Artificial Lift

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Lecture-06 Reservoir Fluid

When you opt for a wider pipe, let's say D (diameter) increases from 2 inches to 5 inches, or typically from 3 and 8 inches to 5 and a half inches in diameter. The piping diameter, tubing diameter, or casing diameter is usually specified by API (American Petroleum Institute) in inches, not centimeters or millimeters. They often use fractional measurements, such as 2 and 3/8 inches or 2 and 7/8 inches, to designate tubing sizes.

API specifications typically refer to the outer diameter. When calculating fluid flow inside the tubing, you must consider this diameter. Let's consider changing the piping diameter from 2 to 5 inches, for example. What will happen is that the fluid flow rate will decrease while maintaining the same pressure and flow rate. Consequently, the velocity will decrease despite maintaining the flow rate.

When the velocity decreases, small sand particles, if present, may not be carried by the fluid. Small sand particles might still enter the flow despite having a sand control system. Due to the reduced velocity, the sand will not move with the fluid, causing it to accumulate near the bottom, especially in the perforation zone. Perforations are made to allow oil and gas into the wellbore. The sand will gradually settle if you do not maintain the fluid velocity near the perforations. When the fluid settles after a certain period, we can conclude that everything is blocked near the perforation area.

So, when your fluid is not entering, you encounter another difficulty. What is this difficulty? If sand accumulates, you must either remove the tubing or perform a workover operation. This operation is known as a workover. If production is affected, you must reduce the fluid flow, and if production stops, you have to halt fluid flow and then rework the wellbore before restarting production. In such cases, the standard procedure is to remove the sand from the wellbore and handle it at the surface, eliminating the need for in-wellbore work.

Why is workover considered expensive? Well, some wellbores are located in remote areas. In remote areas, access is difficult, often requiring expensive transportation methods like helicopters and construction efforts. Hence, minimizing the need for wellbore workovers or interventions is crucial. Creating a problem-free wellbore during the completion stage is essential.

The artificial lifting system should operate smoothly for an extended period, ensuring cost-effectiveness. Therefore, using very narrow or wide pipes is not advisable. Instead, it's important to select an optimal pipe size.

So, completion engineers, when installing piping, and surface separation system engineers, when production engineers set up pipes, should aim for an optimal piping size. However, they may encounter difficulties such as excessive pressure drop, sand settling, or other issues related to permeability and porosity. These terms are fundamental in the oil and gas industry. Permeability and porosity are basic terms used by all oil industry professionals. Let's understand the concepts. First, draw one figure like this and another figure like this, representing two different sections.

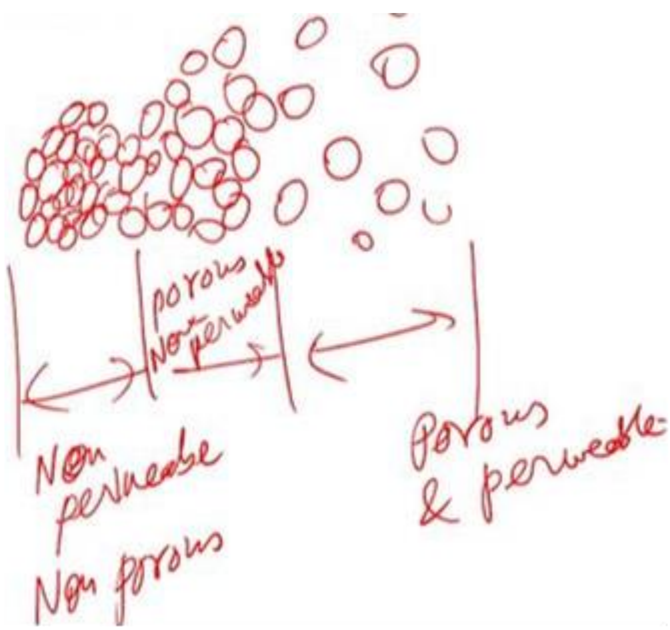

Fig.1. Permiability and porosity.

Now, consider these three sections: 1, 2, and 3. In the first part, it's non-permeable and non-porous. The second part is porous but non-permeable, while the third is porous and permeable. What's the difference? Porosity refers to the presence of voids or empty spaces within a material. These voids can contain gas, water, or oil. The critical factor is whether these voids are connected. If the voids are not connected, it becomes challenging to extract fluids during drilling. However, when you have interconnected voids, fluids like oil, gas, and water can flow through them, even if there are many voids.

So, these are connected. But if you look at the second one, there are pockets that are not connected. Porosity means you have voids that can contain oil and gas but are not connected. Permeable, however, means that voids exist and are interconnected. When you have a permeable reservoir, it becomes much easier to extract oil and gas. However, if you have a porous but non-permeable reservoir, you may need specific mechanisms like hydraulic fracturing to connect the pores and improve production. For instance, if you have a non-porous, non-permeable area in the oil reservoir, no useful pores are present. In this case, you might need to drill further to find a porous area or employ hydraulic or acid fracturing methods to connect the pores. When the pores are connected, production increases.

If you already have a permeable and porous reservoir, you're in luck, as it simplifies the extraction process. It would help if you understood the definition of permeability, expressed as,

$$q = \frac{kA\Delta p}{\mu l}$$

$$k = \frac{q\mu l}{\Delta p . A}$$

Here, K represents permeability, q stands for discharge rate (with units of volume per time), A is the area (in square feet), μ denotes viscosity (usually in Cp), ΔP represents pressure drop, and L is the length. The unit for K is Darcy, and sometimes milli-Darcy is used, equal to 1/1000 Darcy.

There are different types of reservoir drives, such as water, gas cap, or dissolved gas drives. While there may be other types, there are three main types of reservoir drives: water drive, gas cap drive, and dissolved gas drive. The configuration for a water drive reservoir is as follows: a gas cap above, oil in the middle, and a water layer below. Since water is denser, it naturally occupies the bottom layer, followed by the oil and gas layers. When drilling a well, you typically drill down to the oil layer rather than reaching the gas layer. This setup allows the higher water pressure to push the oil upward, producing oil. This type of reservoir is referred to as a water drive reservoir. In a gas cap drive reservoir, a similar scenario unfolds. Here, you have a layer of gas above the oil layer. When drilling, you reach the oil layer. The high-pressure gas pushes the oil downward, leading to oil extraction.

These are called gas cap drives and water drives, respectively. Next is the dissolved gas drive, similar to this configuration, where you have two phases: liquefied gas and oil. The dissolved gas exerts pressure, so whenever there's a slight pressure drop, a significant amount of gas is released, helping to maintain pressure and drive the fluid up to the surface. This is known as a dissolved gas drive.

In a bottom drive scenario, water can be pressurized from below or from the side, with different aquifer zones providing pressure. Pressurizing from the side is sometimes better because it ensures continuous pressure maintenance. However, in a bottom drive situation, pressure may fluctuate, leading to issues like gas coning, which looks like this.

So, you are getting oil and gas production like this, but there's a concern about water coning. Water coning occurs when water starts forming like this, even though there's oil present. If you don't manage production properly, water can replace oil, which you want to avoid if possible.

When you drill a well, you must understand the different reservoir types. Before going into production, it's crucial to comprehend various fluid properties. These properties include the amount of gas, oil, condensate, and the types of hydrocarbons present. Many parameters need to be known, such as during artificial lift operations, where dissolved gas may be released during centrifugal pumping. This could pose a problem.

Similarly, when separating fluids on the surface, you need to know the wellbore properties to select the separator size and determine the number of separators required for your system. Before moving forward with production, reservoir engineers typically collect fluid samples and create reservoir conditions. They then alter pressure and temperature to observe how parameters change due to these variations.

So, based on this, the completion engineer will decide on different completion mechanisms for surface production. Surface production engineers determine their system operations. PVT, which stands for Pressure-Volume-Temperature, involves taking a specific fluid volume, changing the pressure and temperature, and observing various parameters. This includes density measurements, optical and volumetric analyses, and checking temperature and pressure.

Several stages of analysis are necessary, and other engineers and scientists use the resulting data table. To perform PVT analysis, you start with a certain amount of fluid under reservoir conditions at high pressure and temperature. Then, you slowly release the temperature or pressure to see how the fluid properties change. This helps determine how pressure affects temperature and how much gas or condensate is released.

So, all these parameters will be determined using PVT analysis. Those studying or conducting reservoir analysis obtain data from PVT analysis, including accurate field data. They then conduct further investigations to find molecular weight, molecules, and other fluid properties. This reservoir produces a fluid of sand, water, oil, and gas, making it a four-phase system. While all three phases are present, water and oil are technically considered multi-component fluids because both are liquid. The correct technical term should be 'multi-component fluid.'

In the oil industry, field units and SI units are commonly used. Some companies, like ours, primarily use SI units. When interacting with various service providers, drilling companies, completion companies, and others in the oil field, it's essential to understand both SI units and field units, as you may need to work with different units depending on the context.

In the field, various units are used, such as feet for length, inches for measurement, gallons, and barrels for volume, cubic feet for area, pounds per square inch (psi) for pressure, centipoise (cP) for viscosity, and degrees Fahrenheit for temperature, among others. While I won't provide the conversion data here, I encourage you to remember how to convert between different units, as this knowledge can be valuable.

Additionally, you'll come across terms like 'STB,' which stands for Stock Tank Barrel. In the context of STB, it refers to wellbore fluid processed through the wellhead, choke, and separator before being stored in a tank. This tank holds oil under standard conditions, typically at 14.7 psi and 60 degrees Fahrenheit, representing normal atmospheric pressure and temperature. This state is known as 'stock tank condition.'

We often specify 'stock tank barrel' to indicate dead oil, meaning the oil lacks any volatile components and remains under stock tank conditions. Stock tank condition refers to average temperature and pressure conditions. In this state, when you open a vessel, no volatile components are present in the surroundings. This is what we call a 'stock tank barrel' condition. Another term you might encounter is 'RB,' which stands for Reservoir Barrel. The reservoir barrel represents the conditions prevailing in the reservoir. These conditions often include high temperatures, possibly around 100 degrees Celsius, and high pressures, reaching up to 5000 psi. When you take one barrel of oil under these reservoir conditions, it's referred to as a 'reservoir barrel.'

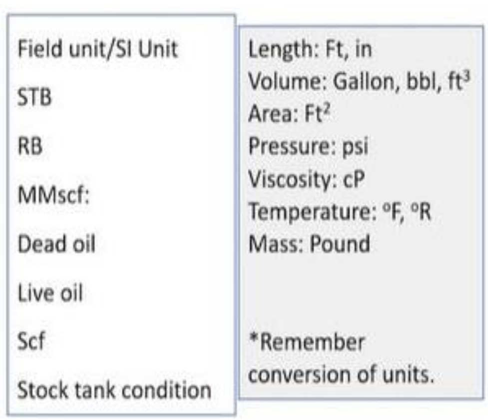

Fig.2. Fluid properties.

Next, we have 'MM SCF.' But before we delve into that, it's important to understand 'SCF,' which stands for Standard Cubic Feet. Standard cubic feet describe gas taken under surface conditions. 'MM' stands for million, so 'MM SCF' refers to million standard cubic feet. It's worth noting that 'dead oil' signifies that the volatile components have dissipated, and the oil is stored in a stock tank. It won't emit a significant amount of hydrocarbon vapor in this state.

Live oil refers to oil in reservoir condition, containing all its volatile and non-volatile components. This is what we call 'live oil.' Additionally, 'SCF stock tanker' is a term we may use intermittently during my teachings on artificial mechanisms. It's essential to remember these terms and familiarize yourself with the units, field units, and specific terms.

Phase diagrams are quite common in the oil industry, and those in the field are usually well-versed. A phase diagram typically consists of temperature (T) and pressure (P) axes, forming a PT diagram. It should look something like this, with key points, including the critical point, which I'll explain how to draw shortly. You'll also see the bubble point, bubble point line, dew point line, and other curves, such as 75 percent, 50 percent, and 25 percent, denoting oil, dry gas, and mixed two-phase regions.

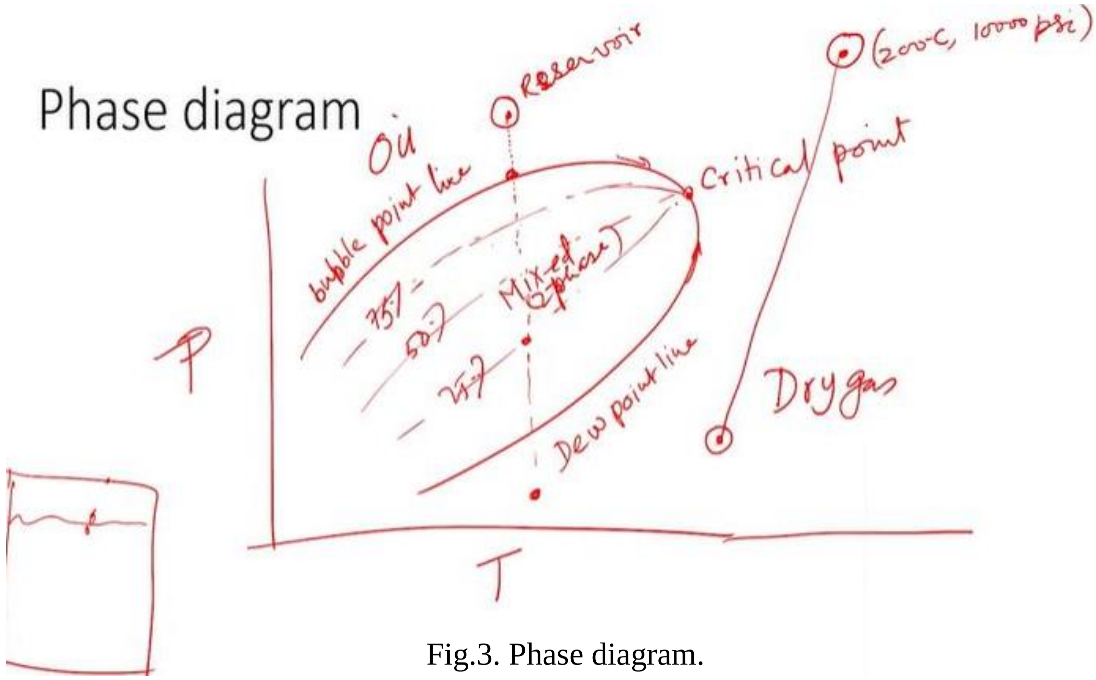

Fig.3. Phase diagram.

Mixed two-phase means it contains both liquid and gas, precisely a mixture of oil and gas. When the temperature and pressure are very high in certain reservoir conditions, you might find yourself at this point. When you produce oil and gas to the surface, the surface conditions differ—let's say 200 degrees Celsius and 10,000 psi pressure. If, for instance, you end up here in the surface conditions, it's still considered a gas well, meaning you're not producing any oil.

However, under different conditions, let's say there's an oil zone within the reservoir, and you reduce the pressure while maintaining temperature. Initially, it will reach the bubble point line, and the liquid will bubble as you lower the pressure. Initially, with high pressure, everything is in liquid form. As you open a valve and decrease the pressure, at a certain point, even while maintaining temperature, it will start producing bubbles. This is known as the bubble point. If you continue to reduce the pressure further, it will create a two-phase situation, with many bubbles and liquid in the vessel. If you reduce the pressure even more, it will become dry gas.

If your surface or stock tank conditions are here, then what was initially in liquid form in the reservoir will be in a gaseous state. However, if your reservoir surface conditions are here, for example, it may be in a two-phase condition. So, when selecting an artificial lift method or completing the wellbore with a specific artificial lift, you must understand the fluid behavior and phase behavior of the fluid. For example, is it an oil well, a gas well, or a condensate well, or does it produce a lot of dry gas or oil? Based on that, you have to choose the appropriate artificial lifting mechanism.

For instance, certain artificial lifts may not be able to handle a significant amount of gas. In such cases, if you don't know the wellbore properties, and during artificial lift pumping, it generates much gas, your system may fail. So, it's crucial to understand this and how to create this phase diagram. Scientists and engineers typically conduct experiments that take a certain amount of reservoir fluid at a specific pressure. Then, they slowly release a valve to reduce pressure.

When you reduce the temperature and pressure, it will start bubbling after a certain pressure and temperature threshold, and you'll reach the bubble point. Then, if you further reduce the temperature and pressure, the entire system will have only one bubble remaining after some time, and the rest will be in a gaseous state. This is called the dew point.

The definition of the dew point is when you first observe the formation of the initial liquid droplet as you reduce the temperature. So, in PVT analysis, experts follow this process: initially, start with high pressure, gradually reduce the pressure, and note the bubble and dew points. They also measure other required parameters for analysis and production system design.

The other lines on the diagram, such as the 75 percent line, 50 percent line, and 25 percent line, indicate the proportions of liquid and gas. As you move from the dew point line to the bubble point line, a critical point is reached where the bubble point and dew point nearly match at specific pressure and temperature conditions. This is the crucial point, denoted as P critical or T critical. Now, if I draw it like this, the area on the left represents the oil zone, and the other part is the gas zone.

So, the dry gas zone is on the right side, and the left side area represents the oil zone or the upper portion. When you change temperature and pressure, the phase will change. You might encounter certain conditions with pure oil or a mixture of oil and gas with some bubbles. As you move from the reservoir to the surface, you must monitor whether it's transitioning from a two-phase state to a single-phase state. If it becomes a single-phase state, it means it's a gas well – there's no liquid present; it's entire gas, even at the surface. However, when the phase changes, the situation becomes different, and you need to consider various factors before selecting any artificial lift method.