Artificial Lift

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Lecture-07 Fluid Properties and Phase Diagram Part-1

Today, I will discuss the fluid properties of oil and gas. When you obtain oil and gas from the reservoir, the reservoir fluid properties will change due to variations in temperature and pressure. I will explain the physics behind this during this lecture. So, first, let's assume you have a Coca-Cola bottle or Pepsi, whatever you prefer. When you open the bottle, some gas escapes suddenly. If you shake it properly, the gas will splash around.

So, what happens inside the Coca-Cola bottle? Initially, you inject a lot of carbon dioxide at high pressure. When you mix a high amount of carbon dioxide with water under pressure, you have a single-phase fluid. But when you remove the cap, what occurs? You release the pressure at that point, and the carbon dioxide moves out of the bottle. What's the reason for this? The reason is that free gas behaves like birds—you can't confine them.

They want to fly and dance in the air, within the atmosphere, in the sky, among the clouds. Air particles behave similarly. Instead of remaining within the liquid volume, they engage in Brownian motion, and if you release the pressure, they attempt to escape and dance within the atmosphere. This is the primary tendency of air or dry gas particles. What happens if you force them, just like trying to capture a bird? The bird won't be content.

And if you open the door of the cage, it will go away and fly in the sky. Similarly, in our case, air particles engage in Brownian motion when pressure is released. So, when you pressurize carbon dioxide into a Coke bottle, it dissolves, but the gas escapes once the pressure is released.

Let's consider this as our reservoir, and the pressure is, say, 500 bar—very high pressure. There will be several wellbores, including high-pressure wellbores and low-pressure wellbores.

The pressure in the high-pressure, high-temperature wellbore may be around 400 bar or more, and the temperature could reach 150 degrees Celsius or higher. In such cases, at very high temperatures and pressures, the liquid and gas will compress, creating single-phase fluid many times, and at times, it will create two-phase fluid.

Let's take a certain amount of fluid from here, perhaps at 500 bar and 100 degrees Celsius (or 212 degrees Fahrenheit). You place this sample in a closed vessel that is properly sealed to maintain temperature and pressure. Then, you take that vessel out and slowly release the pressure.

What will happen if you slowly release the pressure, like removing the cap from a Coca-Cola bottle? Initially, gas will escape from the liquid.

Once the gas has escaped, you will be left with gas-free liquid, but the temperature may still be high. You then reduce the temperature to maintain normal atmospheric conditions. In the oil and gas industry, we refer to standard temperature, defined as 14.7 psi (pounds per square inch) pressure and 60 degrees Fahrenheit. We do not use centigrade or Newton meter per meter square (Pascal). Instead, we use 14.7 psi, commonly used in oil and gas industry field applications, along with Fahrenheit.

In standard conditions, we refer to 14.7 psi and 60 degrees Fahrenheit. So, the reservoir fluid you obtain is like opening a Coca-Cola bottle and changing the pressure and temperature. During this process, gas will escape. You can measure how much gas has been released. Since the reservoir pressure was initially high, gas and oil were compressed. Therefore, the compressibility on the surface changes and the difference in the gas-to-oil ratio on the surface affects the fluid's viscosity.

So, measuring how much gas or free gas comes out from the liquid is essential. If you don't measure it, you'll face issues designing separation and artificial lifting systems.

When your reservoir experiences pressure changes over time, for example, it's initially at 500 bar and 100 degrees Celsius, but after two years, the pressure drops to 100 bar, several things occur. The fluid that was once a liquid or gas may become a two-phase flow due to the pressure change. When a two-phase flow occurs, viscosity, density, and other fluid properties change.

Due to these changes, your artificial lifting system, whatever mechanical arrangement you have, may no longer function effectively. Therefore, it's crucial to understand the fluid properties in the reservoir, at the surface, and the pressure changes that occur during the fluid's journey from the reservoir's depth to the wellhead.

Pressure changes happen because of hydrostatic pressure. If you consider h (height), rho (density), and g (gravity), you'll see that pressure is related to height, so as the fluid moves through varying heights in the wellbore, pressure changes accordingly.

rho. g. Now, your density is changing. I mentioned that g doesn't change because it's a universal constant. In SI units, it's 9.81 meters per second squared; in FPS units, it's 32 pound-force per meter per second.

However, h is changing, and when h changes, rho changes. When rho changes, hydrostatic pressure changes, and changes in hydrostatic pressure, in turn, lead to viscosity and density changes.

This means that the entire wellbore system, including the mechanical components, must be modified based on the changes in reservoir pressure. You also need to understand fluid properties. Why is this important? Designing and selecting an artificial lift system becomes challenging if you don't know how much gas the fluid can dissolve or release when pressure changes.

In this lecture, I'll explain various fluid properties within the wellbore and how the same fluid behaves when brought to the surface. Several formulas and correlations exist, many empirical and derived from reservoir data. Researchers collect samples and take them to PVT (pressure, volume, and temperature) laboratories worldwide. These labs analyze the fluid's composition, density, viscosity, other parameters,

The data is then used to create charts and tables provided to engineers involved in relevant work. For example, artificial lift experts need to know the fluid properties and how it behaves when it returns to the surface, and they rely on PVT analysis.

In the last lecture, we discussed the phase diagram. Whenever we talk about whether gas will be absorbed, dissolved, or released, it's based on the PVT analysis, which involves the phase diagram.

The phase diagram is as follows, and I've explained it before. This is the critical point, the bubble point line, and the dew point line. We have pressure on one axis and temperature on the other. Let's assume that your reservoir pressure and temperature are initially here. As you slowly reduce the pressure due to fluid production through the wellbore, your pressure changes, and at the wellhead, the conditions are here, in the two-phase region.

So, at the wellhead, you have a two-phase region. In this case, what will happen is that the entire reservoir is single-phase, but near the wellbore or wellhead, it becomes two-phase. Due to this two-phase region, the fluid properties have already changed. The system dynamics will change, and mechanical designs must be adjusted to accommodate this two-phase behavior. If you don't understand this phase diagram and are producing from the wellbore, you might notice lots of gas on the surface that you cannot handle. This can lead to problems, especially with artificial lifting systems.

For example, let's assume you're assuming there's a single-phase fluid at 100 bars of pressure, and because of this phase change, your pumping system (let's say you're using an ESP, Electric Submersible Pump) doesn't handle gas well. Now, due to the creation of this two-phase situation, you have gas because of the lowered pressure, and the gas interferes with the entire pumping system. This interference can lead to vibrations and cavitation, ultimately causing the pump to fail.

It would help if you understood the phase diagram before selecting any artificial lift method. This phase diagram is provided by reservoir engineers who perform PVT (Pressure-Volume-Temperature) analysis and other mathematical analyses. They create charts that help you choose the appropriate artificial lift method based on their findings.

Now, let's move on. When discussing fluid properties, several factors need consideration. Firstly, there's the Solution Gas-Oil Ratio (GOR), represented as R_S, which stands for the gas-oil ratio. This ratio indicates the amount of gas to oil. R_S is calculated as V_{gas} divided by V_{oil}. Imagine you take a certain volume of oil and gas mixture in a closed vessel. When this mixture is subjected to reservoir conditions with higher temperatures and pressure in the wellbore, the oil will absorb a certain amount of extra gas. This excess gas volume is measured in standard cubic feet (SCF) and stock tank barrels (STB). SCF stands for standard cubic feet, which refers to surface conditions with 14.7 psi and 60 degrees Fahrenheit temperature, while STB stands for stock tank barrel.

$$R_s = \frac{V_{gas}}{V_{oil}}$$

$$R_s = \gamma_g \left[\frac{p}{18} \frac{10^{0.0125(^{\circ}API)}}{10^{0.00091t}} \right]^{1.2048}$$

A "stock tank barrel" refers to surface or standard conditions, specifically 14.7 psi and 60 degrees Fahrenheit. These conditions can change with alterations in temperature and pressure. Therefore, temperature and pressure must be indicated when specifying parameters like the solution gas ratio. Without specific temperature and pressure values, describing gas density becomes meaningless.

Unit; lbm/ft^3

$$^{\circ}API = \frac{141.5}{\gamma_o} - 131.5$$

$$\gamma_o = \frac{\rho_{o,st}}{\rho_w}$$

Ahmed (1989) gave the correlation

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{0.972 + 0.000147 \left[R_s \sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25t \right]^{1.175}},$$

On the other hand, water density is typically not specified because it is often assumed to be under atmospheric conditions. However, assumptions can vary when discussing oil and gas, so it's crucial to specify temperature and pressure to ensure clarity.

It is moving on to the definition of R_S (Solution Gas-Oil Ratio). R_S is a fundamental term used in various calculations derived from PVT (Pressure-Volume-Temperature) analysis. Another term to consider is "gamma g," which represents the specific gravity of gas. The formula for RS involves psi pressure and API gravity. API stands for the American Petroleum Institute, an organization that standardizes various aspects of the industry. API develops norms and regulations for designing artificial lift systems, materials used in pipelines, criteria for dealing with corrosive fluids, and more.

The American Petroleum Institute (API) produces numerous documents, theories, and formulas to ensure the safe and standardized use of these formulas in the industry. API is crucial in setting standards and guidelines for various oil and gas industry aspects. Regarding viscosity and gravity, API has introduced the concept of "degree API," which is specific to the oil and gas industry and differs from the density and viscosity definitions found in standard physics books typically used in 7th and 8th-grade physics classes.

The term API will be used frequently in this context because the American Petroleum Institute has established numerous standards and guidelines widely accepted in the industry. When adhering to API standards, you don't need to specify all parameters individually, as they are already established. However, if you choose not to follow API standards, you must provide a rationale for selecting parameters, including diameter, materials, etc.

API gravity (API) is defined in relation to temperature, typically measured in degrees Fahrenheit in the oil industry, as opposed to degrees Celsius (centigrade). The Rankine temperature is sometimes used, with 1 Rankine equal to 460 degrees Fahrenheit.

Regarding density, while the standard definition is mass divided by volume (as learned in school), in the oil industry, density becomes more complex due to the presence of various mixed components, such as different carbon chains (C1, C2, C3), short-chain hydrocarbons, long-chain hydrocarbons, temperature dependencies, and pressure dependencies. Density in the oil industry is typically expressed in pounds mass per cubic feet (lbm per cubic foot), and API gravity is calculated using the formula 141.5 divided by (γ_o -131).

The term " γ_o " represents the gravity of oil and is defined as the density of oil at standard conditions, denoted as "rho w" for water density at standard conditions. Standard conditions are typically defined as 14.7 psi and 60 degrees Fahrenheit. Water density is usually considered a fixed value, approximately 1000 kg per cubic meter. Various density correlations are used in the industry, but one commonly used correlation is known as the Ahmed correlation, which was introduced in 1989. This correlation relates the density of oil (ρ_o) to the oil gravity (γ_o), the solution gas ratio (R_S), the gas gravity (γ_g), and the temperature (T), measured in degrees Fahrenheit.

$$B_o = \frac{V_{res}}{V_{st}}$$

$$B_o = 0.9759 + 0.00012\left[R_s\sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25t\right]^{1.2}$$

The correlation equations can be quite lengthy and involve numerous constant terms. I often provide these correlations during exams or problem-solving sessions, but students must comprehend and apply them correctly. Understanding the units is crucial, as unit conversions may be necessary when solving problems or working with equations.

If you do not make these changes, the entire result will be incorrect, and you might receive poor marks, or I may not award marks for the wrong answer because you didn't make the necessary adjustments. I intended to evaluate whether you could identify the units involved. If you fail to remember the units and attempt to solve the problem, your approach may be sound, but my goal was to assess your ability to recognize the units. This is why I am emphasizing units and definitions so that students become familiar with them and understand how to convert between units and revert them.

Let me share a story. I worked in the United Kingdom from 2008 to 2010 in the oil and gas industry, receiving data from companies like Chevron. They provided data in field units, but we typically studied using SI units in engineering in India. I created an Excel sheet; whenever I received data, I converted it into SI units, conducted all my calculations and designs, and then reconverted them back into field units when delivering the final results to the company. Why did I do this? Because the company personnel were more familiar with field units than SI units. So, I conducted all my calculations in SI units but provided the final data in field units. This made it easier for them to understand and use the results.

That's why it's essential to know how to convert and revert units and to identify which units require conversion and which do not. For instance, if I provide a temperature in Celsius, you should be able to convert it into Fahrenheit without any issues. I hope this clarifies things.

Now, let's discuss the formation volume factor. When we talk about the formation volume factor, the term "volume" comes into play, indicating a volume-related aspect. It refers to fluid volume within a reservoir and how it changes under standard conditions. The reservoir volume, sometimes referred to as Rb or reservoir barrel is compared to the volume under standard conditions, known as stock tank barrel (STB).

Here, I should clarify the term "barrel." I need to explain it. Sometimes, you may encounter the abbreviation "BBL" in documents, which stands for "blue barrel" or simply "barrel." Why "blue barrel"? In the 1860s, during the early development of the US oil and gas industry, barrels were used to transport oil. However, various industries were also using similar barrels, typically made of wood. These barrels were used for storing and transporting substances like alcohol. In the case of the oil industry, they decided on a 42-gallon barrel as their standard. This deviation from the 40-gallon barrels used in other industries was due to factors such as evaporation and leakage. Therefore, in the standardized format, one barrel in the US became equivalent to 42 gallons.

On the other hand, other industries stuck with 40 gallons per barrel. Now, let's delve into the formation volume factor. When discussing the formation volume factor, we deal with a volume-related aspect. It pertains to the fluid volume within a reservoir and how that volume changes under standard conditions, which we denote as stock tank barrel (STB), compared to the reservoir volume, sometimes referred to as Rb or reservoir barrel.

At this point, I'd like to clarify the term "barrel." I believe it needs some explanation. You might encounter the abbreviation "BBL" in documents, standing for "blue barrel" or simply "barrel." But why "blue barrel"? In the 1860s, barrels were used for transporting oil during the early development of the US oil and gas industry. However, these barrels were similar to those used in various other industries, typically wood-made. They were used for storing and transporting substances like alcohol. A standard barrel contained 42 gallons in the oil industry, deviating from the 40-gallon barrels used in other sectors. This adjustment was made to account for factors such as evaporation and leakage. Consequently, one barrel in the US became equivalent to 42 gallons.

In contrast, other industries continued to use 40 gallons per barrel. So, 1 BBL equated to 42 gallons. As for the "blue barrel" reference, it's worth noting that these wooden containers were often painted blue. The term "blue" holds no particular significance, but people in the industry commonly use "BBL."

This distinction is crucial, especially when you come across fluctuating news about oil prices. Such reports will often mention the price per barrel, and production figures are typically measured in millions of barrels, making the barrel a standard unit in the oil and gas industry. Remembering that this unit is not part of the SI system is essential. However, it is widely understood by people in India and worldwide who are involved in the oil industry. When communicating with industry professionals, mentioning "cubic meter," "cubic meter per second," or "meter cube" could lead to confusion, so using "barrel" is preferable.

Returning to the formation volume factor, it involves taking a specific quantity of oil and measuring its volume at the surface, comparing it to its volume in the reservoir. This comparison reveals how the volume changes, which we call the formation volume factor. You might wonder how this factor is affected by the phase diagram. You can think of the phase diagram like this:

If you have a certain amount of oil in this region and alter the pressure (P_t), you'll transition into a two-phase or perhaps a single-phase zone. When you reduce the pressure to a significant extent, it can become completely single-phase gas or dry gas. By "dry gas," I mean there's no... here; one term to clarify is "dry" and "wet." Typically, "wet" is associated with water. However, "wet" signifies wet with oil when discussing oil and gas. You take a certain amount of reservoir oil, increase the temperature, and reduce the pressure until it becomes entirely gas after a certain point. But if you then increase the pressure and reduce the temperature, some liquid, which in this context means oil, will reappear. This liquid component is referred to as wet gas, where the "liquid" might not necessarily be water but could be another hydrocarbon.

Now, regarding the formation volume factor (F_{vf}), it's associated with pressure (psi). We will use psi here rather than other units like bars or Newtons per square meter since oil field personnel commonly use psi in their field units. Consider the scenario where you start at zero pressure or, let's say, one atmosphere of pressure, and then you gradually increase the pressure to a very high level, like 20,000 Psi. The relationship appears like this, with P_b (bubble point). Initially, the pressure gradually decreases as you decrease the pressure while maintaining a certain amount of the oil and gas mixture under reservoir conditions. During this process, you have a single-phase liquid. As you continue to decrease the pressure, at a certain point, the gas trapped within the liquid will begin to escape, creating bubbles.

So that is the bubble point pressure, alright? The liquid will start bubbling, and then the formation volume factor will initially increase as pressure is reduced, causing the volume to increase. However, more bubbles will emerge as gas is released from the liquid when the pressure is reached and then reduced further. When you forcibly introduce gas into the liquid, it will escape, fly, run, and dance. Consequently, the formation volume factor will decrease, and the volume will continue to decrease until it reaches nearly 1. The formation volume factor of a dead well is 1 at zero pressure.

The relationship between the formation volume factor and the solution gas-oil ratio is depicted as follows: F_{vf} (B_o) and R_s (solution gas-oil ratio). The figure illustrating this relationship will appear like this.