

Lecture Two

Natural Gas Composition and Phase Behavior

2.1 Natural Gas Composition

Depending on where and from what type of reservoir the natural gas is produced, its composition can vary widely. Generally, it contains primarily methane (CH_4) with decreasing quantities of ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and pentane (C_5H_{12}). Some natural gas mixtures can also contain non-hydrocarbon gases such as carbon dioxide (CO_2), oxygen (O_2), nitrogen (N_2), hydrogen sulphide (H_2S), and traces of rare gases (Ar, He, Ne, Xe). No matter what the natural composition of gas is, the product delivered and finally used by the consumers is almost pure methane.

Table 2.1: Molecular Weights and Critical Properties of Pure Components of Natural Gases

Compound	Chemical Composition	Symbol (for calculations)	Molecular Weight	Critical Pressure (psi)	Critical Temp. (R)
Methane	CH_4	C_1	16.04	673	344
Ethane	C_2H_6	C_2	30.07	709	550
Propane	C_3H_8	C_3	44.09	618	666
iso-Butane	C_4H_{10}	i- C_4	58.12	530	733
n- Butane	C_4H_{10}	n- C_4	58.12	551	766
iso-Pentane	C_5H_{12}	i- C_5	72.15	482	830
n-Pentane	C_5H_{12}	n- C_5	72.15	485	847
n-Hexane	C_6H_{14}	n- C_6	86.17	434	915
n-Heptane	C_7H_{16}	n- C_7	100.2	397	973
n-Octane	C_8H_{18}	n- C_8	114.2	361	1024
Nitrogen	N_2	N_2	28.02	492	227
Carbon Dioxide	CO_2	CO_2	44.01	1,072	548
Hydrogen Sulfide	H_2S	H_2S	34.08	1,306	673

2.2 Phase Behavior

Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:

- ❖ The composition of the reservoir hydrocarbon mixture
- ❖ Initial reservoir pressure and temperature
- ❖ Pressure and temperature of the surface production

The conditions under which these phases exist are a matter of considerable practical importance. The experimental or the mathematical determinations of these conditions are conveniently expressed in different types of diagrams commonly called phase diagrams. One such diagram is called the pressure-temperature diagram.

2.2.1 Pressure-Temperature Diagram

Natural gas phase behavior is a function of pressure, temperature, and volume. Therefore it is very often illustrated by the “PVT diagram” or phase behavior envelope. Understanding phase behavior is critical to the hydrocarbon recovery mechanism and production prediction. Certain concepts, demonstrated in Figure 1.1, associated with phase envelopes are worth introducing before we discuss different types of natural gas behaviors.

- ❖ **Bubble Point Curve:** the curve that separates the pure liquid (oil) phase from the two-phase (natural gas and oil) region. This means that at a given temperature, when pressure decreases and below the bubble point curve, gas will be emitted from the liquid phase to the two-phase region.
- ❖ **Dew Point Curve:** the curve that separates the pure gas phase from the two-phase region. It is the connected points of pressure and temperature at which the first liquid droplet is formed out of the gas phase.
- ❖ **Critical Point:** the point on the phase envelope where the bubble point curve meets the dew point curve. At that given pressure and temperature, gas properties are identical to liquid properties. The pressure and temperature at the critical point are called critical pressure and temperature, respectively.
- ❖ **Cricondentherm:** the highest temperature at which liquid and vapor can coexist. That means the mixture will be gas irrespective of pressure when the temperature is larger than cricondentherm.

- ❖ **Cricondenbar:** the highest pressure at which a liquid and vapor can coexist.

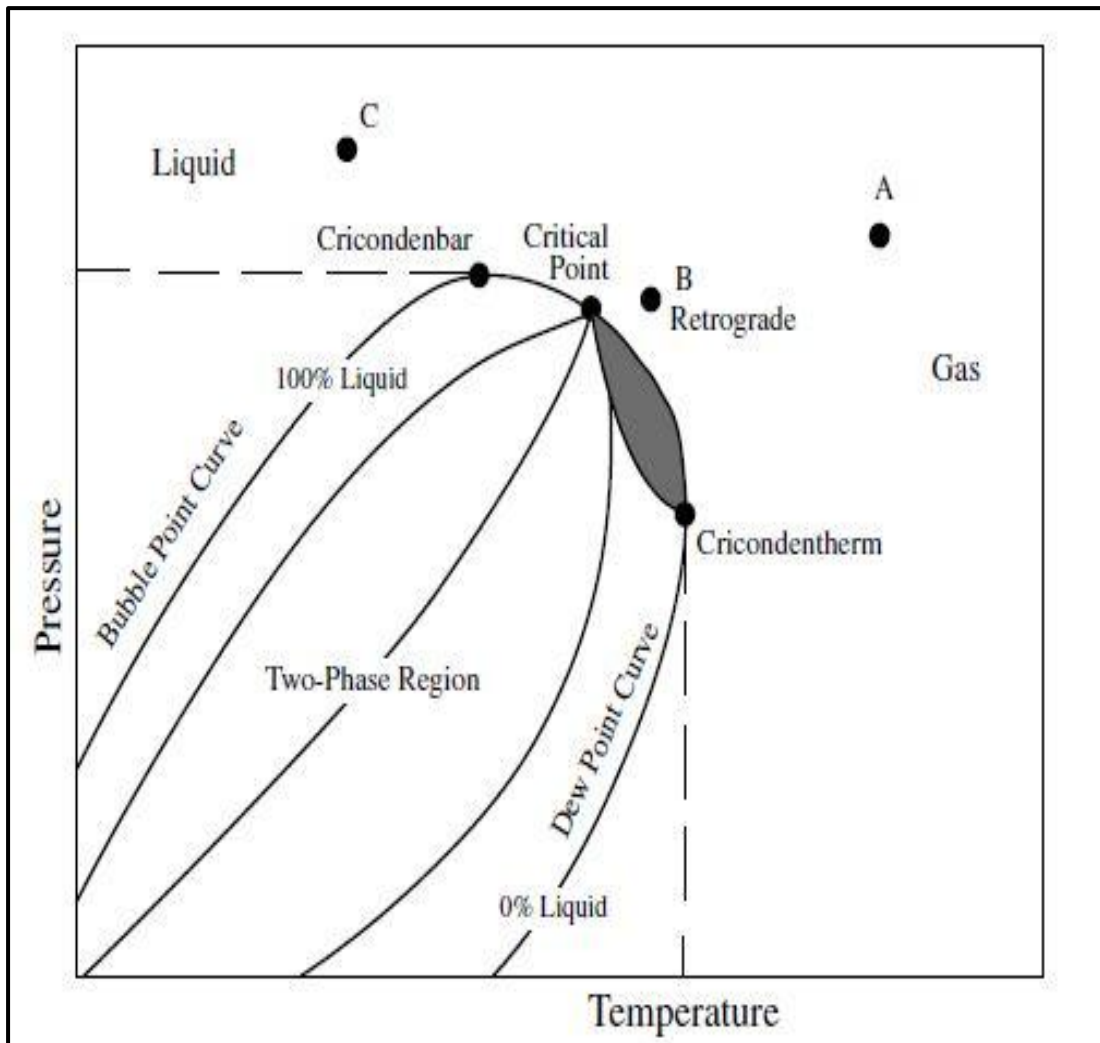


Figure 1.1: Phase diagram

Clearly, the natural gas phase envelope can be very different depending on its source.

In general, reservoirs are conveniently classified on the basis of the location of the point representing the initial reservoir pressure p_i and temperature T with respect to the pressure-temperature diagram of the reservoir fluid. Accordingly, reservoirs can be classified into basically two types. These are:

- ❖ **Oil reservoirs:** If the reservoir temperature T is less than the critical temperature T_c of the reservoir fluid, the reservoir is classified as an oil reservoir.

- ❖ **Gas reservoirs:** If the reservoir temperature is greater than the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir.

2.2.2 Dry- and Wet-Gas Phase Behaviors

Dry gas is in the gaseous phase under reservoir conditions, as marked by **point A** in Figure 1.1. It contains primarily methane with small amounts of ethane, propane, and butane, with little or no heavier compounds. When it is produced to the surface, it is maintained in the gaseous phase with surface temperature falling outside the two-phase envelope. Therefore it will not form any liquids, which are at times referred to as NGL (natural gas liquids).

Wet gas, on the other hand, will have liquid dropped out once it reaches the surface, which means that the surface conditions of pressure and temperature will fall inside the two-phase region.

2.2.3 Retrograde-Condensate-Gas Phase Behavior

Retrograde condensate systems and reservoirs are a unique phenomenon that appears only among hydrocarbon mixtures. No other mixtures of gases exhibit such behavior. As pressure decreases from **point B** to the two-phase shaded area in Figure 1.1, the amount of liquid in the reservoir increases. As pressure decreases further, liquid starts to revaporize. Between the dew point and the point where liquid revaporizes is the region (shaded area in Figure 1.1) of retrograde condensation. Many natural gas reservoirs behave in this manner. During production from such reservoirs, the pressure gradient formed between the reservoir pressure and the flowing bottomhole pressure may result in liquid condensation and form a condensate bank around the wellbore, reduce gas relative permeability and remain unrecoverable. Sometimes it could seize production.

One way to prevent the formation of condensate is to maintain the flowing well bottomhole pressure above the dew point pressure. This is often not satisfactory because the drawdown (reservoir pressure minus flowing bottomhole pressure) may not be sufficient enough for the economic production rate. An alternative technique is to allow the formation of condensate, but occasionally to inject methane gas into the production well. The gas dissolves and sweeps the liquid condensate into the reservoir. The well is then put back in

production. This approach is repeated several times in the life of the well. It is known as gas cycling. Another way is to inject both nitrogen and methane, which develops a miscible displacement process and results in high condensate recoveries.

Removing the bank of condensate from the near-wellbore region is still a challenge for the oil and gas industry. Understanding the near-wellbore gas-condensate flow is thus very important to optimize production of gas-condensate reservoirs.

2.2.4 Associated Gas Phase Behavior

Under reservoir conditions, gas is often dissolved in the oil phase as associated gas. As it is produced to the surface under lower pressure and temperature, gas will come out from the oil phase. An oil reservoir whose pressure is above the bubble point (**point C** in Figure 1.1) is usually referred to as under-saturated. If the pressure is inside the two-phase envelope it is called a saturated, or two-phase, reservoir and may form a gas-cap on top of the oil zone.