Chapter 10: Compression and Cooling
Introduction

A gas compressor is a mechanical device that increases the pressure of a gas by reducing its volume. Compressors are similar to pumps: both increase the pressure on a fluid and both can transport the fluid through a pipe. Compressors are used for gases while pumps are used for liquids. As gases are compressible, the compressor also reduces the volume of a gas.

Portable compressors were first utilized in the late 1880s in the mining industry to drill in-mine pneumatic percussion boreholes. Deep petroleum and natural wells were drilled utilizing portable air compressors in the 1920s. With the advent of natural gas and its use as a fuel, the necessity arose of transporting natural gas from the gas well to the ultimate consumer. A compressor was unnecessary as long as the pressure at the gas well could force the gas through the pipeline to its destination. Compressors became essential because gas transmission pipelines extended great distances from the gas field.
Uses of compressor

Compressors used in the oil and gas industry are divided into six groups according to their intended service. These are:

- Flash gas compressors
- Gas lift compressors
- Reinjection compressors
- Booster compressors
- Vapor-recovery compressors
- Casinghead compressors

Flash gas compressors

Flash gas compressors are used in oil handling facilities to compress gas that is “flashed” from a hydrocarbon liquid when the liquid flows from a higher pressure to a lower pressure separator. Flash gas compressors typically handle low flow rates and produce high compression ratios.
Gas lift compressors
Gas lift compressors are frequently used in oil handling facilities where compression of formation gases and gas lift gas is required. Gas lift compressor duty is frequently of low to medium throughput with high compression ratios. Many gas lift compressors are installed on offshore facilities.

Reinjection compressors
The reinjection of natural gas is employed to increase or to maintain oil production. Reinjection compressors can be required to deliver gas at discharge pressures in excess of 10,000 psi. Reinjection compressors also are used for underground storage of natural gas. Compressors, applied to these services, have large compression ratios, high power requirements, and low volume flow rates.

Casinghead compressors
Casinghead compressors are usually used with electric submersible pumps and rod pumps where formation gas is required to be separated downhole and then transported through the annulus. Often the compressor discharge is routed to either a booster or flash gas compressor or to a low-pressure gathering system. Like vapor recovery compressors, casinghead compressors operate with low suction pressures, high compression ratios, and low gas throughput rates.
**Booster compressors**
Gas transmission through pipelines results in pressure drop because of friction losses. Booster compressors are used to restore the pressure drop from these losses. Selection of these compressors involves evaluating the economic trade-off of distance between pipeline boosting stations and life-cycle cost of each compressor station. Booster compressors also are used in fields that are experiencing pressure decline. Most centrifugal pipeline booster compressors are gas turbine driven, although the use of variable-speed motor drives is becoming more prevalent. Low-speed integral gas engine reciprocating compressors also are used for gas transmission applications. Booster compressors typically are designed for high throughput rates and low compression ratio. Many booster applications can be configured in a single-stage centrifugal compressor.

**Vapor recovery compressors**
Vapor recovery compressors are used to gather gas from tanks and other low-pressure equipment in the facility. Often the gas from a vapor recovery compressor is routed to a flash gas, gas lift, or booster compressor for further compression. Low suction pressures, high compression ratios, and low gas throughput rates characterize these compressors.
Classification and types of compressor

Compressors are classified into two major categories:

- Positive displacement compressors
- Dynamic or kinetic compressors

Diagram:

- Compressor Types
  - Positive Displacement
    - Reciprocating
      - Single Acting
      - Double Acting
    - Diaphragm
  - Dynamic
    - Centrifugal
    - Axial
- Rotary
  - Lobe
  - Screw
  - Liquid Ring
  - Scroll
  - Vane
Positive displacement compressors

Positive-displacement gas compressors work by forcing gas into a chamber whose volume is decreased to compress the gas. Piston-type compressors use this principle by pumping gas into a gas chamber through the use of the constant motion of pistons. Positive displacement compressors are further divided into:

- Reciprocating
- Rotary types

Reciprocating compressors are most commonly used in the natural gas industry. They are built for practically all pressures and volumetric capacities.
Dynamic or kinetic compressors

Dynamic compressors are continuous-flow machines in which a rapidly rotating element accelerates the gas as it passes through the element, converting the velocity head into pressure, partially in the rotating element and partially in stationary diffusers or blades. Dynamic compressors are further divided into:

- Centrifugal
- Axial-flow
- Mixed-flow types
Centrifugal compressors have few moving parts because only the impeller and shaft rotate. Thus, its efficiency is high and lubrication oil consumption and maintenance costs are low. Cooling water is normally unnecessary because of lower compression ratio and lower friction loss. Compression rates of centrifugal compressors are lower because of the absence of positive displacement. Centrifugal compressors compress gas using centrifugal force. In this type of compressor, work is done on the gas by an impeller. Gas is then discharged at a high velocity into a diffuser where the velocity is reduced and its kinetic energy is converted to static pressure. Unlike reciprocating compressors, all this is done without confinement and physical squeezing. Centrifugal compressors with relatively unrestricted passages and continuous flow are inherently high-capacity, low-pressure ratio machines that adapt easily to series arrangements within a station. In this way, each compressor is required to develop only part of the station compression ratio. Typically, the volume is more than 100,000 cfm and discharge pressure is up to 100 psig.
Compressor Stations

Compressor stations are facilities located along a natural gas pipeline which compress the gas to a specified pressure, thereby allowing it to continue traveling along the pipeline to the intended recipient. When natural gas does not have sufficient potential energy to flow, a compressor station is needed.

Compressor stations enable the natural gas itself to travel through the pipelines which is crucial to the natural gas transport system. They also allow the gas to be rerouted into storage areas during periods of low demand. In addition, compressor stations are often accompanied by PIG launchers and PIG receivers which are vital for the maintenance and efficiency of the pipeline. They even include many safety features allowing the pipeline and station to function safely.

The total number of compressor station facilities required to move product varies depending on the region and conditions. Generally compressor stations are located about every 40-70 miles along the pipeline.

Depending on the particular compressor station, its size, sophistication, and other factors, it may or may not be staffed with live, on-site personnel. Many modern compressor stations can be completely monitored and operated remotely.
Compressor Station Facilities

Compressor Unit – The compressor unit is the piece of equipment which actually compresses the gas. Some compressor stations may have multiple compressor units depending on the needs of the pipeline. The compressor unit is a large engine which typically works in one of three ways:

▪ Turbines with Centrifugal Compressors – This type of compressor is powered by a turbine to turn a centrifugal compressor and is powered by natural gas from the pipeline itself.
▪ Electric Motors with Centrifugal Compressors – This type of compressor also utilizes centrifugal compressors to compress the gas; however, instead of being powered by a natural gas fueled turbine, they instead rely on high voltage electric motors.
▪ Reciprocating Engine with Reciprocating Compressor – This type of compressor uses large piston engines to crank reciprocating pistons located within cylindrical cases on the side of the unit. These reciprocating pistons compress the gas. These engines are also fueled by natural gas.

Filters and Scrubbers – Another component of compressor stations are filters and scrubbers which remove water, hydrocarbons, and other impurities from the natural gas.
Gas Cooling Systems – When the natural gas is compressed its temperature rises. This is usually offset by having the gas travel through cooling systems which return it to temperatures that will not damage the pipeline.

Mufflers – Mufflers are typically present to help reduce the noise level at compressor stations. These are especially important if the compressor station is located near residential or other inhabited areas.

PIG launchers and PIG receivers which are vital for the maintenance and efficiency of the pipeline.

Safety features allowing the pipeline and station to function safely.

Operating Pressure of the Pipeline

There is a wide variation in the pressure within a given section of pipeline compared to other pipelines in other areas. The typical pressure may range anywhere from 200 psi (pounds per square inch) to 1,500 psi. This wide variation is also due to the type of area in which the pipeline is operating, its elevation, and the diameter of the pipeline. Because of the change in the environment, compressor stations may compress natural gas at different levels. Supply and demand can also be a factor at times in the level of compression required for the flow of the natural gas.
Design considerations

Compressor stations can be designed so that they can be started, stopped and controlled by operators at a remote location, i.e., the next station or the main office. They can also be automatic where the compressor units can be started and stopped by pressure-sensitive devices.

One such design would be three stations as a unit. The center station would be a manned engine type with unmanned gas turbine stations on either side of it to be controlled and maintained by the center station.

There are at least two environmental problems with compressor stations – noise and exhaust emissions. Noise can be controlled with mufflers. Exhaust emissions can be chemically controlled with wet scrubbers, but they are expensive. These problems should be solved at the time the compressors are purchased. Remote and unmanned stations should have an automatic fire control system with alarm to the nearest manned station.
Types of Compressor Stations

Five types of compressor stations are generally utilized in the natural gas production industry:

- **Field gas-gathering** stations to gather gas from wells in which pressure is insufficient to produce at a desired rate of flow into a transmission or distribution system. These stations generally handle suction pressures from below atmospheric pressure to 750 psig and volumes from a few thousand to many million cubic feet per day.

- **Relay or main line** stations to boost pressure in transmission lines. They compress generally large volumes of gas at a pressure range between 200 and 1,300 psig.

- **Repressuring or recycling** stations to provide gas pressures as high as 6,000 psig for processing or secondary oil recovery projects.

- **Storage field** stations to compress trunk line gas for injection into storage wells at pressures up to 4,000 psig.

- **Distribution plant** stations to pump gas from holder supply to medium- or high-pressure distribution lines at about 20 to 100 psig, or pump into bottle storage up to 2,500 psig.
Compression theory

Both positive displacement and dynamic compressors are governed by a few basic principles derived from the laws of thermodynamics. This section defines terminology and discusses the operating principles essential for understanding compressor design, operation, and maintenance.

Compressor selection

Proper selection of the compressor type and number of stages can be accomplished only after considering a number of factors. (For the purposes of this chapter, discussion is limited to centrifugal vs. reciprocating compressors.) Basic information needed for the proper selection includes:

- Volume and mass flow of gas to be compressed
- Suction pressure, Discharge pressure, Suction temperature
- Gas specific gravity, Available types of drivers

Compression ratio

Compression ratio, $R_c$, is simply the absolute discharge pressure divided by the absolute suction pressure. Temperature ratio increases with pressure ratio. Temperature limits related to the mechanical design of compressors often will dictate the maximum pressure ratio that can be achieved in a stage of compression. In a design, if required overall compression ratio is greater than 6, then compression stages are needed.
Isentropic (adiabatic) compression

An adiabatic process is one in which no heat is added or removed from the system. Adiabatic compression is expressed by

$$P_1V_1^k = P_2V_2^k$$

where $k = \frac{C_p}{C_v} = ratio \ of \ specific \ heats, \ dimensionless$.

Although compressors are designed to remove as much heat as possible, some heat gain is inevitable. Nevertheless, the adiabatic compression cycle is rather closely approached by most positive displacement compressors and is generally the base to which they are referred.

When inlet temperature is known, the discharge temperature can be determined from the relationship

$$\frac{T_2}{T_1} = \left(\frac{z_1}{z_2}\right) \left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}}$$

Adiabatic efficiency is defined as the ratio of work output for an ideal isentropic compression process to the work input to develop the required head. For a given compressor operating point, the actual or predicted isentropic efficiency is

$$\eta_{is} = T_s\left[\left(\frac{P_d}{P_s}\right)^{(k-1)/k} - 1\right]/(T_d - T_s)$$

$S$=suction, $d$=discharge
**Polytropic compression**

A polytropic process is one in which changes in gas characteristics during compression are considered. *Dynamic compressors* generally follow the polytropic cycle as defined by the formula

\[ P_1 V_1^n = P_2 V_2^n \]

where \( n = \text{polytropic exponent} \).

The polytropic exponent \( n \) is experimentally determined for a given type of machine and may be lower or higher than the adiabatic exponent \( k \). Because the value of \( n \) changes during the compression process, an average value is used.

When inlet and discharge pressures and temperatures are known, the polytropic exponent can be determined from the relationship

\[ \frac{T_2}{T_1} = \left( \frac{z_1}{z_2} \right) \left( \frac{P_2}{P_1} \right)^\frac{n-1}{n} \]

The **efficiency** of the polytropic compression process is given by

\[ \eta_p = \frac{[(k - 1)/k] \left( \ln \frac{P_d}{P_s} \right)}{\ln \left( \frac{T_d}{T_s} \right)} \]
Power requirement
The total power requirement of a compressor for a given duty is the sum of the gas power and the friction power. The gas power is directly proportional to head and mass flow and inversely proportional to efficiency. Mechanical losses in the bearings and, to a lesser extent, in the seals are the primary source of friction power. For centrifugal compressors, the gas power can be calculated as

\[ HP = \frac{mH}{\eta} \]

where
- \( HP \) = gas power, horsepower
- \( m \) = mass flow rate, \( \text{lbm/min} \)
- \( H \) = compressor head, \( \text{ft-lbf/lbm} \)

By considering mechanical efficiency, \( \eta_m \) of compressor drivers, the brake horsepower, BHP is given by

\[ BHP = \frac{HP}{\eta_m} \]

Example
Natural gas is compressed by a reciprocating compressor from 60 F suction temperature and a compression ratio of 2. Calculate the discharge temperature assuming \( z \) is constant and \( k=1.3 \)

\[ \frac{T_2}{(60 + 460)} = (2)^{0.3} = 1.173 \quad T_2 = 610 \text{ R} = 150 \text{ F} \]
Stage compression

Number of stages of compression
Using the specified overall pressure ratio and suction temperature (and an assumed efficiency), the discharge temperature for compression of gas with a known k value in a single stage can be estimated by

\[
\ln \left( \frac{T_2}{T_1} \right) = \frac{\left[ ((k - 1)/k)( \ln \left( \frac{P_2}{P_1} \right)) \right]}{\eta_p}
\]

\( \eta_p \) = assumed polytropic efficiency,
\( \approx 0.72 \) to 0.85 for centrifugal compressors,
\( \approx 1.00 \) for reciprocating compressors.

If the single-stage discharge temperature is too high (typical limit is 300 to 350 °F), it is necessary to configure the compression equipment in more than one stage. Calculating the compression ratio per stage does the evaluation of a multistage design.

Pressure Ratio
It is the ratio of the discharge pressure to the inlet pressure; in practice, pressure ratio seldom exceeds 4

\[
r = \left( \frac{p_d}{p_s} \right)^{1/N_s}
\]
Intercooling
Where large pressure ratios are needed, splitting the compression duty into one or more stages with intercooling between stages can be the most energy efficient arrangement. The energy savings must be compared with the capital and maintenance investment necessary to provide the cooling. In addition to the thermodynamic benefit, intercooled compression systems result in lower discharge temperatures, which reduce the need for special compressor materials.
Calculation of the heat removed by intercoolers and aftercoolers can be accomplished using constant pressure specific heat data:

\[ \Delta H = mC_p(T_2 - T_1) \]

For natural gas, \( c_p = 0.56 \text{ Btu/lbm}^\circ\text{F} \), \( c_v = 0.44 \text{ Btu/lbm}^\circ\text{F} \), \( k = 1.27 \)

Mass flow rate = \( \rho Q \)
By law of conservation of mass, mass flowrate is constant across compressors but volume flowrate changes
Density at any section can be calculated from

\[ \rho = 2.7 \frac{p\gamma}{zT} \]
Example
In a 4 stage compressor, the suction pressure at the first and third stage are 100 psi and 900 psi. Intercoolers cool the gas back to 60 F. Calculate stages 1 and 2 discharge volume flowrate and the amount of heat removed by each intercooler per day for a gas flowrate of 900 Mscf/d at stage 1 inlet. Gas specific gravity is 0.65 and suction temperature is 60 F. k=1.3.

\[
R_c = \sqrt{\frac{900}{100}} = 3
\]

\[
P_{1s} = 100, \quad P_{1d} = 300
\]

\[
\frac{T_{1d}}{(60+460)} = (3)^{\frac{0.3}{1.3}} = 1.2886 \quad T_{1d} = 670 \text{ R} = 210 \text{ F}
\]
From Brill-Beggs,

\( P_{1s} = 100 \text{ psi}, \ T_{1s} = 60 \text{ F}, \ z_{1s} = 0.9844 \)

\( P_{1d} = 300 \text{ psi}, \ T_{1d} = 210 \text{ F}, \ z_{1d} = 0.9796 \)

\( P_{2d} = 900, \ T_{2d} = 210, \ z_{2d} = 0.9405 \)

\( P_{3d} = 2700, \ T_{3d} = 210, \ z_{3d} = 0.8825 \)

\( P_{4d} = 8100, \ T_{4d} = 210, \ z_{4d} = 1.2369 \)

\[ \rho_{1s} = 2.7 \frac{P\gamma}{zT} = \frac{2.7 \times 100 \times 0.65}{0.9844 \times 520} = 0.3428 \text{ lbm/ft}^3 \]

\[ m_{1s} = \rho Q = 0.3428 \times 900000 = 308563.6 \text{ lbm/d} \]

\[ m_{1d} = m_{2d} = m_{3d} = m_{1s} = 308563.6 \text{ lbm/d} \]

\[ \Delta H = mC_p(T_2 - T_1) \]

\[ \Delta H_{1 \rightarrow 2} = 308563.6 \times 0.56 \times (210 - 60) = 25,919,341.7 \text{ Btu/d} \]

\( \rho_{1d} = 2.7 \times 300 \times 0.65/0.9796/670 = 0.80219 \)

\( Q_{1d} = m_{1d}/\rho_{1d} = 308563.6/0.80219 = 384,654 \text{ scf/d} \)

\( \rho_{2d} = 2.7 \times 900 \times 0.65/0.9405/670 = 2.5066 \)

\( Q_{2d} = m_{2d}/\rho_{2d} = 308563.6/0.80219 = 123,100 \text{ scf/d} \)

\( \rho_{3d} = 2.7 \times 2700 \times 0.65/0.8825/670 = 8.014 \)

\( Q_{3d} = m_{3d}/\rho_{3d} = 308563.6/8.014 = 38,503 \text{ scf/d} \)

\( \rho_{4d} = 2.7 \times 8100 \times 0.65/1.2369/670 = 17.1535 \)

\( Q_{4d} = m_{4d}/\rho_{4d} = 308563.6/8.014 = 17,988 \text{ scf/d} \)
Chapter 11:
Volumetric Measurement
Allocation

Metering and allocation services are essential in order to guarantee precision and reliability and reduce costly errors in the oil and gas industry. Utilizing a common oil and gas pipeline or shared infrastructure brings the challenge of maintaining precise volume measurements, as even the smallest inaccuracy can come at a high cost.

In the petroleum industry, allocation refers to practices of breaking down measures of quantities of extracted hydrocarbons across various contributing sources. Allocation aids the attribution of ownerships of hydrocarbons as each contributing element to a commingled flow or to a storage of petroleum may have a unique ownership. Contributing sources in this context are typically producing petroleum wells delivering flows of petroleum or flows of natural gas to a commingled flow or storage. The terms hydrocarbon accounting and allocation are sometimes used interchangeably.

The term allocate is being used in the sense to denote distributing according to a plan. The term accounting is being used in the sense to denote justification of actions.
Sample configurations
In the illustration, a host field "A" processing plant separates, processes and exports hydrocarbon flows from field "A", and two satellite fields "B" and "C". **Legend:** Red M is *custody transfer meter (CTM)*, black M fiscal meter, gray M indicate optional allocation meter.

Allocation systems seen in the figure to the right: Fields "B" and "C" are each a basic allocation system where all the measured out-flow quantities from the field are allocated to the respective wells, and allocation can be conducted on all phases, oil, gas, water. ("B" and "C" have possible subsea plants only.) Field "A", an oil field where fluid of oil, produced water and associated gas is extracted. If free of pipeline connection, field "A" illustrates the typical allocation case. A processing plant splits crude oil into three fractions. Metering stations on the export point satisfy requirements for custody transfer, measuring instrument for flare gas is a fiscal measurement if subject to taxation, it depends on regulatory requirements. Measurement of well streams will typically have lower accuracy, or no meters are installed, when estimation processes are in use. All together, the collection of fields is a field allocation system in which contributions in sales products are allocated to each of the three fields.
Metering Stations

Although primarily utilized to measure the volume, quality, and consistency of product for billing purposes and delivery receipts, storage tank monitoring and product metering can be used with line pressure monitors to verify that pipeline integrity has not been compromised. Any discrepancy could indicate some sort of system leak. Typically there is some “shrinkage” in volume when products are transferred from pipeline to tanks to pipeline. Systems and processes are in place to determine when the shrinkage observed is outside expected values.
Meter Selection

Flow meters for the measurements in the oil and gas upstream industry are chosen based on type of measurement, performance and accuracy requirements, and the type of medium to be measured. Available meters in the market are characterized by properties such as accuracy, operational rangeability: flowrate, viscosity, velocity, pressure and temperature conditions, durability and demand with respect to calibration and monitoring, the ability to withstand contaminants, injected chemicals, salty and acidic environment. For the application of custody transfer measurements of fluid hydrocarbons, positive displacement meters and turbine meters have been preferred. For gas metering, gas orifice meters and ultrasonic flow meters are common. Coriolis meters are in use for liquid measurements, but can also take gas measurement applications.

All flowmeters can generally be classified, in terms of measurement techniques, as differential pressure or non-differential pressure. They are available for liquid, dry gas, and wet gas.
Natural Gas Metering

Natural gas is transported in pipelines with continuous flow from the gas field processing to its ultimate user. Accurate measurement of the total quantity of gas that has passed through a given section of pipe over a period of time is of paramount importance to both gas sellers and purchasers. The commonly used method of measuring natural gas is by volume. Because natural gas is compressible (volume depends on pressure and temperature), to measure gas in meaningful terms by the volume method, first specifying the base, or standard, pressure and temperature is of fundamental importance. In other words, the pressure and temperature of the reference or base cubic foot must be established. Most operators account for gas in units of 1,000 cubic feet at predefined standard conditions (pressure and temperature), commonly referred to as one Mscf. However, the standard condition is defined differently from area to area. Since 1967, the American Petroleum Institute (API) and the American Gas Association (AGA) have been using 14.73 psia and 60 0F as their standard conditions.
Wet Gas Metering

Natural gas produced from wells is usually not dry, but contains small quantities of liquid. Strictly speaking, “wet gas” refers to the presence of hydrocarbons heavier than ethane which, at reduced temperature and pressure conditions, tend to condense and form liquid in the upstream processing plant. The term “wet gas” is further reserved for processes where the proportion of liquid phase is no greater than about 5% by volume (or equivalently that the gas void fraction GVF is greater than 95%). However, water vapor condensing to water is often an additional liquid component of wet gas, and in mature wells ground water may find its way into the reservoir. Overall, therefore, wet gas is usually viewed as a three-phase stream consisting of gas, condensate and water. The task of a wet gas metering system is to measure the flow rates of each of these streams individually. A common simplification is to consider only two phases, gas and liquid, and to distinguish between the liquid components at a later stage in the production process.

Currently, there are three main approaches to wet gas metering. The first is to physically separate the streams before metering them individually using conventional single phase instrumentation. The second is to use a single phase meter (typically based on the differential-pressure principle, such as an orifice plate or a V-cone) on the wet gas stream, and to compensate the reading for the errors induced by the effects of wet gas. The third approach, adopted by a number of specialist suppliers, is to develop (often very expensive) truly multi-phase meters.
What measurements are needed or important?
- Gas flow rate only?
- Gas + liquid flow rate?
- Gas + liquid hydrocarbon + water flow rates?

**Wet gas metering options**

- Single-phase meter
- Two-phase meter
- Three-phase meter

The Murdock correlation is widely accepted within the industry as providing a usable correction to the DP/OP over-read:

\[
q_g = \frac{q_{ip}}{1 + 1.26X_{LM}} \]

\[
X_{LM} = \frac{\dot{m}_l}{\dot{m}_g} \sqrt{\frac{\rho_g}{\rho_l}}
\]

- Single-phase meter option allows for the measurement of the gas flow rate only, but the effect of the liquid on the meter response should be accounted for.
  Single-phase meters can generally be divided into those using *differential pressure* techniques and *non-differential pressure* techniques.
- Two- and three-phase meters provide information on the gas and total liquid flow rates or the gas, liquid hydrocarbon and water flow rates.
Differential Pressure Meters

Differential pressure (DP) meters are one of the most commonly used single-phase meter types available for flow measurement.

When a differential pressure flowmeter is used in wet-gas conditions the meter tends to ‘over-read’ the amount of gas passing through it. This means that the estimated quantity of gas determined by the flow meter is higher than the actual amount passing through it. Therefore the meter response must be ‘corrected’ to provide the actual gas mass flow rate.

The over-reading is defined as the uncorrected gas mass flow rate measured in wet-gas conditions, divided by the actual gas mass flow rate that would be obtained if the gas flowed alone in the pipe.

\[
Over\ -\ reading = \frac{\text{gas mass flowrate measured in wet - gas conditions}}{\text{gas mass flowrate measured in dry - gas conditions}}
\]

\[
Over\text{-reading} \approx \sqrt{\frac{\text{differential pressure in wet gas}}{\text{differential pressure in dry gas}}}
\]
Differential pressure meters commonly used are:
- Venturi tubes
- V-cones or cone-type meters
- Orifice plates

**Orifice Meter and Venturi tubes**

Orifice meters are the most common equipment used in the natural gas industry for measurement of natural gas flow rate.

An orifice meter consists of a thin flat plate with an accurately machined circular hole that is centered in a pair of flanges or other plate-holding device in a straight section of smooth pipe. Pressure tap connections are provided on the upstream and downstream sides of the plate so that the pressure drop or differential pressure may be measured.
Pressure Taps Location

There is a pressure tap upstream from the orifice plate and another just downstream. There are in general four methods for placing the taps. The coefficient of a meter depends on the position of the taps.

- **Flange tapping** - Pressure tap location 1 inch upstream and 1 inch downstream from face of orifice
- **Corner tapping** - Pressure tapping points are at the flange placed immediately upstream and downstream of the plate; convenient when the plate is provided with an orifice carrier incorporating tappings
- "**Vena Contracta**" tapping - Pressure tap location 1 pipe diameter (actual inside) upstream and 0.3 to 0.8 pipe diameter downstream from face of orifice
- **Pipe tapping** - Pressure tap location 2.5 times nominal pipe diameter upstream and 8 times nominal pipe diameter downstream from face of orifice
The Set Up
An orifice meter is composed of two major elements: 1) the primary element for producing differential pressure, and 2) the secondary element for measuring the pressures.

- The primary element consists of a meter tube, orifice plate-holding device, orifice plate, pressure taps, and straightening vanes which is a device that may be inserted in the upstream section of the meter tube to reduce swirling in the gas stream. The plate is typically a thin stainless steel plate about 3/16-in thick, with a hole in the center that is placed in the flow line. Placing an orifice in a pipe in which there is a gas flow causes a pressure difference across the orifice. This pressure difference and the absolute pressure in the line at a specified "tap" location are recorded continuously and are later translated into rate of flow.

- The secondary element is a gauge (or gauges) connected with tubing to the upstream and downstream pressure taps of the primary element. One part indicates or records the difference between the pressures on each side of the orifice plate and the other part indicates or records one of these pressures. Recording differential and static pressure gauges, using circulate charts with printed scales, are extensively used and they provide a permanent record. Integrating differential gauges are also made, in both the indicating and recording type that register the flow in uncorrected cubic ft.
Correct sizing and installation of orifice plates is absolutely essential, and is well documented in the International Standard ISO 5167.

Pressure tappings - Small bore pipes (referred to as impulse lines) connect the upstream and downstream pressure tappings of the orifice plate to a Differential Pressure or DP cell. The positioning of the pressure tappings can be varied.

Corner tappings - These are generally used on smaller orifice plates where space restrictions mean flanged tappings are difficult to manufacture. Usually on pipe diameters including or below DN50.

From the DP cell, the information may be fed to a flow indicator, or to a flow computer along with temperature and/or pressure data, to provide density compensation.
The advantages of the orifice meter are accuracy, ruggedness, simplicity, ease of installation and maintenance, range capacity, low cost, acceptance for gas measurement by the joint AGA-ASME committee, and availability of standard tables of meter factors.

Pipework requirement is for a minimum of five straight pipe diameters downstream of the orifice plate, to reduce the effects of disturbance caused by the pipework.
Principles

Orifice meter for gas is a similar concept as venturi meter used for liquid flow.

Orifice and venturi meters both function by sending pipe flow through a constricted area (the orifice plate or the venturi throat), as shown in the diagrams at the right. Due to the increased fluid velocity passing through the constriction, there will be a decreased pressure at that location. The pipe flow rate can then be calculated from the measured pressure difference between the undisturbed pipe flow and the flow through the constriction.
**General Equation**

The general equation for calculating flow rate through either an orifice or venturi meter is shown at the left, where the parameters in the equation and their units are as follows:

\[ Q = C_d A_o \sqrt{\frac{2 (P_1 - P_2)}{\rho (1 - \beta^4)}} \]

- **Q** is the flow rate through the pipe and through the meter (cfs – U.S. or m³/s – S.I.)
- **C_d** is the discharge coefficient, which is dimensionless
- **A_o** is the constricted area perpendicular to flow (ft² – U.S. or m² – S.I.)
- **P_1** is the undisturbed upstream pressure in the pipe (lb/ft² – U.S. or N/m² – S.I.)
- **P_2** is the pressure in the pipe at the constricted area, **A_o** (lb/ft² – U.S. or N/m² – S.I.)
- **β = D_2/D_1** = (diam. at A₂/pipe diam.), which is dimensionless
- **ρ** is the fluid density (slugs/ft³ – U.S. or kg/m³ – S.I.)
The discharge coefficient varies noticeably at low values of the Reynolds number.

<table>
<thead>
<tr>
<th>Diameter Ratio $d = D_2 / D_1$</th>
<th>Reynolds Number - $Re$</th>
<th>$10^4$</th>
<th>$10^5$</th>
<th>$10^6$</th>
<th>$10^7$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td></td>
<td>0.60</td>
<td>0.595</td>
<td>0.594</td>
<td>0.594</td>
</tr>
<tr>
<td>0.4</td>
<td></td>
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<td>0.603</td>
<td>0.598</td>
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<tr>
<td>0.5</td>
<td></td>
<td>0.62</td>
<td>0.608</td>
<td>0.603</td>
<td>0.603</td>
</tr>
<tr>
<td>0.6</td>
<td></td>
<td>0.63</td>
<td>0.61</td>
<td>0.608</td>
<td>0.608</td>
</tr>
<tr>
<td>0.7</td>
<td></td>
<td>0.64</td>
<td>0.614</td>
<td>0.609</td>
<td>0.609</td>
</tr>
</tbody>
</table>
Considerations

Venturi tubes are commonly selected instead of orifice plates to meter wet-gas flows as they are considered to be much more durable, more resistant to erosion and can withstand higher differential pressures without incurring damage to the device. Orifice plates, when used for wet-gas flow measurement, should ideally be easily accessible and checked regularly for damage or erosion as this affects the accuracy of the flow measurement. Orifice plates are mainly used for topside metering applications.

Orifice plates can be damaged by slugs of liquid impacting on their surface and bending the plate, and this can affect the flow measurement. It should be noted that the use of thicker orifice plates can withstand higher differential pressures and the impact force from liquid slugs. The maximum plate thickness permitted by the standard ISO 5167-22 is 0.05 times the pipe diameter, this is a plate thickness of 5 mm for a nominal four-inch pipe. For pipe diameters between 50 mm and 64 mm a plate thickness of up to 3.2 mm is allowed.
VCones Meter

V-cone flow meter, a kind of differential pressure flow meter, measures the flow rate through the throttling effect produced by V vertebral in the flow field. Compared with other differential pressure flow meters, V-cone flow meter has long-time high accuracy, good repeatability, less limitation of installation condition, lower abrasiveness, wider measurement range, more suitable for dirty medium, small pressure loss and so on. The V-Cone System has an advanced differential pressure flow sensing design. The flow meter features built-in flow conditioning for superior accuracy. With its built-in flow conditioning technology, the V-Cone also can be placed in relatively close proximity to elbows, valves, pumps, pipe U's, etc., where other flow measurement technologies would be impractical or inaccurate.

The amount of liquid present in wet gas can have a different effect on the over-reading response of different differential-pressure meters; for example the over-reading response for a V-cone may be different to that for a Venturi meter with the same amount of liquid present at identical flow conditions.
Non-Differential Pressure Meters

Positive Displacement Flowmeter

Positive displacement (PD) flowmeter technology is the only flow measurement technology that directly measures the volume of the fluid passing through the flowmeter. PD flowmeters achieve this by repeatedly entrapping fluid in order to measure its flow. PD Flow meters are volumetric flow measurement instruments that measure flow by passing a precise volume of fluid with each revolution. This process can be thought of as repeatedly filling a bucket with fluid before dumping the contents downstream. The number of times that the bucket is filled and emptied is indicative of the flow through the flowmeter.

Some Positive displacement flowmeters designs can measure gas flow although liquid flow applications are much more prevalent. In liquid service, increasing viscosity decreases slippage and increases the pressure drop across the flowmeter. Surprisingly, accuracy can actually improve at low flow conditions in a given positive displacement flowmeter when viscosity increases and slippage decreases.
There are many types of positive displacement flow meters, including: reciprocating piston, oscillating or rotary piston, bi-rotor types (spur gear, oval gear, helical gear, rotary vane), and nutating disc (wobble plate).

**Piston flow meters**

Piston flow meters are of single and multiple-piston types. The pistons displace fluid in the same way that a syringe operates. Each piston displacement captures the same amount of fluid.

**Gear flow meters**

Gear flow meters use two round gears that are mounted in overlapping compartments. The measured fluid is trapped in the voids of the gear teeth and transported from the inlet port to the outlet port as the fluid flow causes the gears to rotate.

**Helical flow meters**

Helical [Gear] Flow Meters use two screw-shaped rotors to chop the fluid stream into fixed displacement volumes. The rotors' orientation is in-line with the fluid flow path. These meters rotate with a very low pressure drop, and can turn at high rpm’s making them accurate over wide flow ranges and compatible with very high viscosity fluid applications.

http://www.maxmachinery.com/positive-displacement-flow-meters#video
Rotary vane meters consist of equally divided, rotating impellers, in two or more compartments, inside the meter's housings. The impellers are in continuous contact with the casing. A fixed volume of liquid is swept to the meter's outlet from each compartment as the impeller rotates.

Oval-gear meters have two rotating, oval-shaped gears with synchronized, close fitting teeth. A fixed quantity of liquid passes through the meter for each revolution.

Nutting disk meters have a moveable disk mounted on a concentric sphere located in spherical side-walled chambers. The pressure of the liquid passing through the measuring chamber causes the disk to rock (wobble) in a circulating path without rotating on its axis. The disk/sphere is the only moving part in the measuring chamber.
**Turbine flow meter**
The turbine flow meter (described as an axial turbine) translates the mechanical action of the turbine rotating in the liquid flow around an axis into a user-readable rate of flow. The turbine tends to have all the flow traveling around it. The turbine wheel is set in the path of a fluid stream. The flowing fluid impinges on the turbine blades, imparting a force to the blade surface and setting the rotor in motion. When a steady rotation speed has been reached, the speed is proportional to fluid velocity. Turbine flow meters are used for the measurement of natural gas and liquid flow. They are less accurate than displacement and jet meters at low flow rates, but the measuring element does not occupy or severely restrict the entire path of flow. The flow direction is generally straight through the meter, allowing for higher flow rates and less pressure loss than displacement-type meters. They are the meter of choice for large commercial users. They are accurate in normal working conditions but are greatly affected by the flow profile and fluid conditions.

Turbine meters should ideally never be used to meter wet gas as the meter can be damaged and the meter response is unpredictable.
Turbine Flow Meters Advantages:
- High degree of accuracy at low cost, especially when combined with a flow computer
- Flexibility in connecting to associated electronic readout devices for flow control and computer interface
- Wide flow rangeability
- Construction materials that permit use with many process fluids
- Simple, durable, field-repairable construction
- Operation over a wide range of temperatures and pressures

Turbine Flow Meters Disadvantages:
- Poor interchangeability from unit to unit
- Bearings depend on lubricity and cleanliness of process fluid
- Turbine blades are susceptible to wear and must be frequently calibrated
- Liquid applications may be suspect to problems involving cavitations, specific gravity, and viscosity
- Intended for clean fluid applications

They are less accurate than full flow models, typically +1 % and they measure the velocity at one point, so the insertion point is critical.
Ultrasonic flow meter
The measuring principle is based on the influence of the flowing fluid to the traveling time of sound. The sound is transmitted through the pipe and the transit time difference between the forward and backward directions is used to determine the flow velocity (transit time method). Two types of ultrasonic flow meter are in common use to measure pipe flow rate. They are the doppler ultrasonic flow meter and the transit time ultrasonic flow meter. Both types use transducers to transmit and/or receive ultrasonic waves in the process of pipe flow measurement.

Transit time method
The transit-time utilizes the propagation time of the ultrasonic signal in the fluid. A pair of transducers are installed on the outer surface of the pipe as shown in the diagram. Each transducer works alternatively as both transmitter and receiver of ultrasonic signals. When the ultrasonic signal is transmitted toward the upstream side against the flow direction, more propagation time is required (T1). On the other hand, when it is transmitted toward the downstream side with the flow direction, the propagation time is less (T2). That is, the signal is delayed or speeded up by the moving fluid. The difference in time between "T1" and "T2" is proportional to the flow velocity, and the flow volume can be calculated by multiplying it by the cross-sectional area, which is obtained by using the pipe diameter and wall thickness.
**Ultrasonic Doppler flow meter**

When a doppler ultrasonic flow meter is used for pipe flow measurement, one transducer transmits ultrasonic waves and the other transducer receives ultrasonic waves. The fluid for which pipe flow rate is being measured must have material like particles or entrained air that will reflect ultrasonic waves. The frequency of the transmitted beam of ultrasonic waves will be altered, or shifted, due to being reflected by the air bubbles or particles.

The frequency shift, which is proportional to the fluid flow rate through the meter, is measured by the receiving transducer. The receiving transducer can thus generate a signal that is proportional to flow rate.

The doppler and transit time ultrasonic flow meter both cause negligible pressure drop when in use for pipe flow measurement. The effect of fluid viscosity on pipe flow rate measurement is negligible for both types.

Both the doppler ultrasonic flow meter and the transit time ultrasonic flow meter are also available as an insert that mounts in the pipeline, much the same as other flow meters, like the magmeter. Both types of ultrasonic flow meter use two ultrasonic transducers that transmit and/or receive ultrasonic waves (frequency > 20 kHz) as part of the process of measuring the pipe flow rate.
**Coriolis mass flow meter**

A mass flow meter, also known as an *inertial flow meter* measures mass flow rate of a fluid traveling through a tube. The mass flow rate is the mass of the fluid traveling past a fixed point per unit time.

Coriolis mass flowmeters measure the force resulting from the acceleration caused by mass moving toward (or away from) a center of rotation. This effect can be experienced when riding a merry-go-round, where moving toward the center will cause a person to have to “lean into” the rotation so as to maintain balance. As related to flowmeters, the effect can be demonstrated by flowing water in a loop of flexible hose that is “swung” back and forth in front of the body with both hands. Because the water is flowing toward and away from the hands, opposite forces are generated and cause the hose to twist.

In a Coriolis mass flowmeter, the “swinging” is generated by vibrating the tube(s) in which the fluid flows. The amount of twist is proportional to the mass flow rate of fluid passing through the tube(s). Sensors and a Coriolis mass flowmeter transmitter are used to measure the twist and generate a linear flow signal.

Coriolis mass flowmeters measure the mass flow of liquids and gases. Because mass flow is measured, the measurement is not affected by fluid density changes. Coriolis mass flowmeters can measure flow extremely accurately so they are often used to measure high value products or the introduction of fluids that affect the production of high value products.

https://www.youtube.com/watch?v=PvXgaDoZr1E
The mass flow of a u-shaped coriolis flow meter is given as:

$$Q_m = \frac{K_u - I_u \omega^2}{2 K d^2 \tau}$$

where $K_u$ is the temperature dependent stiffness of the tube, $K$ a shape-dependent factor, $d$ the width, $\tau$ the time lag, $\omega$ the vibration frequency and $I_u$ the inertia of the tube. As the inertia of the tube depend on its contents, knowledge of the fluid density is needed for the calculation of an accurate mass flow rate.

Coriolis flow meter can be adapted to measure the density as well. The natural vibration frequency of the flow tubes depend on the combined mass of the tube and the fluid contained in it. By setting the tube in motion and measuring the natural frequency, the mass of the fluid contained in the tube can be deduced. Dividing the mass on the known volume of the tube gives us the *density* of the fluid. An instantaneous density measurement allows the calculation of flow in volume per time by dividing mass flow with density.

Both mass flow and density measurements depend on the vibration of the tube. Calibration is affected by changes in the rigidity of the flow tubes. Changes in temperature and pressure will cause the tube rigidity to change, but these can be compensated for through pressure and temperature zero and span compensation factors.

https://www.youtube.com/watch?v=PvXgaDoZr1E
A coriolis flow meter works on a very simple principle. Whenever a liquid is flowing through a pipe, the added mass of the liquid in the pipe increases the inertia of the pipe and makes it harder to move. Furthermore, a coriolis flow meter also utilizes the centrifugal force that acts on a liquid in a pipe when the pipe is rotated slightly. The combination of these two factors results in an interesting phenomenon wherein a bent u-shaped pipe oscillates in a particular manner when it is actuated as a liquid flows through it. As the liquid moves away from the axis of rotation, the moment of inertia of the pipe increases and the arm of the pipe that carries the liquid away from the center lags behind in the rotation. The arm of the pipe that brings the liquid back closer to the axis of rotation experiences a reduction in the moment of inertia and leads the rotation. The difference between the lag and the lead of both parts of the tube are used to calculate the mass flow rate.
**Wet Gas**: Most two-phase applications for Coriolis mass flow metering are for low Gas Void Fraction (GVF) conditions, i.e. where the process fluid is essentially liquid with relatively low levels of entrained air or gas. There are particular challenges associated with metering wet gas, where the GVF exceeds 95%. Established wet gas metering techniques are typically based on a differential pressure-type device (for example an orifice plate or V-cone). It is well-known that such devices over-read compared to a dry gas calibration; equations to correct the reading are available if the degree of gas “wetness” is known. For Coriolis mass flow metering of wet gas, two approaches are described. The natural extension of the low GVF techniques is to map the observed mass flow and density readings onto estimates of the flow rates of the gas and liquid components. The alternative is to use the Coriolis meter to estimate the degree of gas “wetness” (e.g. the Lockhart-Martinelli number) and to apply a conventional correlation (e.g. Murdock or Chisholm) to a differential pressure flow reading.

Coriolis flow meters have increasingly been used in multi-phase applications, but mostly in low GVF conditions. In providing two process measurements (mass flow and density) the Coriolis meter cannot provide true three-phase metering, except in conjunction with another technology (e.g. a water-cut or void fraction meter). A standalone Coriolis meter is, however, capable of acting as a two-phase meter, where the components are partitioned into a single liquid phase alongside the gas phase.

An undoubted advantage of using a Coriolis meter on wet gas duty is its ability to deal with any slugs of liquid that may be produced by the well. The rapid dynamic response of the meter ensures such (highly valuable condensate) slugs are metered accurately using conventional Coriolis two-phase metering techniques.
Calibration Techniques

Many factors can cause a flowmeter to lose calibration, including:
- buildup of deposits, minerals, oils, and solvents;
- wearing, breakage, or failure of internal mechanical parts;
- damaging impact;
- improper installation;
- modified piping configurations.

A flowmeter calibration, usually carried out by the manufacturer, adjusts the output of the meter to bring it back to a value within the specified accuracy tolerance.

Flowmeter calibrations are not absolute operations. A calibration compares a flowmeter measurement relative to a standard. The comparison establishes a relationship between what the flowmeter measures and what the standard measures. The standard consists of a system of pumps, pipes, fluids, instrumentation, quantity reference measurement, calculations, and operators—all combined to measure the quantity of fluid passing through the flowmeters in a unit of time.

Practical calibration techniques do not exist, and many methods depend heavily on operator skill. Locating good testing points in the pipeline is usually difficult. And flowmeters experiencing high flowrates often cannot be calibrated.

Drop Test or Volumetric Method

Calibrations using this technique determine the amount of liquid collected in a tank within a certain time interval. The amount collected can be measured by weight or volume. The uncertainties tend to be large, typically 5 to 10 percent. For example, suppose the diameter of the tank is 10 feet +/- two inches, and the level changes three feet +/- one inch. The dimensional uncertainties compute to a difference of 7,040 to 7,500 gallons, or 6.1 percent. In addition, the tank may not have a perfectly circular cross section or exactly plumb walls. Undetected leaks will further degrade accuracy.

The drop test diagram, typically involves volumes that are too large to be practical. Small uncertainties in the tank internal diameter or level can have a significant effect on calibration accuracy. Such tests are also time consuming.

In the drop test, calibration engineers determine the amount of liquid collected in a tank within a certain time interval.
Ultrasonic Clamp-On Meters

The user can install clamp-on ultrasonic transducers to the outside wall of a pipe and take measurements of flowrate to compare with readings of a flowmeter to be calibrated. These transit-time flowmeters measure the time difference between ultrasonic beams moving with and against the fluid flow. This time difference, combined with knowledge of the pipe’s internal diameter and the distance between the two ultrasonic transducers, permits a calculation of the volumetric flowrate through the pipe.

The best measurement accuracies possible with clamp-on ultrasonic flowmeters are 2 percent to 5 percent. But many other unknown factors generally result in lesser accuracies—5 to 10 percent. The three major sources of error include the pipe’s internal diameter, the flow velocity profile, and acoustic interference.
Insertion Probes

Insertion probes, which measure fluid velocity at a point within a pipe’s cross-section, can check the performance of an installed full-bore meter. An insertion flowmeter, measures the fluid velocity at a point. It is unaware of surrounding flow velocities outside of the immediate location of the probe tip. The user or a secondary device must calculate the volumetric flowrate based on knowledge of the flow profile within the pipe. Measurement accuracy ranges from 2 to 5 percent. This technique works best for a fully developed flow profile at the measuring location, usually achieved by installing the probe after a long length of straight pipe. The proper straight length depends on the nature of the upstream disturbances to the flow.

Sources of inaccuracy with insertion probes include: errors in internal pipe diameter, cross-sectional area, and pipe ovality, pulsating and unstable flows, varying flowrates between point measurements while determining profiles, errors and uncertainties in associated instrumentation; and particulate material in the fluid.
Tracer Methods

Tracer techniques for calibrating flowrates include the *transit-time* and the *dilution* methods. Attainable measurement accuracies range from 2 to 5 percent. Using the transit-time method, engineers inject a pulse of tracer fluid into the main flow stream and measure the time taken for the tracer to pass between two detection points. Since the volume of the pipe between the detectors is known, they can determine the volumetric flowrate. Some disadvantages include:

- not suitable for sluggish or slow moving flows;
- difficulties in determining the volume between detectors; and
- often requires many measurements, which can be time consuming.

Transit-time tracer calibrations measure the time the injected tracer fluid passes between two detectors.

In the dilution tracer calibration technique, the fluid flowrate is a function of the tracer injection rate and its downstream concentration.
Hydraulic Model

For some piping flow situations, engineers may find it difficult to calibrate the flow measurement system using either the dilution or volumetric tracer technique. In some cases, testing would potentially result in a release of an unacceptable contaminant loading to the environment. For these situations, engineers may be able to construct a hydraulic model of the flow system and then run calibration tests on the model under laboratory conditions. They would design the hydraulic model based on the principle of hydraulic similitude. With this approach, the model represents a geometric reduction of the actual flow measurement system. Engineers should pick a scale factor that provides model flows as close as practical to actual flows. Of course the model must be consistent with pumping capacity available at the testing facility.

The hydraulic model is constructed based on field-measured dimensions that are confirmed before construction. Common construction materials for a hydraulic model are wood and steel. In laboratory testing facilities, flowrate through the model is usually determined by applying the volumetric tracer method. Measurement accuracy ranges from 10 to 15 percent.

In the case of the reference meter in series, one flowmeter verifies another
Chapter 12: Natural Gas Transportation
Introduction

Advances in exploration and production have helped to locate and recover a supply of oil and natural gas from major reserves across the globe. At the same time, demand for petroleum-based products has grown in every corner of the world. But supply and demand are rarely concentrated in the same place. Transportation therefore is vital to ensuring the reliable and affordable flow of petroleum we all count on to fuel our cars, heat our homes and improve the quality of our lives.

Tankers and pipelines are proven, efficient and economical means of connecting petroleum supply and demand. Supply-end pipelines carry crude oil from well to a loading terminal at a port. Tankers then carry the crude oil directly to demand-side pipelines that connect to the refineries that convert the raw material into useful products.
Natural Gas Pipelines

Natural gas travels from the wellhead to end consumers through a series of pipelines. These pipelines -- including flowlines, gathering lines, transmission lines, distribution lines, and service lines - carry gas at varying pressures. The higher the pressure of gas in a pipeline, the more potentially dangerous an accident with that pipeline could be.

Pipelines are usually buried underground. Pipeline markers, such as those shown at right, do not always sit directly above the pipelines. For safety before digging, dial 811 to learn whether any pipelines are buried nearby.
Flowlines

- Flowlines connect to a single wellhead in a producing field. Flowlines move natural gas from the wellhead to nearby storage tanks, transmission compressor stations, or processing plant booster stations.
- Flowlines are relatively narrow pipes that carry unodorized raw gas at a pressure of about 250 psi.
- Typically, flowlines are buried 4 ft underground.
- Flowlines can corrode, especially if they are carrying wet gas. Flowlines are also prone to methane leakage. According to the EPA, "Methane leakage from flowlines is one of the largest sources of emissions in the gas industry."

Gathering Lines

- Gathering lines collect gas from multiple flowlines and move it to centralized points, such as processing facilities, tanks, or marine docks.
- Gathering lines are medium size steel pipes (usually under 18" diameter) that carry unodorized, raw gas at a pressure of approximately 715 psi.
- Typically, gathering lines are buried 4 ft underground.
- Gathering lines carry corrosive content that can affect pipeline integrity within a few years.
Transmission Pipelines

- Transmission pipelines carry natural gas across long distances and occasionally across interstate boundaries, usually to and from compressors or to a distribution center or storage facility.
- Transmission lines are large steel pipes (usually 2" to 42" in diameter; most often more than 10" diameter) that are federally regulated. They carry unodorized gas at a pressure of about 200 to 1,200 psi.
- Transmission pipelines can fail due to: seam failures, corrosion, materials failure, or defective welding.

Distribution Pipelines

- Distribution pipelines, also known as "mains," are the middle step between high pressure transmission lines and low pressure service lines; they move the gas close to cities. Distribution pipelines operate at an intermediate pressure.
- Distribution pipelines are small to medium sized pipes (2" to 24" in diameter) that are federally regulated and carry odorized gas at varying pressure levels, from as little as 0.3 up to 200 psi.
- Distribution pipelines typically operate below their carrying capacity. Distribution pipelines are made from a variety of materials, including steel, cast iron, plastic, and occasionally copper.
Service Pipelines

- Service pipelines connect to a meter that delivers natural gas to individual customers.
- Service pipelines are narrow pipes (usually less than 2" diameter) that carry odorized gas at low pressures, such as 6 psi. Service pipelines are typically made from plastic, steel, or copper.

Main Pipeline Design

A good pipeline design should be a compromise between the cost of pipe in the ground and the cost of all the compressor stations. As a general rule, pipe in the ground is cheaper than compressors. Costs should be obtained from the pipe mills and from compressor engine builders and gas turbine suppliers. Computer program can be used to compare the overall costs of the entire system.
Safety Regulations

The modern pipeline design engineer must take into consideration many new factors – for instance, the federal Gas Pipeline Safety Rules, 49CFR Parts 191, 192 and 193. These include requirements such as maximum spacing for mainline shut-off valves, heavier wall thickness in populated areas and some design at 50% of SMYS (specified minimum yield strength).

Most states have their own pipeline safety rules which can be more stringent than the federal rules. In addition, there are EPA regulations that are necessary to be complied with such as an environmental impact statement for the entire system, limits on exhaust emissions, right-of-way screening before excavation, etc. Your final design must comply with all such regulations.
Route Selection

A major pipeline will probably have several points of gas production where natural gas is to enter the system. A gathering system may be needed to bring it all to a common point. If the gas contains a lot of liquids, an LPG stripping plant may be required as may a desulfurization plant. In any event, a starting and stopping point for the mainline must be determined. The route of the mainline must now be chosen. A straight line drawn on a map connecting the two points is a good way to start.

Then fly the line in a chopper and avoid as many problem areas as possible. Such areas might be subdivisions, schools, churches and other places of public assembly. Natural obstacles such as rivers, lakes, canyons, etc., should be avoided. In some cases, it may be necessary to go through a subdivision. Federal rules require that the wall thickness of the mainline pipe be such that the steel will not be stressed more than 50% of its SMYS.

The purchaser of the pipe specifies the SMYS when he orders the pipe. For example, in X grades of pipe SMYS X70 means 70,000 psi SMYS, X60 means 60,000.
After the route has been selected, aerial photographs should be taken and a house count done for every mile of right-of-way at a width of 660 feet on either side of the line.
The class location (Part 192.5 of CFR49) is determined by counting the houses. For each mile of pipe within the strip of 1,320 feet (660 on either side of the line) the class location is as follows:

<table>
<thead>
<tr>
<th>No. houses per mile</th>
<th>Class Location</th>
<th>Stress Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 or less</td>
<td>1</td>
<td>72%</td>
</tr>
<tr>
<td>10 to 46</td>
<td>2</td>
<td>60%</td>
</tr>
<tr>
<td>46 or more</td>
<td>3</td>
<td>50%</td>
</tr>
<tr>
<td>4-story buildings</td>
<td>4</td>
<td>40%</td>
</tr>
</tbody>
</table>

**Class 1 location**

A Class 1 location is any 1-mile section of pipeline that has 10 or fewer buildings intended for human occupancy. This includes areas such as: • Wastelands • Deserts • Rugged mountains • Grazing land • Farmland • Sparsely populated areas

**Class 1, division 1 location**

This is a Class 1 location where the design factor, \( F \), of the pipe is greater than 0.72 but equal to or less than 0.80 and which has been hydrostatically tested to 1.25 times the maximum operating pressure.
Class 1, division 2 location
This is a Class 1 location where the design factor, $F$, of the pipe is equal to or less than 0.72, and which has been tested to 1.1 times the maximum operating pressure.

Class 2 location
This is any 1-mile section of pipeline that has more than 10 but fewer than 46 buildings intended for human occupancy. This includes fringe areas around cities and towns, industrial areas, and ranch or country estates.

Class 3 location
This is any 1-mile section of pipeline that has 46 or more buildings intended for human occupancy except when a Class 4 Location prevails. This includes: • Suburban housing developments • Shopping centers • Residential areas • Industrial areas • Other populated areas not meeting Class 4 Location requirements

Class 4 location
This is any 1-mile section of pipeline where multistory buildings are prevalent, traffic is heavy or dense, and where there may be numerous other utilities underground. Multistory means four or more floors above ground including the first, or ground, floor. The depth of basements or number of basement floors is immaterial.
Comparisons of the different classes
In addition to the criteria previously presented, additional consideration must be given to the possible consequences of a failure near a concentration of people, such as that found in a church, school, multiple-dwelling unit, hospital, or recreational area of an organized character in a Class 1 or 2 location. If the facility is used infrequently, the requirements of the following paragraph need not be applied.

Pipelines near places of public assembly or concentrations of people such as churches, schools, multiple-dwelling-unit buildings, hospitals, or recreational areas of an organized nature in Class 1 and 2 locations shall meet requirements for the Class 3 location. 50% stress level is also required for special locations such as: Offshore, Station yards, Within 300 feet of any building with human occupancy of 20 or more such as playgrounds, recreation areas, outdoor theaters, or any place of public assembly.

The concentration of people previously referred to is not intended to include groups fewer than 20 people per instance or location but is intended to cover people in an outside area as well as in a building.
**Pipe Selection**

The design pressure equation for steel pipe is:

\[
P = \frac{2stf}{D}
\]

where

- \(P\) = pressure in psig
- \(S\) = SMYS
- \(D\) = nominal outside diameter of pipe in inches
- \(t\) = nominal wall thickness in inches
- \(f\) = stress level factor

\[
t = \frac{PD}{2sf}
\]

There are standard wall thicknesses available from pipe mills. Non-standard thicknesses can be obtained but require special orders and prices. Having determined the miles of each wall thickness needed, bids may now be taken from qualified pipe mills which will supply the pipe. The pipe should go to a coating mill before being shipped to the job site.
Coatings for buried pipelines have been vastly improved. Plastic enamel-type powder sprayed onto a pipe heated to more than 400 degrees F gives an impervious glass smooth coat which prevents corrosion of the outer wall. If this same smooth coating is applied to the inner wall it will reduce the friction factor and result in a larger gas flow for the same pressure drop. Furthermore, this internal coating can be applied at the same time as the external coating while the pipe is hot.

The maximum allowable operating pressure (MAOP) must now be determined. Obviously, the higher the pressure, the more gas you can compress. However, valves, fittings and compressors may not be available for higher pressures: 1,000 psig equipment is available whereas 1,200 psig may not be. Check with the suppliers of these items. The grade of steel must also be decided. X70 is being used throughout the industry; X80 has been used in a test section, but its use may create welding problems and it may not be available in large quantities.

Next, the pipe diameter must be chosen. Here again, the bigger the pipe, the more gas it will move. However, the same precaution should be used: 48-inch valves are available, but fittings, especially for 50% stress level, may not be.
Compression ratio

First we need to know the quantity of gas to be moved. For example, assume a quantity of 500,000 Mcf/d to be moved through a 30-inch pipe, MAOP of 1,000 psig. Try a station spacing of 60 miles. Use any of the following to determine the pressure drop between compressor stations:

\[
P_1^2 - P_2^2 = \frac{25.2f zTL\gamma Q^2}{D^5}
\]

\[
P1 - P2 = \frac{fL\rho v^2}{2D}
\]

where:
P1 = station discharge pressure, psi
P2= next station suction pressure, psi
\(\gamma\) = gas specific gravity
Q = flowrate in MMscf/d
D = inside diameter, in
L = distance between stations, ft
v = velocity, ft/s
f = Moody friction factor
T = temperature, R
z = compressibility factor
For the example: MAOP = 1000 psi, L = 60 miles, D = 29 in, γ = 0.61, 
Q = 500,000 Mscf/d, T_{in} = 60 F, Pipe roughness = .0006

Find compression ratio

\[Z = 0.8415 \text{ (Brill-Beggs)}\]
\[f = 0.0155 \text{ (Moody chart)}\]

\[P_1^2 - P_2^2 = \frac{25.2 \times 0.0175 \times 0.8415 \times 520 \times 60 \times 5280 \times 0.61 \times 500^2}{29^5}\]

\[1000^2 - P_2^2 = 454528.46\]

\[P_2 = 738.56 \text{ psi}\]
\[\frac{p_1}{p_2} = \frac{1000}{738.56} = 1.354\]

**Compressor Selection**

A compression ratio of 1.354 is a good one for centrifugal compressors driven by gas turbines. Therefore, the 60-mile station spacing is reasonable. If higher compression ratios are needed, then piston-type compressors should be considered.

The brake horsepower (BHP) needs to be calculated first in order to select the best compressor for the job.
Brake Horsepower = 22 * (ratio/stage) * (Number of Stages) * (MMSCFD) * F
where F = 1.0 for a single stage, 1.08 for a 2-stage and 1.1 for a 3-stage.

For the example just used above, 14,893 brake horsepower is required for a compression ratio of 1.354.

Another Example
Calculate the BHP required to compress 5 MMscf/d gas at 14.7 psia and 70 F, with an overall compression ratio of 7 considering 2-stage compression.

Compression ratio/stage = 7^{\frac{1}{2}} = 2.65

BHP = 22 x 2.65 x 2 x 5 x 1.08 = 629.64

Changes in gas supply and inlet pressure are likely to occur at the first mainline compressor station as well as at the last compressor station. Piston-type compressors can handle such changes more easily than centrifugals; therefore, it would be wise to design the system with piston-type compressors at both the first and last stations.

For compressor stations in remote areas, electric power may not be available. Such stations can generate their own power using small gas-fired engine generators or by attaching a generator to the flywheel of one of the compressor engines.
Road Transportation

Natural gas producers are committed to addressing transportation related concerns and are required to develop comprehensive road management plans with each state’s department of transportation. The transportation of equipment, materials and water is critical to developing this abundant natural resource. Roadways in areas that have active operations must be capable of supporting this additional traffic and are often upgraded and repaired at the expense of the natural gas industry, as outlined in state-approved road management plans.

Many roads in communities with active natural gas development will be substantially improved and continuously maintained by the industry, providing a valuable benefit to landowners and municipalities. These companies also work with the government to bond roads, providing an assured source of funding in the event of damages.

Liquefied Natural Gas (LNG) or Compressed Natural Gas (CNG) can be transported by road. CNG vehicles are used for bulk fuel hauling from fuel terminals to the customers.