Gas Engineering

Midterm Model Answer

2016-2017

Question (I):

1. **What is meant by the followings?**
   i. **Gross heating value**

It is the higher heating value of a fuel. It is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C, which takes into account the latent heat of vaporization of water in the combustion products (All the water formed is a liquid).

ii. **Gas formation volume factor**

The gas formation volume factor is used to relate the volume of gas, as measured at reservoir conditions, to the volume of the gas as measured at standard conditions, i.e., 60°F and 14.7 psia. This gas property is then defined as the actual volume occupied by a certain amount of gas at a specified pressure and temperature, divided by the volume occupied by the same amount of gas at standard conditions. In an equation form, the relationship is expressed as

$$B_g = \frac{V_{P,T}}{V_{sc}}$$

iii. **Gas cycling**

In Many natural gas reservoirs, during production, 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.
An economic technique to solve the problem is to occasionally 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.

iv. **Cricondenbar and cricondentherm**

The highest pressure at which a liquid and vapor can coexist is called cricondenbar and the highest temperature at which liquid and vapor can coexist is called cricondentherm.

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2. **A sour natural gas has a specific gravity of 0.72. The compositional analysis of the gas shows that it contains 5 percent CO_2 and 10 percent H_2S.**
   i. ***Calculate*** **the density of the gas at 3500 psia and 160°F.**
   ii. **If gas well is producing at a rate of 15,000 ft^3/day, calculate the gas flow rate in scf/day.**

Solution

Step 1. Calculate the uncorrected pseudo-critical properties of the gas:

$$T_{pc} = 168 + 325(0.72) - 12.5(0.72)^2 = 395.52\ °R$$

$$P_{pc} = 677 + 15.0(0.72) - 37.5(0.72)^2 = 668.36\ psia$$

Step 2. Calculate the pseudo-critical temperature adjustment factor from:

$$\varepsilon = 120[0.15^{0.9} - 0.15^{1.6}] + 15(0.1^{0.5} - 0.1^{4.0}) = 20.735$$

Step 3. Calculate the corrected pseudo-critical temperature by applying:

$$T'_{pc} = 395.52 - 20.735 = 374.785$$

Step 4. Adjust the pseudo-critical pressure

$$P'_{pc} = \frac{P_{pc} T'_{pc}}{T_{pc} + B(1-B)\varepsilon}$$

$$P'_{pc} = \frac{668.36 \times 374.785}{395.52 + 0.1(1-0.1)(20.735)} = 630.347$$

Step 5. Calculate P_{pr} and T_{pr}:

$$P_{pr} = \frac{3500}{630.347} = 9.71$$

$$T_{pr} = \frac{160 + 460}{374.785} = 1.654$$

Step 6. Determine the z-factor from given Figure:

$$z = 0.87$$

Step 7. Calculate the apparent molecular weight of the gas:

$$Ma = (28.96)(0.72) = 20.85$$

Step 8. Solve for gas density:

$$\rho_g = \frac{(3500)(20.85)}{(0.87)(10.73)(620)} = 12.61\ lb/ft^3$$

$$E_g = 35.37 \frac{P}{zT}\ , scf/ft^3$$

$$E_g = 35.37 \frac{3500}{0.87 \times 620} = 229.51\ \ scf/ft^3$$

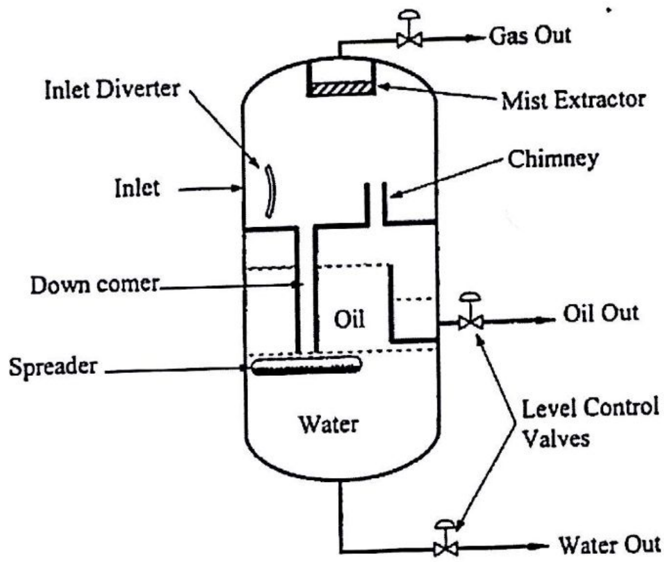
$$gas\ flow\ rate = E_g \times production\ rate = 229.51 \times 15000 = 3.443\ MMscf/day$$

Question (II)

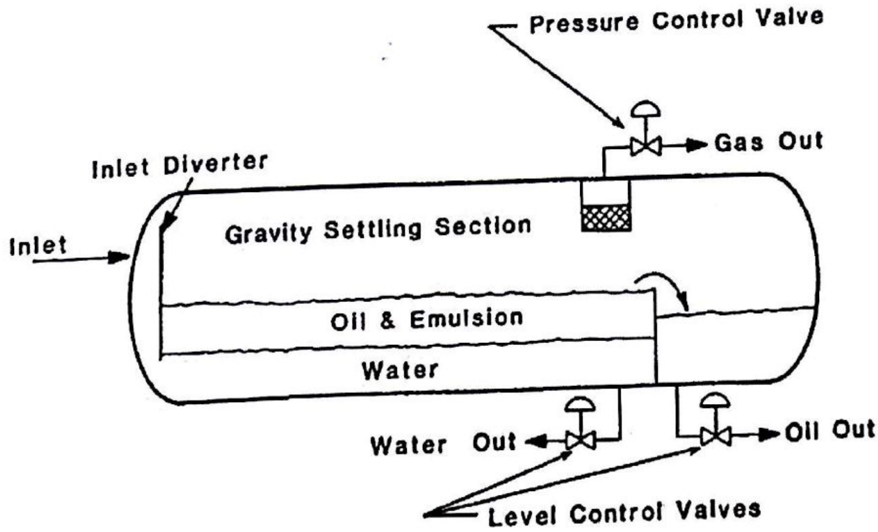
1. **Discuss the different methods used to prevent the formation of gas hydrates?**

- By dehydration of gas stream, so that water vapor will not condense into free water (if no free water, hydrates cannot form).
- Keep the temperature above hydrate formation temperature.
- Design process to melt hydrates (e.g. expansion vessel may be equipped with a heating coil to melt hydrates).
- A hydrate-preventive liquid (such as glycol) may be injected into the stream.

2. **Compare between vertical and horizontal three phase separators?**



Vertical three phase separator



Horizontal three phase separator

The three phase separation vessel commonly contains four major sections as listed below:

a. The primary separation section used to separate the main portion of free liquid in the inlet stream

b. The secondary or gravity section designed to utilize the force of gravity to enhance separation of entrained droplets.

c. The coalescing section utilizes a coalescer or mist extractor. Our normal application is using a knitted wire mesh pad on top of vessel.

d. The sump or liquid collection section acts as receiver for all liquid removed from gas in the primary, secondary, and coalescing section.

Horizontal vessels are most economical for normal oil-water separation, particularly when there might be problems with emulsions, foam, or high gas-liquid ratios. Vertical vessels work most effectively in low gas-oil ratio (GOR) applications and where solids production is anticipated.

VERTICAL SEPARATOR	HORIZONTAL SEPARATOR
Advantages: 1. Easier to clean 2. Saves space 3. Provides better surge control 4. Liquid level control is not critical 5. Less tendency for re-evaporation of liquid into the gas phase due to the relatively greater vertical distance between liquid level and gas outlet	**Advantages:** 1.Can handle much higher gas-oil ratio wellstreams because the design permits much higher gas velocities 2.Cheaper than the vertical separator 3.Easier and cheaper to ship and assemble 4.Requires less piping for field connections 5.Reduces turbulence and reduces foaming (thus, it can handle foaming crude) 6.Several separators may be stacked, minimizing space requirements
Disadvantages: 1. It takes a longer diameter separator for a given gas capacity as compared to horizontal separator 2. More expensive to fabricate 3. Difficult and more expensive to ship (transport)	**Disadvantages:** 1.Greater space requirements generally 2.Liquid level control more critical 3.Surge space is somewhat limited 4.Much harder to clean

Mention the different parameters that can affect the oil and gas separator efficiency?

(1) Physical and chemical characteristics of the crude,

(2) Operating pressure,

(3) Operating temperature,

(4) Rate of throughput,

(5) Size and configuration of the separator.

3. **Write short notes on the followings**

   i. **Hydraulic fracture**

Hydraulic Fracturing is the process of transmitting pressure by fluid or gas to create cracks or to open existing cracks in hydrocarbon bearing rocks underground.

The purpose of hydraulic fracturing an oil or gas reservoir is to enable the oil or gas to flow more easily from the formation to the wellbore.

In brief, the technique involves pumping a water-rich fluid into a borehole until the fluid pressure at depth causes the rock to fracture. The pumped fluid contains small particles known as proppant (often quartz-rich sand) which serve to prop open the fractures. After the fracking job,. the pressure in the well is dropped and the water containing released natural gas flows back to the well head at the surface.

The boreholes themselves are often deviated away from the vertical, into sub horizontal orientations, to ensure better and more efficient coverage of the targeted shale gas reservoir. The fracking fluid also contains small amounts (typically < 2% in total by volume) of chemical additives such as acid to help initiate fractures, corrosion and scale inhibitors to protect the borehole lining and gelling agents to alter the fluid viscosity.

   ii. **Coal bed methane**

It is the methane gas that is found adsorbed on the internal surfaces of the coal or absorbed within the coal's molecular structure. This gas can be produced in significant quantities from wells drilled into the coal seam by lowering the reservoir pressure.

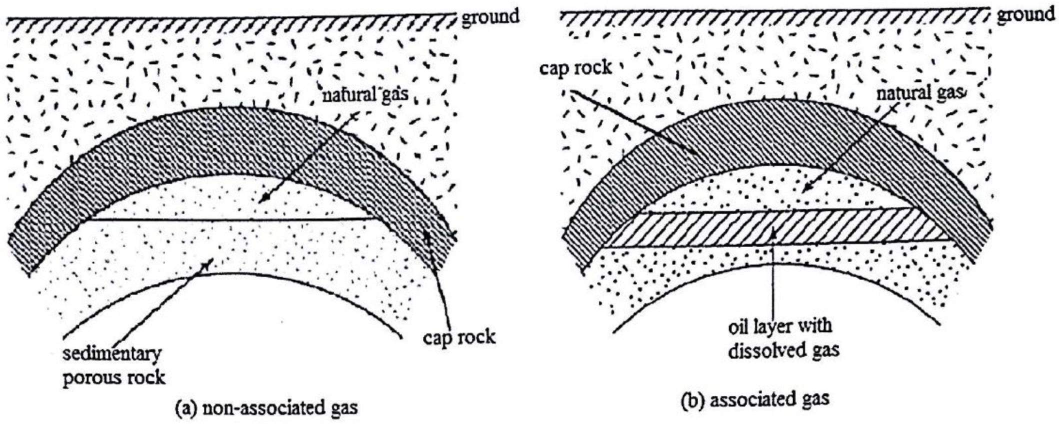
As is the case with conventional natural gas, the composition of the CBM produced varies widely. In addition to methane, these gases may contain as much as 20% ethane and heavier hydrocarbons, as well as substantial levels of carbon dioxide. However, a typical CBM analysis would reveal water saturation, up to 10% carbon dioxide, up to 1% nitrogen, no or very small amounts of ethane and heavier hydrocarbons, and a balance of methane. Because water is normally present in the reservoir, it is produced in significant amounts along with the CBM, and this produced water can pose a significant problem because it may contain large quantities of dissolved solids that make it unfit for many uses.

   iii. **Conventional natural gas sources**

The presence of gas in a mixture of hydrocarbons depends on their phase behavior, which in turn, depends greatly on the pressure and temperature of the mixture. There are exceptions that at depths of 3,000 ft or less are likely to contain heavy oil with virtually no gas. Oil becomes lighter as the depth increases, which means that gas coexists with oil.

Around 10,000 to 12,000 ft depth are some of the most prolific oil reservoirs in the world and almost all of them contain oil associated with substantial quantities of gas (***associated gas***), which, when separated from oil at the surface.

At greater depths, e.g., 17,000 ft and certainly over 20,000 ft, reservoirs contain almost exclusively natural gas (***non-associated gas***).



Conventional natural gas resources

Non-associated Gas

These are reservoirs that contain almost entirely natural gas at reservoir conditions. They are generally found at greater depth as previously mentioned. If the fluid at the surface still remains gas (almost methane only), then it is called "dry gas." If the surface pressures cause some liquid hydrocarbons to separate, it is called a "wet gas" reservoir. Wet gas contains considerable amounts of the higher molecular weight hydrocarbons.

Associated Gas

Almost all oil reservoirs except those classified as extra heavy or tars will produce some natural gas at the surface. Gas can be in the form of a gas-cap on top of the oil zone, or it can be dissolved in the oil. As depth increases, more gas is present.