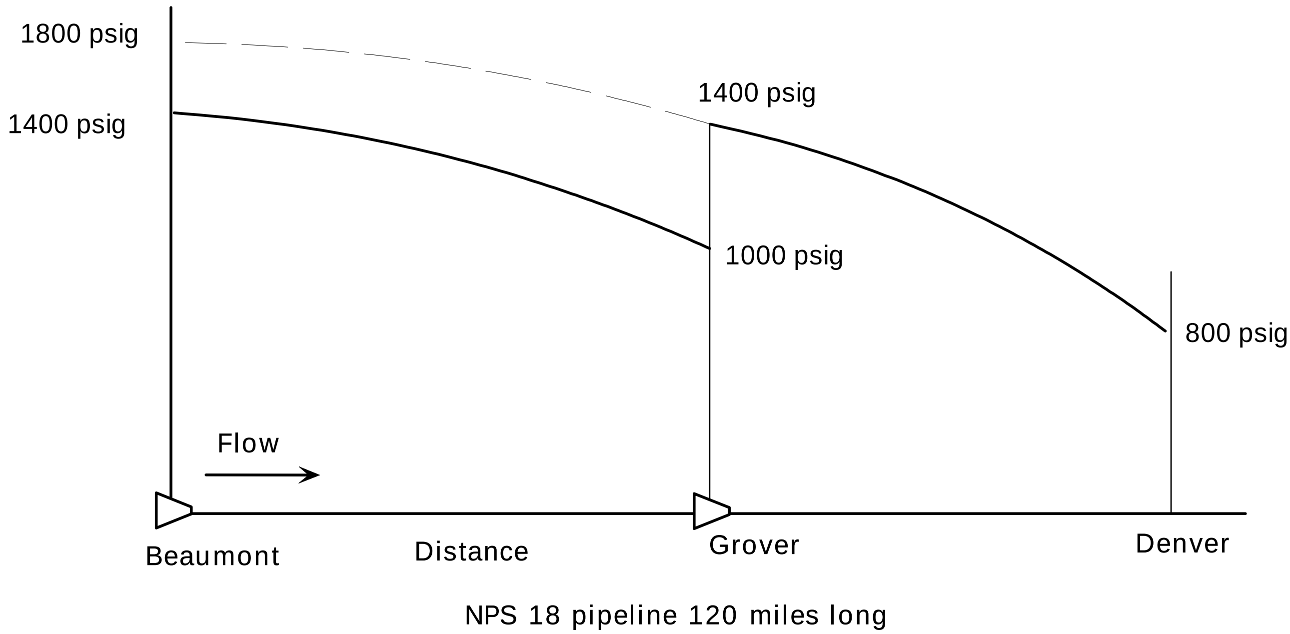

Figure 4.1 Compressor stations required

If the maximum allowable operating pressure (MAOP) of the pipeline is limited to 1400 psig, we cannot just install one compressor station at the beginning to provide the necessary pressure, since the 1800 psig is beyond the pipe MAOP. Therefore, by installing an additional intermediate compressor station at Grover, as shown in the figure, we can keep each compressor station discharge pressure at the MAOP limit. The location of the Grover compressor station will depend upon the MAOP, the allowable compression ratio and the suction pressure. One approach is to calculate the distance x between Grover and Denver, such that starting at 1400 psig at Grover, the gas outlet pressure at Denver is exactly 800 psig. We would apply the General Flow equation to the x mile length of pipe with upstream pressure set at P_1 = (1400 + 14.7) psia and downstream pressure P_2 = (800 +14.7) psia.

Having calculated the value of x and hence the location of Grover, we must calculate the suction pressure at Grover, by considering the pipe segment between Beaumont and Grover. If the suction pressure at Grover is too low, the compression ratio for the Grover compressor will be too high. Generally the compression ratio is limited to 1.2 to 1.8 for centrifugal compressors. If the suction pressure at Grover is too low, we will have to consider installing two (2) intermediate compressors instead of one at Grover. These two compressor stations will be located such that the suction pressures do not fall too low and the compression ratio is within limits.

5. Strength of Pipe

In earlier sections of this course, we calculated the pressures and flow rates in a natural gas pipeline. Using the flow equations, we calculated the minimum pressure required to transport gas at a certain flow rate and temperature from one point to another. The pipe used for transportation of gas should be able to withstand the necessary internal pressure. The internal pressure in a pipe is limited to what the pipe material and wall thickness can withstand at a certain temperature. As the pipe pressure is increased, the stress in the pipe material increases. Ultimately, at some internal pressure the pipe will rupture. Therefore for each pipe size and wall thickness, depending upon the pipe material, there is a safe internal pressure beyond which it is not advisable to operate the pipeline. This is known as the maximum allowable operating pressure (MAOP), sometimes shortened to maximum operating pressure (MOP). There are two stresses developed in a pipe wall due to internal pressure. The larger of the two is called the hoop stress and acts in the circumferential direction. The second is the axial or longitudinal stress that acts along the axial direction. The axial stress is one-half the magnitude of the hoop stress. This is illustrated in the Fig. 5.1.

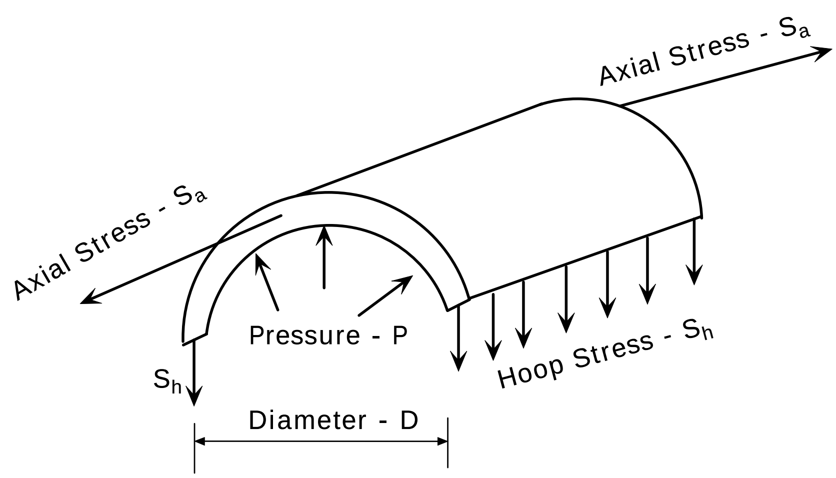

Fig 5.1 Pipe stresses due to internal pressure

The allowable internal pressure can be easily calculated using the Barlow’s equation as follows:

$$S_h = \frac{PD}{2t} \tag{5.1}$$

where:

S_h = allowable hoop stress in pipe, psig

P = allowable internal pressure, psig

D = pipe outside diameter, in.

t = pipe wall thickness, in.

Even though the Barlow's equation is for calculating the hoop stress in the pipe for a given internal pressure, we can easily re-arrange the equation to solve for the pressure P.

$$P = \frac{2tS_h}{D} \tag{5.2}$$

Thus for an NPS 20 pipe, 0.500 in. wall thickness, if the allowable hoop stress is limited to 30,000 psig, the allowable internal pressure is:

P = $\frac{2 \times 0.5 \times 30{,}000}{20} = 1500$ psig

The longitudinal stress, Sa, can be calculated from a similar equation as follows:

$$S_a = \frac{PD}{4t} \tag{5.3}$$

It must be noted that unlike the General Flow equation or other flow equations, the diameter used here is the outside diameter, not the inside diameter. In practice, to calculate the internal design pressure for a gas pipeline, we modify the Barlow's equation slightly by introducing some factors that depend upon the pipeline manufacturing method, operating temperature and the class location of the pipeline. The modified equation is as follows:

$$P = \frac{2tSEFT}{D} \tag{5.4}$$

where:

P = internal design pressure, psig

D = outside diameter of pipe, in.

t = pipe wall thickness, in.

S = Specified Minimum Yield Strength (SMYS) of pipe material, psig

E = seam joint factor, 1.0 for seamless and Submerged Arc Welded (SAW) pipes.

F = design factor, usually 0.72 for cross country gas pipelines but may be as low as 0.4, depending upon class location and type of construction.

T = temperature deration factor = 1.00 for temperatures below 250 ^{O}F

For further details on the above internal design pressure equation, refer to the DOT 49 CFR part 192 or ASME B31.8 standard. The design factor F depends upon the population density and dwellings in the vicinity of the pipeline. Class locations 1 through 4 are defined by DOT based on the population density. Accordingly the values for F are as shown in Table 2.

Table 2 - Design Factor

Class Location	Design Factor, F
1	0.72
2	0.60
3	0.50
4	0.40

The following definitions for Class locations are taken from the DOT 49 CFR Part 192 code. The class location unit (CLU) is defined as an area that extends 220 yards on either side of the centerline of a one mile section of pipe. Offshore gas pipelines are known as Class 1 locations. For onshore pipelines, any class location unit with 10 or fewer buildings intended for human occupancy is termed Class 1. Class 2 locations are defined as those areas with more than 10 but less than 46 buildings intended for human occupancy. Class 3 locations are defined for areas that have 46 or more buildings intended for human occupancy or an area where the pipeline is within 100 yards of a building or a playground, recreation area, outdoor theatre or other place of public assembly that is occupied by 20 or more people on at least five days a week for ten weeks in any 12 month period. The days and weeks needed not be consecutive. Class 4 locations are defined for areas with multi-story buildings, such as four or more stories above ground.

The temperature deration factor T, used in Eq. (5.4) is equal to 1.00 as long as the temperature of the gas in the pipe does not exceed 250 ^{O}F. At higher temperatures a value of T less than 1.00 is used as indicated in Table 3.

Table 3 - Temperature Deration Factor

Temperature		Derating Factor, T
^{O}F	^{O}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

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Strictly speaking, Barlow's equation is correct only for thin walled cylindrical pipes. For thick walled pipes a different formula must be used. In practice, however, most gas pipelines fall within the category of thin walled pipes.

Example 15

A gas pipeline, NPS 20 is operated at an internal pressure of 1200 psig. The yield strength of the pipe material is 52,000 psig. Calculate the minimum wall thickness required for operation, below 200 ^{O}F.

Solution

From Eq. (5.4), assuming a design factor of 0.72 and temperature derating factor of 1.00, the pipe wall thickness is calculated as:

$$t = \frac{1200 \times 20}{2 \times 52000 \times 0.72 \times 1.0} = 0.3205 \text{ in.}$$

Steel pipe material used in gas pipelines are manufactured in accordance with API specifications 5L and 5LX. Several grades designated as X-42, X-52, etc are used. These designations refer to the SMYS of the pipe material. For example, X-42 steel has an SMYS of 42,000 psig, whereas X-52 has an SMYS of

52,000 psig. Other grades commonly used are X-60, X-65 and X-70. In some cases for low pressure applications, API 5L grade B pipe with SMYS of 35,000 psig is used.

Example 16

A natural gas pipeline, NPS 16, 0.250 in. wall thickness, is constructed of API 5L X 70 steel pipe. Calculate the MOP of this pipeline for the various DOT class locations. Assume temperature deration factor = 1.00.

Solution

Using Eq. (5.4) the MOP is given by:

$$P = \frac{2 \times 0.250 \times 70000 \times 1.0 \times 0.72 \times 1.0}{16} = \text{1575 psig for class 1}$$

Repeating calculations, by proportions, for the various class locations, we get:

Class 2, MOP = $1575 \times \frac{0.6}{0.72}$ = 1312.5 psig

Class 3, MOP = $1575 \times \frac{0.5}{0.72}$ = 1093.75 psig

Class 4, MOP = $1575 \times \frac{0.4}{0.72}$ = 875 psig

In order to ensure that a pipeline may be operated safely at a certain MOP, before putting it into service, it must be hydrostatically tested to a higher pressure and held at that pressure for a specified period of time, without any leaks or rupture of pipe. The magnitude of the hydrotest pressure is usually 125 percent of the operating pressure. Therefore if the MOP is 1000 psig, the pipeline will be hydrotested to a minimum pressure of 1250 psig. Considering a design factor of 0.72, the operation of a pipeline at the MOP will result in the hoop stress reaching 72% of the SMYS. Since the hydrotest pressure is 125 percent of the MOP, the corresponding hoop stress in the pipe during the testing will be 1.25 times 72% or 90% of SMYS. Usually, the hydrotest envelope is such that the hoop stress is between 90% and 95% of the SMYS. Thus, if the MOP is 1000 psig, the hydrotest envelope will be between 1250 psig and 1319 psig. For buried pipelines, the hydrotest pressure is held constant for a period of 8 hours and it is thoroughly checked for leaks. For above ground pipelines, the hydrotest period is 4 hours.

Frequently, in gas pipeline hydraulics, we are interested in knowing the quantity of pipe required for a project. There is a simple formula for calculating the weight of pipe per unit length of pipe. For a given pipe of outside diameter D and wall thickness t, the weight per foot of pipe is given by:

$$w = 10.68\ t\ (D-t) \qquad (5.5)$$

where D and t are in inches and w is in lb/ft.

For example, a 20 mile pipeline, and NPS 20 with 0.500 in wall thickness, has a total pipe weight of:

W = 20 x 5280 x 10.68 x 0.500 x (20-0.5) = 10,996,128 lb or 5,498 tons

Summary

In this course we addressed the hydraulics of compressible fluids such as natural gases. First we introduced the relevant properties of gas that affect pipeline hydraulics. Next, the methods of calculating pressures and flow rates in a natural gas pipeline was analyzed, with reference to several popular equation of gas flow. We compared the various flow equations and found some were more conservative than others. Using the pressure calculated, the compressor HP was estimated. The need for installing additional intermediate compressor stations, based on allowable pipe pressures, was explained. Methods of increasing pipeline throughput were discussed. The strength requirement of pipes to withstand the internal pressure was reviewed using the Barlow's equation.

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