Field Handling of Natural Gas

Fourth Edition

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1 Characteristics of natural gas

Natural gas is a mixture of hydrocarbon gases, together with some impurities that are the result of decomposed organic material. The impurities also include water vapor and heavier hydrocarbons. When raw natural gas is withdrawn from underground reservoirs to supply energy demands, these impurities are considered objectionable and are removed by various processing schemes. The hydrocarbon gases normally found in natural gas are methane, ethane, propane, butanes, pentanes, and small amounts of hexanes, heptanes, octanes, and heavier gases. Usually the ethane and heavier fractions are removed for additional processing because of their high market value as gasoline blending stock and chemical plant raw feedstock. What usually reaches the transmission line for sale as natural gas is a mixture of methane and ethane with some small percentage of propane. Methane is the largest component (usually 95% to 98%).

Composition of natural gas

Natural gas has been defined as a mixture of hydrocarbon gases and impurities. No one mixture can be referred to as natural gas; each gas stream produced has its own composition. Even two gas wells from the same reservoir may have different compositions. Examples of some typical natural gas streams are provided in table 1.1 to show the range of composition that is naturally produced.

Well stream no. 1 is typical of an associated gas; that is, gas produced with crude oil. Well streams no. 2 and no. 3 are typical low-pressure and high-pressure gases of the nonassociated type. Not only is there a wide variety of natural gas compositions, but also each gas stream produced from a natural gas reservoir can change composition as the reservoir is depleted. Well analyses should be checked periodically, since it may be necessary to change the equipment used for production in order to satisfy the new composition of the gas.

TABLE 1.1
Typical Natural Gas Analyses

Component	Well No. 1 Mol Percent	Well No. 2 Mol Percent	Well No. 3 Mol Percent
Methane	27.52	71.01	91.25
Ethane	16.34	13.09	3.61
i-Butane	29.18	7.91	1.37
,-Butane	5.37	1.68	0.31
n-Butane	17.HI	2.09	0.44
i-Pentane	2.18	1,17	0.16
n-Pentene	1.72	1.22	0.17
Hexane	0.47	1.02	0.27
Heptanes and Heavier	0.04	0.81	2.42
Carbon Dioxide	0.00	0.00	0.00
Hydrogen Sulfide	0.00	0.00	0.00
Nitrogen	0.00	0.00	0.00
Total	100.00	100.00	100.00

Note: Production from many wells will contain small quantities of carbon dioxide, hydrogen sulfide, and nitrogen.

Natural gas is normally thought of as being a mixture of straight-chain, or paraffin, hydrocarbon gases. However, cyclic and aromatic hydrocarbon gases (cyclic compounds) are occasionally found in the mixture. The terms *straight-chain* and *cyclic* refer to the molecular structure. Methane, ethane, propane, butanes, pentanes, and so forth are straight-chain, or paraffinic, compounds. The molecular structure of these and the cyclic compounds are shown for comparison in figure 1.1.

Impurities found in natural gas must be removed because they cause difficulties in

2 Natural gas production

Oil and gas are known as fossil fuels, and the most prevalent theory of their origin is organic- that is, that they originated a million years ago and earlier from living organisms in ancient seas. Falling to the sea:fioor as they died, these organisms built accumulations that eventually became overlain by other sediment and, because of the pressure exerted by both water and sediment, the organic material gradually became transformed into petroleum and natural gas.

Oil and gas accumulations

For oil and gas to accumulate, there must first be a source for their creation; second, a porous bed must exist, one which is permeable enough to permit the oil and gas to flow through it - the reservoir rock; and finally, there must be a trap, which is a barrier to fluid flow so that the petroleum and natural gas may accumulate.

Migration

It is generally accepted that any present accumulation of oil and gas is a result of migration of widely dispersed and relatively small individual quantities of hydrocarbons to a more concentrated deposit, such as is found in a reservoir. In some cases, the source material may be in close proximity to the present pool. However, it is believed that in most instances the organic source material from which petroleum and natural gas are formed is widely disseminated in the sediments and that accumulations are the result of the combination of small portions from near and far.

Several natural forces and conditions that assist such migration include (1) compaction of source beds by the weight of the overlying rock, providing a driving force tending to expel fluids through pore channels or fractures to regions of lower pressure and normally shallower depth; (2) gravitational separation of gas, oil, and water in porous rocks that are usually water saturated; (3) pressure differential from any cause between two interconnected points in a permeable medium; and (4) faulting of the earth's strata.

Reservoirs

Accumulation of oil and gas into a commercial deposit requires (1) a reservoir to contain the oil and gas, along with some water, and (2) a trap, which retains the oil and gas in the reservoir until discovery.

A petroleum reservoir is a rock capable of containing oil, gas, and water. To be commercially productive, it must have sufficient thickness, areal extent, and pore space to contain an appreciable volume of hydrocarbons, and it must yield the contained fluids at a satisfactory rate when it is penetrated by a well.

Sandstones and carbonates are the most common reservoir rocks. In .order to contain fluids, they must have porosity. The porosity may be classified as (1) primary, that which is present in the original deposition, or (2) secondary, that which results from later physical or chemical changes, such as dolomitization, solution channels, or fracturing.

Porosity is expressed as the ratio of void space to the bulk volume of the rock, usually in percentage. Depending on the method of determination, porosity may represent either total or effective porosity. In many porous rocks, a number of blind or unconnected pores exists. *Effective porosity* refers

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Natural gas and liquid separation

A natural gas well stream as produced from a reservoir is a complex mixture of hundreds of different compounds of hydrogen and carbon, all with different densities, vapor pressures, and other physical characteristics. A typical well stream is a high-velocity, turbulent, constantly expanding mixture of gases and hydrocarbon liquids, intimately mixed with water vapor, free water, solids, and other contaminants. As it flows from the hot, high-pressure reservoir, the well stream is undergoing continuous pressure and temperature reduction. Gases evolve from the liquids, water vapor condenses, and some of the well stream changes in character from liquid to bubbles, mist, and free gas. The high-velocity gas is carrying liquid droplets, and the liquid is carrying gas bubbles.

Stated simply, field processing is for the purpose of removing and separating the well stream into salable gas and petroleum liquids, recovering the maximum amounts of each at the lowest possible overall cost. Field processing of natural gas actually consists of four basic processes:

1. Separation of the gas from entrained solids and free liquids such as crude oil, hydrocarbon condensate, and water
2. Conditioning the gas to remove other undesirable components, such as hydrogen sulfide or carbon dioxide
3. Conditioning the gas to remove condensable water vapor, which under certain conditions might cause hydrate formation
4. Processing the gas to remove condensable and recoverable hydrocarbon vapors

Conventional separators

Separation of well stream gas from free liquids is by far the most common of all field processing operations and, at the same time, one of the most critical. A properly designed separator will provide a clean separation of free gases from free hydrocarbon liquids. A well stream separator must-

1. cause a primary-phase separation of the mostly liquid hydrocarbons from those that are mostly gas;
2. refine the primary separation by removing most of the entrained liquid mist from the gas;
3. further refine the separation by removing the entrained gas from the liquid; and
4. discharge the separated gas and liquid from the vessel and ensure that no reentrainment of one into the other takes place.

If these functions are to be accomplished, the basic separator design must-

1. control and dissipate the energy of the well stream as it enters the separator;
2. ensure that the gas and liquid flow rates are low enough so that gravity segregation and vapor-liquid equilibrium can occur;
3. minimize turbulence in the gas section of the separator and reduce velocity;
4. control the accumulation of froths and foams in the vessel;
5. eliminate reentrainment of the separated gas and liquid;

4 Hydrates

Most natural gas contains substantial amounts of water vapor at the time it is produced from a well or separated from an associated crude oil stream. Water vapor must be removed from the gas stream because it will condense into liquid and may cause hydrate formation as the gas is cooled from the high reservoir temperature to the cooler surface temperature. Liquid water almost always accelerates corrosion, and the solid hydrates may pack solidly in gas gathering systems, resulting in partial or complete blocking of flow lines.

Hydrates are solid compounds that form as crystals and resemble snow in appearance. They are created by a reaction of natural gas with water, and, when formed, they are about 10 percent hydrocarbon and 90 percent water. Hydrates have a specific gravity of about 0.98 and will usually float in water and sink in hydrocarbon liquids. Water is always necessary for hydrate formation, as is some turbulence in the flowing gas stream.

Formation of hydrates

The temperature at which hydrates form depends on the actual composition of the gas and the pressure of the gas stream. Therefore, the chart shown in figure 4.1 cannot be completely accurate for all gases, but it is typical for many gass . The chart shows the water content in pounds of water per MMscf of saturated gas at any pressure or temperature. The dotted line crossing the family of curves shows the temperature at which hydrates will probably form at any given pressure. Note that hydrates form more easily at higher pressures. At 1,500 psia, for example, hydrates may form at 70°F, whereas at 200 psia, hydrates will not form unless the gas is cooled to about 39°F. Each curve on the chart shows the water content of a saturated gas at that pressure when the temperature is at any of the various points shown along the bottom of the chart. For example, at 100 psia and 60°F, each 1 million cubic feet of gas would contain about 130 pounds of water vapor. The same gas at 100 psia and 20°F (instead of 60°F) could hold only 30 lb per MMscf. At 0°F, this gas could hold only 13 lb per MMscf.

It can thus be seen that as a gas is cooled, it can hold less water in the vapor form. Therefore, cooling a gas will cause some of the water vapor to condense, with the balance remaining in the gas as water vapor. Pipeline specifications usually require that the water vapor content of natural gas be 7 lb per MMscf or less in order to minimize the problem of hydrate formation in the transmission lines from the field to the ultimate user. In some fields, hydrates form in the tubing and the wellhead valves, necessitating the application of heat down the hole to keep the well from freezing up. In most fields, fortunately, the temperature of the gas at the wellhead is 100°F or more; therefore, the hydrate problem does not usually begin until the gas passes through the Christmas tree.

Ground temperatures

A very important factor in the movement of gas saturated with water vapor is the retention of the heat that is in the gas when it is produced. The temperature is lowered at the wellhead when the gas is expanded through a choke to reduce the pressure and control the rate of flow. After passing the choke, the gas enters the gathering lines, which are cooled by

5 Dehydration of natural gas

The process whereby water vapor-and certain other vapors as well- are removed from natural gas by either absorption or adsorption is termed dehydration. The removal of water vapor by bubbling the gas countercurrently through certain liquids that have a special attraction or affinity for water is known as *absorption.* Removal by making the gas flow through a bed of granular solids that have an affinity for water is called *adsorption;* the water is retained on the surface of the particles. The vessel in which either absorption or adsorption takes place is called a *contactor,* or *sorber.* The liquid or the solid having affinity for water and used in the contactor in connection with either of the processes is called the *desiccant.*

The *dew point* of natural gas is that temperature at any specified pressure at which it is saturated with water vapor. Being saturated means that the gas contains in vapor form all the water possible at the specified pressure and temperature.

Two major types of dehydration equipment are in use at this time, namely, the *liquid desiccant* dehydrator and the *solid desiccant* dehydrator. Each has its special advantages and disadvantages and its own field of particular usefulness. Practically all of the gas moved through transmission lines is dehydrated by one or the other of these two methods.

Dew point depression

Hydrates do not form in a gas line unless the gas is saturated and contains still more water that, since it cannot be absorbed, takes the form of free water. At any specified pressure, hot gas takes more water vapor to reach the saturation point than does cool gas. This means that cool gas is saturated and also has some free water; it will absorb all of the free water when heated sufficiently at the same pressure. If heated above this point, cool gas will not only take up all the free water as water vapor and so prevent hydrate formation, but also will be undersaturated-that is, it will be capable of absorbing more water vapor than the gas is holding. For example, gas at 500 psia and 60°F at the saturation point contains 30 lb of water per 1 MMcf. The dew point of this gas is 60°F. Suppose this gas is going to be moved to New York in a transmission line with a temperature of 20°F. The saturation point will then be 7 lb of water per 1 MMcf. The original 30 lb of water, if left in the gas, will then exist in the form of 7 lb of water vapor and 23 lb of free water per 1 MMcf, if the pressure remains the same. This free water is a potential source of hydrates that may freeze and plug the line. Suppose that the gas is processed in a dehydration unit and the dew point is depressed 50°F. No free water will exist in the gas until the temperature is lowered more than 50°F from the original temperature of 60°F or until the temperature goes to 10°F or lower. Gas at 500 psia and 10°F contains about 5 lb of water vapor per 1 MMcf. Since this gas originally contained 30 lb of water vapor per MMcf, it will be necessary to remove *25* lb of water from each 1 MMcf in order to depress the dew point 50°F. In principle, this depression is the job of the dehydration unit. The problem presented has been purposely stated in oversimplified form to establish the principle of operation. Actual operating problems are not so simple.

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Miscellaneous gas conditioning

Natural gas well streams often contain hydrogen sulfide (H_2S) and carbon dioxide (CO_2). These two gases are called acid gases because in the presence of water they form acids or acidic solutions. These gases, particularly H_2S, are very undesirable contaminants, and unless they are present in very small quantities, they must be removed from a natural gas well stream.

Most pipeline specifications limit H_2S content to 0.25 grain per 100 cubic feet of gas. This is equivalent to about four parts per million. H_2S must be removed for several reasons, the most important being that it is a toxic and very poisonous gas and cannot be tolerated in gases that may be used for domestic fuels. H_2S in the presence of water is extremely corrosive and can cause premature failure of valves, pipelines, and pressure vessels. It can also cause catalyst poisoning in refinery vessels and requires many expensive precautionary measures to be taken.

The terms *sour crude* and *sour gas* refer to crude oil and gas that contain H_2S in amounts above acceptable industry limits. The terms *sweet crude* and *sweet gas* refer to oil and gas that do not contain H_2S or that have been treated to get rid of it.

Carbon dioxide removal is not always required, but most treating processes that remove H_2S will remove CO_2 also; therefore, the volume of CO_2 in the well stream must be added to the volume of H_2S to arrive at the total acid gas volume to be removed. CO_2 is corrosive in the presence of water, and as an inert gas has no heating value. In sufficient quantities, therefore, CO_2 might reduce the heating value (Btu/cf) below acceptable limits. Carbon dioxide removal may be required for gas going to cryogenic plants to prevent solidification of the CO_2.

Carbon disulfide (CS_2), carbonyl sulfide (COS), and mercaptans must also be considered in treating processes. Pipeline specifications normally allow 10 to 20 grains of total sulfur per 100 cubic feet of gas, including the 0.25 grain of H_2S. CS_2, COS, and mercaptans must be included in the total maximum allowable sulfur content.

Removal of acid gases

Several processes may be used to remove acid gases from natural gas. Some are selective for H_2S, others for CO_2. The oldest process, the iron sponge process, is also the most limited. It is a dry process using iron oxide (Fe_2O_3) impregnated on wood chips or shavings. It is usually used on low-concentration sour gas streams. The vessel can operate 30 to 60 days either without any regeneration or with the partial regeneration that can be effected with air passage through the vessel. The vessel must be recharged with new iron sponge material when gas sweetening is no longer possible.

The most widely used process in industry, the *alkanolamine process,* is a continuous-operation liquid process using absorption for the acid gas removal, with subsequent heat addition to strip the acid gas components from the absorbent solution. Most commonly used absorbing alkanolamine solutions are not selective and absorb total acid gas components. The process is particularly useful in order to obtain low acid gas residual concentrations, such as are required for gas transmission pipeline gas, chemical feedstocks, and domestic household and building heating usage. The type of process involved is chemical

7 Compressors and prime movers

A most common item of equipment used in the handling and transporting of gas is the compressor. Compressors may vary in size from small belt-driven units in the order of 50 hp to very large reciprocating or centrifugal units of 15,000 hp or more. The most common type of compressor is the gas-engine-driven reciprocating unit. However, gas-turbine-driven centrifugal units are coming into use more and more. Other types of drivers for reciprocating units are electric motors and steam turbines. These drivers are ordinarily used in special situations and are rarely found in field operations. Electric motors are normally difficult to justify, since electric power usually costs more than the fuel gas that would be saved. However, electric motors are being used in more and more applications where the exhaust emissions from gas engines or turbines would exceed environmental limits. Expansion turbines are used quite often in plants or refineries where a pressure drop in a fluid stream (gas, hot oil, etc.) can be utilized.

Reciprocating compressors

Drivers

The internal-combustion gas engine is the leading prime mover for gas compression service in the oil industry. The popularity of the gas engine in this field has been maintained primarily because of its overall efficiency, because of the availability of a clean, relatively low-cost fuel, and because manufacturers of this equipment have made gas engines and reciprocating compressors into compact integral units. Horsepower ratings and general design of modern gas engines are significantly different from the units manufactured a generation ago. Today, integral gas engine-compressor units are available from under 200 hp to 7,500 hp or more. Guaranteed thermal efficiencies of some of the gas engine-compressor units are now approaching 40 percent. For comparison, maximum thermal efficiency of a steam turbine is approximately 33 percent. Gas-turbine-engine thermal efficiency may be less than 25 percent, depending to a great extent on the utilization of the heat in the exhaust gases.

Gas engines may be classified in a number of ways including the following.

1. Combustion cycle
    - a. Four-stroke cycle
    - b. Two-stroke cycle
2. Power impulse
    - a. Single acting
    - b. Double acting
3. Cylinder arrangement
    - a. Vertical
    - b. Horizontal
    - c. V-type
    - d. Opposed
    - e. Radial
4. Speed
    - a. Low (100 to 250 rpm)
    - b. Intermediate (250 to 600 rpm)
    - c. High (600 to 1,200 rpm)

In general, the gas engines most commonly used now are both two- and four-stroke cycle units with single-acting power cylinders in a vertical or V-type arrangement, operating in the intermediate or high speed range. The smaller units connected to compressors by

8 Instruments and controls

Important variable quantities are associated with the production and handling of natural gas and any associated liquids-pressure, temperature, flow rate, and liquid level. How these variables are controlled is crucial to safety, operability, and accurate measurement of quantities of natural gas and associated liquids.

Some of the terms associated with instruments and controls should be learned. The *controlled variable* in a system is the variable whose value is the objective, the aim, of the control system. Its correct value is called the *set point* value. In field handling of natural gas the controlled variable may be any of the four mentioned in the paragraph above. Sometimes one or more of these variables may be used to aid in the control of the controlled variable. Used in that way they become *manipulated variables.* Should steam be used to heat water in a hot water system, *temperature* of the water is the *controlled variable,* steam is the *control agent,* and *flow* of steam the *manipulated variable.* Additionally, the valve that controls flow of steam is a *final control element,* the device that initially measures the water temperature is the *primary element,* and the hot water is the *controlled medium.*

Modes of control

Mode of control refers to the manner in which a manipulated variable is handled in order to regulate the controlled variable. By far the most commonly used mode is *on-off* action, in which the flow of the manipulated variable is at a maximum or at zero. The controls on domestic water heaters, heating and cooling systems are usually of this sort.

The *proportional* mode is popular in many process control systems. It provides continuous flow and responds to changes in the controlled variable, but it is not necessarily capable of maintaining the controlled variable at the set point.

Reset and *rate* modes usually work in conjunction with the proportional mode. Reset mode working with proportional mode (proportional-plus-reset) is capable of rather quickly returning the variable to the set point. Rate mode is used in process control in conjunction with proportional and reset (proportional-plus-reset-plus-rate). This arrangement provides a finer control, allowing less deviation from the set point, and generally a more rapid return to it. It is not needed in the vast majority of cases.

Measurement of controlled variables

Before a variable can be controlled its value must be measured or compared with its desired value in order to obtain an *error signal.* The error signal is the difference between the desired and the actual values of the controlled variable and is used to initiate corrective action by the controller. A large number of devices and instruments are capable of measuring or comparing the values of the several variables that are of interest in field handling of natural gas.

Pressure measurement

The *manometer* is a common instrument for measuring rather low values of pressure, from those well below zero gauge pressure to perhaps a few pounds per square inch gauge (psig}. The manometer is typically a U-shaped device made of glass tubing (fig. 8.1). The

9 Measurement of natural gas and gas liquids

Natural gas is a valuable asset and a superior fuel. Good business practices dictate the need for efficient handling of natural gas and natural gas liquids. Efficient handling of these products includes good measurement practices.

The volume of gas is the fundamental basis for settlement in most gas-sales transactions. Payments for royalties and taxes are usually based on measured volumes. Reports to state regulatory bodies and to the Federal Power Commission, when required, are based on volumes measured in the field. Gas, being a vapor, is not subject to conventional methods of storage in large quantities. Therefore, it must be measured instantaneously as it flows through a pipeline. Natural gas liquids may be measured as they flow through a line, or they may be stored and measured in the storage vessel.

Metering of fluids may be described as the practice of measuring volumes or rates of flow by actually passing the fluids through some type of meter. While metering is the most common method of determining volumes or rates of flow, other methods of measurement are sometimes used. For gas, these include calculation of the volume in a pipeline (i.e., line pack) or in storage on the basis of the line or storage volume and pressure; application of pipeline flow formulas; estimation from time and rate of usage factors; computation of compressed volumes from temperature, pressure, cylinder displacement, and compressor speed; and other similar techniques that are practical. For liquids, the gauging of storage tanks would be included.

A fluid flowing through a line can be measured by placing a constriction in the line to cause the pressure of the flowing fluid to drop as it passes the constriction. This pressure drop is called *differential pressure* (fig. 9.1). A direct relationship exists between the rate of flow and the amount of this pressure drop, or differential. This principle has been widely used and has been developed into a precise and accurate means of measuring fluids when all factors are taken into consideration and when ideal conditions for its use prevail. Because this principle is so widely used, the method that makes use of the principle known as *orifice measurement* will be given emphasis herein.

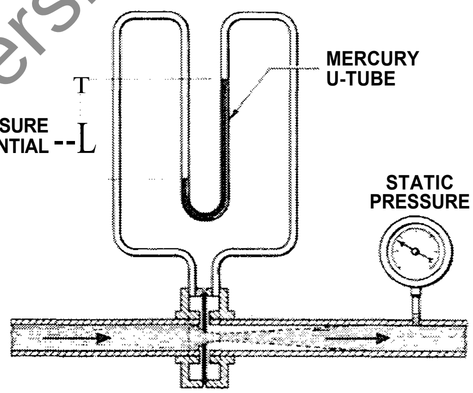

Figure 9.1. Diagram of the pressure drop across an orifice plate

Both gas and liquids may be measured by use of other measurement techniques including positive displacement meters, turbine meters, venturi meters, flow nozzles, critical flow provers, elbow meters, variable area meters (rotameters), and others. The selection of the measurement method to be used should be made only after careful analysis of several factors including the following:

1. accuracy desired;
2. expected useful life of the measuring device;
3. range of flow and temperature;
4. maintenance requirements;
5. power availability, if required;

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