Artificial Lift
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Lecture-20 Classification of Artificial Lifts - Part 1

We started the artificial lifting lecture a few years back, and initially, we started with reservoir fluid properties, reservoir, then multi-phase flow, single-phase flow, and different flow properties. Then, we started pumping systems. Now, we will try to link pump and reservoir properties and fluid properties and how they will help to improve our productivity. So artificial lift refers to using artificial means to increase the flow of fluids, crude oil, or water from the production oil. It may be gas also. So, the artificial lift will assist in lifting fluid from the wellbore to the surface when the pressure goes down. Initially, many reservoirs will have very high pressure, so they do not need an artificial lifting mechanism. But with time, the pressure depletes or goes down, so when the pressure goes down, the fluid flow cannot be maintained, maybe sometimes. Sometimes production will be low, or sometimes production will not be there because of the too-low pressure.

So, if low pressure is there and you have seen the phase diagram, you can remember the phase diagram. If let us say initial P_t, initially fluid is here that is single phase zone and because of pressure decrease in the wellbore and it becomes two-phase zone. So what will happen? Much gas will be coming out from the wellbore. So when lots of gas is coming, the artificial lift system may not work, or your whole system of fluid; if the artificial lift is not there, the entire productivity will change. So, in that case, you have to consider changing some parameters in the wellbore, or reservoir, or maybe tubing, or perhaps you have to use an artificial lifting mechanism, and when gas is there, and you are using an artificial lifting mechanism, then you have to take special care so that gas should not interfere the production of fluid through artificial lift. Some artificial lift will be assisted by gas, so if gas is there, it is perfect for them, but some will not help. If gas is there, productivity will be low, or the pump will fail. So the whole system and your whole productivity will be lost. I have shown you the primary, secondary, and tertiary flow in the first few lectures. So primary flow implies natural flow when you drill a wellbore, and fluid is produced naturally because reservoir pressure is higher; because of that, you are getting enough production economically, so that is good that is natural flow or primary production. After a certain time, pressure will go down a little, so you must use the artificial lift. Sometimes, people will put the artificial lift in the primary recovery mechanism, or sometimes, people will put it in the secondary mechanism. Another mechanism is their tertiary mechanism. So, tertiary mechanism, you have to put another injecting wellbore, and you have to inject certain steam or some other thing or enhanced oil recovery technique you have to use. They are usually called tertiary production mechanisms. So, drill a wellbore pressure is very high, you may not need an artificial lift. However, when the pressure goes down, people will initially try to use the gas lift system because it has a higher productivity rate or can produce more. However, if pressure is going down further, so in that case, you may use an ESP system or other systems; if pressure is too low, so in that case, and the flow rate is also very low in that case, maybe you can use a sucker rod pump or positive displacement pump. In a previous lecture, I showed that positive displacement pumps have a lower flow rate but higher pressure. However, centrifugal pumps or ESP systems have a higher flow rate and lower pressure. So if you have a very low flow rate, you can use a positive displacement pump such as sucker rod pump or PCP progressive cavity pump. However, if you have a higher flow rate, in that case, you can go for gas lift application or electric submersible pumping application, but in certain cases, if you have very thick fluid, let us say oil sand or viscosity very high 100-200 CP so in that case you can use progressive cavity pump. A progressive cavity pump is a single screw pump or positive displacement pump; it will work very well if you have high viscosity fluid, but if you have very low viscosity fluid, the PCP may not work properly, but still, you can use actually, but ESP is good for viscosity nearby water so normally ESP is designed for water application. If you are using it for oil well also, it will work, but performance will go down because oil viscosity is higher than water, so oil viscosity is higher and resistance to flow is high. So centrifugal pumps will facility to difficult to push fluid up from well water to the surface. So all the artificial lifting systems have different properties; for example, the sucker rod pump, low flow rate pump, and very high pressure can develop.

PCP has a high viscosity centrifugal pump higher flow rate it will give gas lift will give a higher flow rate, but it will require gas from the surface to inject another pumping system called a jet pump. So the jet pump also needs one surface production system, or at the surface, you need some pumping mechanism to inject certain liquid so that you can increase your productivity; so different wellbores, you have to understand the fluid properties and on the other hand, you have to understand the pumping mechanism, then you have to link, then you can select artificial lifting system and different wellbore will have different artificial lift because wellbores are all different all over the world. If you get two similar wellbore properties, in that case, maybe you can use a similar sort of artificial lifting system. But without understanding the whole artificial lifting mechanism, if you are using any system, that may be your disaster because that may not give proper production or maybe today they will give.

However, tomorrow, they will not give it because sand very high amount of gas may come quickly, maybe within two or six months, so that gas will interfere with the system's productivity, and the whole mechanism will be lost. You must understand wellbore reservoir and fluid flow through a piping system, multi-phase, single-phase, or emulsion fluid. Then, you must understand the surface system, the required pressure, and the different pumping options available. Then, which pump can you fit for certain applications? That is your main purpose in selecting the artificial lifting system, so now select one part.

Next is what? If you are an engineer, a production engineer, or a completion engineer, and you are asked to buy an artificial lift, which one will you buy? You have to understand different artificial lifting mechanisms and how they are applicable. What is life? What is the economic cost? And what are the difficulties in installation? So you have to consider all the parameters, and then you can buy or operate on artificial lifting again. When you are operating, let us say you are a production engineer; you do not care about drilling or production drilling or completion or reservoir, but you still have to understand the reservoir chart, actually when two phases will be starting or a single phase will be starting or when sand will be coming or what is the production and declination analysis result available from reservoir engineers. So that you also have to understand then only you can operate your whole system smoothly because you are a production engineer. Those reservoir people will not be there with you, so you have to understand each part and operate the whole system smoothly and economically.

Then you are a good engineer now where artificial lifts are being used in the US; more than 2 million wellbores and 1 million are being used with artificial lifts. So almost 50% are being used for artificial lift, right, and when you drill a hole, use a gas lift system, especially in offshore wellbores when you are producing oil or gas. So, in the beginning, during the completion stage, people will be putting gas lift mandrel gas lift valve, so that whenever it will be required to inject gas to increase productivity. They can inject quickly instead of removing tubing again and fixing the gas lift mandrel because the offshore operation is expensive; whenever any offshore wellbore servicing or anything is required to bring the whole drilling team and whole drilling vessel again, it will be costly. At the beginning stage, during the completion stage, they will be putting gas lift mandrel; maybe they will not inject gas at that moment where when the natural flow is there, but after maybe 5 years, 1 year, 2 years, and 3 years or sometime when pressure is going down so that time you may need to increase productivity. So that time, you have to inject gas; if I already have the gas lift mandrel fixed, you inject gas from the surface and get more production. However, normally sucker rod pump is not being used for offshore applications because sometimes it will be a very compact area for offshore platforms, so their sucker rod pump will be taking up significant space on the surface, which is not feasible sometimes. But another pumping mechanism, for example, ESP and other things, be okay because they have less surface footprint; the sucker rod pump has a very large surface footprint, so a very compact application will be very difficult to operate.

80% of US oils and US wells are steeper or very low productivity with 10 barrels per day production. There will be very low productivity, and it will work, so in that case, you will not use the gas lift. Normally, there will be a sucker rod pump, very low flow rate, high head pump, or positive displacement pump. A gas lift can often be used, but if you have higher productivity than that in the barrel, it will work. First, you have to understand the different types of artificial lift. In the previous lecture, I discussed different types of pumps, like positive displacement and kinetic pumps. The positive displacement pump has like sucker rod pump, PCP, and the kinetic pump, a centrifugal pump.

Now, here you can see the difference. The term 'artificial lift' implies artificially lifting fluid from the wellbore to the surface. Essentially, you are artificially providing energy to the fluid so it can ascend to the surface. Once there, it can be separated and sent to consumers or refineries. There are three main types: gas lift systems, hydraulic pumps, and normal pumps. Normal pumps come in two varieties: positive displacement and kinetic pumps, which we have previously discussed.

Now, regarding gas lift systems, there are two primary categories: continuous flow and intermittent flow gas lift. You would use a continuous flow gas lift when you have a higher fluid flow rate and productivity. On the other hand, when dealing with very low flow rates, you can opt for plunger lift, chamber lift, or other conventional intermittent gas lift mechanisms. These are suitable for low-flow scenarios, such as 10 barrels per day. Conversely, for high productivity situations, like 10,000 barrels per day, you may want to increase productivity by 10%, 20%, or even 30%. In such cases, continuous flow gas lift can be employed, where gas lift material is typically present, and you can inject gas as needed.

Whenever your productivity declines, for a gas lift system, you require a surface unit for compressing gas. A compressor will be needed on the surface for this purpose. When a compressor is required, it means you need additional energy from the surface. This compressor will be powered by a motor, which in turn will require power from an electric source or an internal combustion engine. Another method is the hydraulic jet pump or hydraulic pumping mechanism. With a hydraulic pumping mechanism, you inject liquid from the surface into the productivity area, which could be the sand phase completion or inflow area. In this area, the pressure is lower. By reducing the pressure in this region where fluid enters the wellbore, you create a situation where reservoir pressure is higher than the flowing pressure. As a result, more fluid enters artificially.

Here's how it works: You inject high-pressure gas and high-pressure liquid from the surface, creating a nozzle. This nozzle generates very low pressure, which I'll explain later. This low pressure effectively draws in more wellbore fluid, mixes it, and transports it to the surface. This process is referred to as a hydraulic jet pump. In some cases, a reciprocating pump or reciprocating engine pump is used, which also draws in wellbore fluid and delivers it to the surface.

In a previous lecture, we discussed two types of pumps: positive displacement pumps and kinetic pumps. Within the category of positive displacement pumps, there are various

options to choose from. However, not all of these options are suitable for oil and gas applications. For instance, there is a drag pump with two thin plates that can deliver fluid when rotated at very high speeds, but it requires a significant amount of space. Due to the space constraints within the wellbore, not all pumping mechanisms can be used. Take, for example, the double screw pump. While it is an option, it may not be suitable because it necessitates a larger diameter. If you look at the illustration, you can see that a double screw pump requires a substantial diameter, which may not be available in your wellbore.
On the other hand, a single screw pump, such as the progressive cavity pump, can be used for wellbore applications. This type of pump is dimensionally constrained, with diameters typically ranging from three inches to six inches, although they can be smaller. For instance, in the same wellbore, you may encounter tubing with a diameter of two and three-eighth inches. The tubing's inner diameter can vary, with thin tubing providing a larger inner diameter and thick tubing resulting in a slightly smaller inner diameter. These differences are influenced by various fluid properties.
Wellbore pressure and other aspects play a role in selecting either thin or thick tubing. These tubing dimensions are typically referenced from API charts. The American Petroleum Institute (API) has established recommended practices, often referred to as API RP, which provide standard dimensions for various oil field equipment.
API has created several documents that specify standard dimensions, materials, and formulas for equipment such as tubing, casing, and chokes. When purchasing equipment from any company, it's essential to verify whether they adhere to API instructions. If they deviate from API recommendations, you should assess whether the product is suitable for your specific wellbore conditions, including checking the suitability of any material changes.
However, when you follow API RP recommended practices, you can align wellbore properties, reservoir properties, equipment materials, and sizes. If a company confirms that they adhere to API recommended practices, it is generally considered safe to use their equipment in your wellbore. This equipment could include tubing, pumps, suckers, or other components.
Positive displacement pumps come in two types: reciprocating and rotary. Rotary types, such as Progressive Cavity Pumps (PCP), can include single or multiple screws. Multiple

screw pumps can be challenging to use in wellbore conditions due to space constraints. They may find utility in surface conditions where space limitations are less stringent. In the wellbore, space is typically limited, with maximum diameters of around 6 inches and minimums as small as 2 and 3/8 inches. For instance, tubing with an inner diameter of 1.99 inches, which is less than 2 inches, can be particularly challenging to handle.

If you want to install a sucker rod pump or any type of pump, I conducted some research on Electric Submersible Pumps (ESPs). However, I couldn't find any pump with an impeller diameter of less than 3 inches. I'm uncertain whether any company has developed or manufactured ESP systems with impellers smaller than 3 inches. Nevertheless, for ESP applications in the oil industry, you can find impellers with diameters of 4, 5, and 6 inches.

ESP systems can also be used in various applications, including submersible pumps for water applications. In water applications, the depth typically ranges from 100 to 200 meters, as these depths typically correspond to aquifers. The primary goal in water applications is not oil production but rather water supply. In contrast, the oil industry targets oil and gas production, often requiring drilling beyond the aquifer zone, usually deeper than 200 meters. To ensure that oil and gas production does not contaminate aquifers, oil wells are drilled deeper than the aquifer zone. Proper cementing is carried out in this region to prevent oil, gas, or water migration between zones. The objective is to reach the reservoir where oil and gas deposits are present.

Reciprocating positive displacement pumps utilize a system known as a sucker rod pump. Sucker rod pumps also come in different types, such as insert and tubing pumps. Additionally, there are variations like Mark 1, Mark 2, and Mark 3 pumps. We will delve into the details of these various sucker rod pumping systems later.

Another type of pump is the rotary pump. As I mentioned earlier, fitting a multiple screw pump into the wellbore can be very challenging. On the other hand, a single screw pump, known as a Progressive Cavity Pump (PCP), is suitable for wellbore applications. PCPs are typically used for pumping highly viscous and thick fluids, such as toothpaste, grease, or in the food processing industry. When you need to deliver a fixed amount of a very thick fluid into a toothpaste pouch, for example, centrifugal pumps or other types won't suffice; only PCPs will do the job.

Electric Submersible Pumps (ESPs) may be suitable for thinner fluids, like water. However, the choice of pump depends on several factors. You can't use them randomly, as properties like temperature, gas content, sand content, and other parameters can affect centrifugal pump performance. These factors must be considered when selecting a centrifugal pump. Regarding PCPs or Progressive Cavity Pumps, you have two main categories: elastomeric PCPs and metallic PCPs. Elastomeric PCPs have a rotor and stator with an elastomeric layer in the stator to reduce leakage flow. This type is commonly used in the oil industry and is versatile and capable of pumping various fluids. However, elastomeric PCPs may not perform well at high temperatures.

In contrast, there are new developments in metallic all-metal PCPs with no elastomer. While these pumps may struggle with pumping thin fluids, they excel at handling thick fluids with lower friction and longer pump life. Metallic PCPs can operate across a broader range of temperatures due to the absence of elastomers or softer materials.

I was talking about ESP or centrifugal pumps. ESPs are typically of the radial or mixed-flow type. When using a radial flow type, smaller dimensions can provide a higher head, whereas with the mixed flow type, if you maintain the same diameter, the flow rate will be higher, but the head will be lower. If you recall the concept of specific speed and the specific speed line, we've seen that positive displacement pumps can generate a very high head, while axial flow pumps produce a lower head.

In the oil industry, radial flow pumps are commonly used. Later, when I teach the ESP system, I will introduce some models to illustrate this further. ESP, which stands for Electric Submersible Pump, is an artificial lifting system, along with gas lift systems, hydraulic pumping systems, reciprocating SRP (Sucker Rod Pump) systems, PCP (Progressive Cavity Pump) systems, and ESP systems. These systems can be considered as different types of pumps or artificial lifting systems, and I will discuss each throughout this course.

We won't go into extensive detail in this brief discussion about SRP, which stands for Sucker Rod Pump. SRP, or Sucker Rod Pump, consists of a long rod called a beam, a Samson post, a fulcrum, and a head referred to as the horse head. From the horse head, a line extends to the wellbore, where a plunger assembly is present. The wellbore is cemented correctly. This assembly is known as the plunger assembly, while the horse head is part of the beam, connected via a slider-crank mechanism. The crank, connecting rod, and Samson post form this mechanism.

So, how does it work? The crank is rotated by an internal combustion (IC) engine or an electric motor. The connecting rod follows suit when the crank moves up and down, causing the beam to move reciprocally. This rotation generates torque, with the motor or IC engine providing the power. This torque is then converted into the up-and-down motion of the beam. The beam pivots on a fulcrum while moving in this manner.

One of the rods connected to the beam extends down into the wellbore and is called the sucker rod. The sucker rod reaches the wellbore, where a plunger assembly is located. You can think of it as a similar mechanism to a hand pump, where you manually operate a handle to draw water. In the case of the sucker rod pump, a motor provides the torque needed for the plunger assembly to move up and down instead of manual operation. The speed of these movements typically ranges from about 10 to 12 strokes per minute, but it can vary. The stroke length, or how far it moves up and down, can range from 3 to 20 feet, depending on the pump model. Some companies market long-stroke sucker rod pumps as better, but I won't delve into that discussion here. I'm focused on discussing the technology.

The sucker rod pump now operates at 10-12 strokes per minute, resulting in a relatively low flow rate. However, a positive displacement pump can generate a very high head. You can visualize this relationship on an HQ curve, where 'H' represents the head, typically measured in meters (or pressure, as we often refer). This metric signifies how high the pump can lift water from the wellbore to the surface in a single pass.

The SI unit system's flow rate 'Q' is measured in cubic meters per second (m^3/s). In field units, it's measured in feet, with teams like cubic feet per second (ft^3/s).

For positive displacement pumps, the HQ curve appears almost vertical. This vertical shape indicates that these pumps can deliver fluid consistently, regardless of the wellbore's depth or the required wellhead pressure. The primary restriction lies in whether the motor, IC engine, crank, connecting rod, and the beam can withstand the high pressures generated by the plunger assembly. Additionally, when dealing with long wellbores, the length of the sucker rod becomes significant. Continuous rods for extremely long wellbores, such as 5 kilometers or 10,000 feet, are not readily available.

Instead, you often need to connect multiple 30 to 40 feet long rods, which can introduce connection points that might pose failure issues.

Furthermore, if gas is present in the wellbore, it can enter the plunger assembly. I'll provide a more detailed discussion on how gas affects productivity in a moment. When gas enters the plunger assembly during its continuous up-and-down motion, certain consequences arise.

The pump may encounter issues when gas is present; it may struggle to pump or lead to a problem known as 'fluid binding,' which could result in rod breakage. Problems can also arise when there is a small amount of sand in the mix. Factors like sand, gas, and viscosity may pose challenges. Fortunately, viscosity isn't typically a significant problem, and temperature doesn't affect the pump as there are no non-metallic components. However, the pump can face issues with deviated wellbores. In such cases, if the long rod rubs against the wellbore, it can lead to wear, ruptures, or leaks, posing a significant problem. Therefore, sucker rod pumps are best suited for vertical wellbores or slightly slanted ones, but excessive deviation, especially in offshore wellbores, can be problematic.

To summarize the key points: high temperatures pose no problem, high velocities can be problematic, low fluid flow rates are acceptable, and increasing the number of strokes to boost flow rate may challenge the mechanical system's integrity. This is because the equipment is heavy, and increasing the stroke rate significantly can lead to high momentum, potentially compromising the system's integrity. Consequently, increasing the stroke length to enhance productivity may not be a feasible solution.

If you aim to increase productivity, you must thoroughly analyze all artificial lifting methods and assess whether the wellbore can support a Sucker Rod Pump (SRP) system for enhanced productivity. If the SRP system isn't suitable, you may need to consider alternatives like ESP or other systems.

When discussing the plunger assembly, it looks something like this: the plunger assembly consists of a rod extending from the surface, featuring a valve at one end. This assembly moves up and down due to the reciprocating motion of the rod. As the plunger assembly moves, it operates with both a standing valve and a travelling valve. The standing valve undergoes minimal movement because it's fixed within the outer cylinder. In contrast, the travelling valve, which includes a ball, moves in sync with the plunger or piston due to its up-and-down motion. This distinction is why one is called a standing valve and the other a travelling valve.

Regarding the gas issue I mentioned earlier, if gas accumulates in this area, it becomes problematic. Engineers and production specialists must find ways to prevent gas from entering this space. If gas somehow enters, operations may need to be halted temporarily to allow gas to escape before resuming. Addressing this gas challenge involves design considerations and installation practices, which I will discuss in more detail later.

Additionally, I'll cover how to identify and prevent gas buildup in this cavity or void area when exploring into the specifics of the sucker rod pumping system in the next lecture.