Artificial Lift

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Lecture-21 Classification of Artificial Lifts - Part 2

Now, I will go to the ESP system. I already mentioned that ESP stands for Electric Submersible Pump or Electric Submersible Pump. Some books refer to it as the ESP pump. However, since we've already established it as ESP, there's no need to say 'ESP pump'; you should use 'ESP,' which stands for Electric Submersible Pump. When specifying an electric submersible pump, some people use Progressive Cavity Pump (ESPCP) to distinguish it from a centrifugal pump. In this case, the 'Electric Submersible Pump' is commonly used for centrifugal pumps. So, let's talk about the ESP, which is a multistage centrifugal pump.

How does a multistage centrifugal pump work? Imagine one stage, two, and three stages, all connected to a single shaft with one motor. This motor powers stage 1, stage 2, stage 3, and potentially many more stages. These stages are placed inside your tubing, which is situated within your wellbore. Perforations are made in the tubing, and cementing is done. Now, fluid enters through the perforations, passing through your motor or pump. The shaft serves the purpose of transmitting torque from the motor to the stages.

So, what exactly is a stage? Each stage consists of an impeller and a diffuser. What is an impeller, and what is a diffuser? An impeller is designed to impel or move something. It has a circular shape with flow channels like blades. When you rotate the impeller at high speed, the fluid you introduce at the center is pushed outward. As the fluid exits, it collects, resulting in higher velocity. This increased velocity is then converted into higher pressure. High-pressure fluid is then directed into another stage, which repeats for multiple stages. For example, if one stage produces 5 bars of pressure, two stages will create 10 bars of pressure, three stages will yield 15 bars of pressure, and so on. Each stage adds pressure, allowing you to increase your productivity.

If the reservoir pressure is initially 100 bars, after going through 20 bars, you might reach 120 or 125 bars. In this way, you can significantly increase your productivity as the liquid level rises.

To operate this system, you need electricity. When electricity is supplied to the motor, a cable is required. The electrical supply comes from the surface, where a pump controller is situated. This controller manages electrical frequency and other parameters from the surface. The surface footprint is negligible; there is no visible equipment except for the control panel, which might be located in a control room.

The electricity then travels to the motor and from the motor to the stages responsible for pumping the fluid. However, between the motor and the stages, there is a section known as the seal section. Why is the seal section placed between the motor and the stages? Electric motors are highly sensitive to liquids like water. Water entering the motor can cause the motor coils to burn because the motor is typically filled with transformer oil or motor oil. If you replace this oil with wellbore fluid, such as water, there's a risk of short circuits occurring inside the motor, leading to ignition. Once ignition and burning occur, the system becomes inoperable, and you'll need to replace the entire setup, which is costly.

What people do is they place a seal section, which is quite long, in the system. This seal section consists of multiple seal layers to ensure no fluid enters or exits from the motor. These seals are essential for protecting the motor because seal failure is the most common failure in ESP systems. The seal section is lengthy and contains various types of seals, such as energy seals, A-type seals, B-type seals, and others like Chevron seals, which are available in the market. Typically, ESP manufacturers for radar pumps or similar applications produce the motor, seal section, and stages.

The number of stages required for a wellbore can vary, sometimes ranging from 10 to 100 stages. Each stage has a length of 1 to 2 inches, with an average height of around 1 to 1.5 inches. So, for 200 stages, you'd have a total length of 200 inches, plus the seal and motor sections. The entire assembly becomes quite long.

The diameter of the shaft depends on the torque requirements. The shaft diameter will also be substantial if the torque requirement is high. However, manufacturers typically aim to minimize the shaft diameter to maximize the fluid flow area, which extends the system's lifespan and reduces costs.

ESP is also a prevalent type of pumping system used for various applications. It finds use in household applications, such as submersible pumps for agricultural and domestic use. However, centrifugal pumps are also prevalent for surface applications, and multistage centrifugal pumps are used for sub-surface applications where pressure needs to be increased while maintaining a specific flow rate. Typically, 2, 3, or 4 stages are employed in such cases. Normally, a 3-stage centrifugal pump suffices for sub-surface applications. You will need a very large diameter pump if you want to achieve the same head and flow rate with a single stage. To reduce the diameter, you can use multiple stages. Similarly, in a wellbore, there are diameter limitations, so the number of stages is adjusted accordingly, impacting the overall length of the pump.

When we delve into the details of ESP systems later, you will understand how the ESP's diameter and the number of stages are interconnected. ESP performance is also influenced by fluid viscosity. If the viscosity is very high, the ESP's performance decreases. In the impeller, as the fluid moves through the impeller blades at high speeds, high viscosity causes the fluid layers to resist sliding over each other, resulting in reduced performance. For example, when dealing with emulsions with a water cut of 70 to 80 percent, the viscosity is very high, and running the ESP system under such conditions can significantly impact its performance.

Now, if you have gas in the system, whether it's a centrifugal pump or an ESP system, it will draw fluid from the wellbore and then impart energy to the fluid as it moves upward in a rotating motion. When gas is present, the issue arises. When the pump draws in the fluid and imparts kinetic energy to it, gas struggles to absorb this energy efficiently due to its low density. In contrast, high-density liquids can absorb a significant amount of energy. Low-density gas doesn't create a strong vacuum, so the fluid is not drawn ineffectively.

As a result, it fails to create the necessary low pressure to draw in the fluid effectively. Ultimately, the system may fail to function correctly, leading to issues. To address this, priming is essential when starting a centrifugal pump. Priming, as I discussed in a previous lecture, involves filling the centrifugal pump with liquid before starting it. Failure to prime the pump can lead to problems.

Furthermore, when running the pump, if it transitions into a two-phase flow, it can pose problems. Referring to the phase diagram with temperature (T) and pressure (P), if the system starts as a single-phase and turns into a two-phase flow before entering the centrifugal pump, it creates low pressure and releases more gas from the liquid. This exacerbates the issue of not being able to draw in the fluid effectively. Consequently, it can lead to vibration, noise, cavitation, and other problems that a typical production engineer may struggle to resolve. In some cases, production may need to be halted, the pump could fail, or you might have to consult your ESP vendor. Understanding the wellbore, reservoir, and phase diagram properties is crucial to effectively selecting and operating your ESP system, thereby increasing productivity.

What is a hydraulic ejector or hydraulic jet pump? We know that if we create a conical shape of a pipe where high-pressure fluid is flowing at a high flow rate, certain effects come into play. When you create a narrow zone within this pipe, something interesting occurs. The same fluid passes through this narrow zone. As it flows through this narrow zone, the velocity at point-1 (V_1) is initially given by Q divided by A_1. Now, at the narrow zone (point-2), the velocity is V_2, which equals Q divided by A_2. A_1 and A_2 represent the cross-sectional areas at points 1 and 2, respectively.

$$V_1 = \frac{Q}{A_1}$$

$$V_2 = \frac{Q}{A_2}$$

The velocity also changes since the area changes as the fluid moves from point 1 to point 2. In other words, as the area reduces, the velocity increases at point 2, which is the nozzle exit position. As velocity increases, it creates low pressure. Bernoulli's equation is represented as follows.

$$\frac{p}{\rho g}+\frac{v^2}{2g}+z=C$$

If we assume that elevation (z) remains constant and the constant value doesn't change, then pressure (P) and velocity (V) are inversely related. If pressure (P) increases, velocity (V) must decrease, and if velocity (V) increases, pressure (P) must decrease. Therefore, at point-2 (P_2), the pressure is lower because the velocity (V_2) has increased.

Now, if you connect a pipe at this point, and it is linked to a wellbore or any low-pressure area, fluid will be drawn in and mixed in this region. This process involves the nozzle, mixing chamber, and diffuser areas. So, high-pressure fluid, known as the primary fluid, enters the system. The primary fluid is high pressure. On the other hand, the secondary fluid is low pressure, and it is also referred to as the secondary fluid. The secondary fluid is drawn in due to the high pressure of the primary fluid. It must mix properly with the primary fluid for efficient operation. Inadequate mixing can lead to incomplete suction despite the creation of low pressure.

To achieve the desired mixing, you need to consider the dimensions of the mixing chamber and the properties of the inlet and suction fluids. If proper mixing occurs with the formation of small bubbles and significant turbulence, efficient suction is achieved. Since V_2 is high, the entire mixture also maintains a higher velocity. At point-3, the goal is to reduce velocity and increase pressure. This is achieved by increasing the piping diameter, particularly in the diffuser section. Once again, you'll find that V_3 equals Q divided by A_3, and as the area increases, velocity decreases, resulting in higher pressure, denoted as P.

$$V_3=\frac{Q}{A_3}$$

A jet pump operates based on Bernoulli's equation, essentially an energy equation. Initially, with high velocity and diameter, the fluid passes through a nozzle, causing velocity to increase significantly and pressure to decrease. This decrease in pressure aids in thorough mixing. After mixing, the fluid passes through a diffuser, where velocity is reduced, and pressure is increased. This increased pressure is delivered to the surface along with the mixed fluid.

This is the fundamental principle of a hydraulic ejector. Different terms may refer to ejectors, such as hydraulic ejectors or jet pumps. When studying this topic, you may encounter various terms. Some other terms include eductor and ejector. Awareness of these alternative names is essential because they may be used interchangeably.

Similarly, in the context of sucker rod pumps, various terms like beam pump, nodding donkey, and SRP may also be used. If an examiner uses different terms, it's important to recognize them and not assume they are outside the syllabus. Remember that different terms can be used for the same concepts, so it's wise to be familiar with these variations. Next, let's discuss the hydraulic engine pump. What is a hydraulic engine pump? It's somewhat similar to a Sucker rod pump with a piston-cylinder arrangement, a ball, and a valve. However, there's a difference in how it operates. Instead of the long rod, you have a setup with two pistons and a connecting rod in a hydraulic jet pump. These pistons are actuated using high-pressure fluid supplied from the surface. This high-pressure fluid powers the motion of both pistons - piston 1 and piston 2.

To visualize this, think of it like a JAMSTROT engine. You provide high-pressure fluid, such as water or diesel, from the surface, and this pressure causes piston 1 to move up and down. The up-and-down motion of piston 1 is then transferred to piston 2, the bottom piston. The bottom piston draws in wellbore fluid and delivers it to the surface.

This concept is known as a hydraulic engine pump. While it's not as commonly used as other methods, it's still a principle that people employ from time to time. On the other hand, hydraulic jet pumps are widely used in various medical applications. In both cases, you require a surface pumping unit that generates high pressure. This high-pressure fluid is directed through the tubing and casing annulus, entering the tubing to lift fluid to the surface.

So, this is similar to a gas lift system, where you inject gas from the surface in a gas lift system. However, in this case, you are injecting liquid from the surface. One question arises: in many cases, another wellbore is employed, where they inject liquid to enhance reservoir properties, not the wellbore itself. In contrast, in this case, a mechanical arrangement increases productivity without modifying the reservoir. When people use enhanced oil recovery techniques, they often employ high pressure, high temperature, or different chemical-related fluids to modify the reservoir. However, in the case of artificial lifting systems, whether injecting gas or liquid, we are not modifying the reservoir; rather, we are focused on improving productivity from the wellbore itself.

Now, let's discuss the gas lift system. Gas lift systems come in two types: continuous and intermittent. Continuous gas lift operates as follows: imagine you have a tubing with a valve at one end, and a separate pipe is from the surface. While in practice, the gas injection may occur in the annular area between the tubing and casing, here, for illustration, I'm assuming a separate pipe. There will also be a compressing system on the surface, a surface compressor. We will delve into compressor details later.

So, this setup creates a nozzle. Let's consider an initial scenario where you have very low productivity due to reservoir pressure depletion. What do you do? You create numerous small bubbles by using a high-pressure nozzle. Essentially, you create a small nozzle that generates these tiny bubbles. If you look at the hydrostatic pressure formula $h * \rho * g$, where 'h' represents the height or column length, you'll notice that pressure decreases as you move upward. So, the pressure is low near the gas injection point, where the column length is high.

As you inject gas and check the pressure at points A, B, and C, you'll find that pressure decreases as the column length decreases. As the column length shortens, the injected gas particles expand, taking up more space. Consequently, you reach point C, where the gas bubble volume is much larger. What's happening here is that you're altering the average density of the fluid. With a column length 'h' and density 'ρ,' the pressure at the bottom or point A can be calculated as $(h) * (\rho) * (g)$.

When you introduce many gas bubbles, you reduce the total hydrostatic column weight because of the gas bubbles. This is due to the change in 'ρ' caused by adding gas bubbles. Consequently, the average fluid column weight decreases, leading to the wellbore drawing in more fluid, resulting in increased production.

The goal is to create a bubbly flow, not a mist or annular one. If you inject excessive gas, thinking optimistically, you might expect higher production to impress your boss.

However, injecting too much gas can lead to another flow regime, such as mist flow, causing a decrease in productivity. Therefore, injecting the optimal amount of gas to achieve maximum production is crucial. The location of the gas injection nozzle and the hydrostatic pressure are also vital factors to consider. These aspects need careful analysis before optimizing your wellbore, which we will discuss further when covering continuous gas lift systems.

Another system is called the intermittent gas lift system. When you have very low productivity, you employ a plunger and a plunger catcher. In situations of very low liquid holdup in the gas well, you encourage the liquid to build up in a column from 1 meter to a meter. Then, you inject gas from the surface at a high rate. The gas injection pushes the plunger up, and as the plunger moves upward, all the liquid above it flows out into the wellbore. When the plunger reaches the surface, you hold it there for some time and then lower it back down. During its descent, the entire plunger collects all the liquid again, and a catcher at the bottom catches the plunger. This process involves several trips, typically 2, 3, 4, or 5 trips per day. Intermittent gas lift is suitable for dealing with low flow rates or low productivity. Sucker rod pumps also handle low flow rates well, and when combined with a high volume of gas, intermittent gas lift becomes a good option for increasing gas well productivity.

Now, let's discuss PCP, which stands for Progressive Cavity Pump. As I mentioned earlier, PCP is a single-screw pump used to pump highly viscous fluids. It falls under the positive displacement category. While multiple-screw pumps are possible, they may not fit within the wellbore due to their larger tubing diameter. Therefore, single-screw pumps, or PCPs, are commonly used.

A PCP setup typically includes a pump or rotor connected to a sucker rod that extends to the surface. In the SRP or sucker rod pump system, the sucker rod provided only tensile force and reciprocating motion. In contrast, with PCP, the sucker rod provides torque from the surface, facilitating rotational movement. In other words, it transfers torque but not tensile force.

A PCP pump typically consists of a stator and a rotor. The stator is hollow and lined with an elastomeric layer on the inside. The rotor, on the other hand, has a helical shape. If you were to cut open the stator, you would see that it houses a rotor that rotates inside. The rotor is metal and does not directly touch the stator's metal surface. Instead, it only interacts with the elastomeric layer inside the stator. Both the rotor and the stator have helical designs to facilitate their operation.

So, inside the rotor, there's a helical stator cavity, and the rotor itself is also helical. When you rotate it, these two helices create a cavity. If I place the rotor here, there will be a cavity, and this cavity will be filled with liquid. As you rotate it, the cavity progresses. This is why it's called a progressive cavity pump—the cavity progresses as the rotor turns. When you rotate the rotor, the cavity progresses, taking in a fixed amount of fluid, and this process continues. So, continuously, this cavity progresses. If you check Wikipedia, there's an animation someone has uploaded that illustrates how the cavity progresses as it rotates. It rotates and progresses like this, transferring a fixed amount of fluid with each rotation. This is a positive displacement pump, capable of generating any pressure or head. It can also be used as a metering pump, which means it can deliver a fixed amount of fluid if you control the rotational speed. For example, with two rotations, you get 100 millimeters; with three rotations, you get 150 millimeters. This way, it can be used as a metering pump.

PCP has various applications beyond the oil and gas industry. It can pump thick fluids such as toothpaste and grease. I filed a patent some time ago. While I initially developed it for the oil industry, the company used it for designing a left ventricular assistive device for humans. This device can provide continuous fluid flow to the body in heart ailments, serving as an alternative to the heart. That's why the company added it to their portfolio of health inventions.

The rotational speed of PCP typically ranges from 3 to 500 RPM. Due to its long rod, it cannot be installed in very deep wellbores. In some cases, ESPCP (electric submersible PCP) is used. In ESPCP, the motor is submerged in the wellbore. The concept of surface-operated and ESP came about because, initially, there was no Variable Frequency Drive (VFD) concept or VFDs were not available in the market. Now, with VFDs, you can control the speed. Normally, the 300-500 RPM motor produces 1400 or 2800 RPM speeds. You need a VFD or a motor with a different design to reduce the speed. They have incorporated features like changing the frequency and motor design parameters in newer designs to produce lower speeds. These motors are submerged in liquid, giving rise to ESPCP, which stands for electric submersible progressive cavity pump. However, in ESP systems, the term ESP is used exclusively.

Now, let's discuss another type of pump known as the metal PCP. Metal PCP looks like this. In elastomeric PCP, I mentioned an elastomeric layer and a metal cover, and the rotor rotates inside. In metal PCP, they remove the elastomer and use all-metal construction. In this case, there's a stator inside, a rotor, and a cavity. The rotor is metal, and the elastomer is absent."

When a helical rotor and stator are present with elastomer, it creates a leak-free pump. But if you are using all metal components, it will not be leak-free. With elastomer, the actual leak principle becomes like this: If I have a rotor with a circular shape and an elastomer, the rotor diameter can be slightly larger than the stator's inner diameter. This is why it creates a leak-free condition. Pressure P_1 and pressure P_2, if P_1 is very high and P_2 is lower, then fluid tries to pass through this gap. When fluid attempts to pass through the gap and the elastomer is slightly depressed, the leakage will be very low. However, in a metal PCP, there's no elastomer. You have only metal components, such as the rotor and stator. When the rotor rotates, creating pressure 1 and pressure 2, there is no depression of elastomer. Because there is no depression of elastomer, the leakage rate will be higher.

So why do people develop all-metal PCP? All-metal PCP is developed because they want to use it in high-temperature wellbores. Elastomers can be problematic in high-temperature wellbores because their lifespan is lower at high temperatures. To extend the PCP's life, they remove the elastomer and create an all-metal PCP. However, manufacturing an all-metal PCP is challenging because it requires very high precision. If precision is not maintained, the system can fail. Nevertheless, some companies have successfully produced all-metal PCPs. On the other hand, elastomer-based PCPs are manufactured by several companies, but they have temperature limitations due to the elastomeric components.

If you are using all metal, the temperature may not be limited. However, leakage issues are present in all-metal PCPs. If thin fluid is being pumped, then leakage can be a significant problem, but for thick fluids, leakage is generally manageable.

We have seen different types of artificial lifting systems: SRP, ESP, PCP, gas lift, and jet pump, with various subsections like metal and all-metal PCPs. Given this variety, what are the selection criteria? Well, you need to consider well completion profile, geographic and environmental conditions, reservoir characteristics (whether it's two-phase or single-phase flow, sand production, or decline rate), rate analysis, reservoir pressure, wellbore productivity, fluid characteristics (including solid content, gas content, and temperature), and viscosity. Viscosity can change due to changes in fluid properties, such as gas content or increased water cut, affecting pump performance and potentially leading to failure.

Net positive suction head (NPSH) is another critical factor to evaluate. Every pump requires a certain inlet pressure, and centrifugal pumps, for instance, demand a larger NPSH because they move fluid at a high rate. However, low NPSH might be acceptable for pumps like sucker rod pumps when dealing with small fluid volumes. But special considerations are needed if gas or sand is present at the inlet.

Priming and dry running are crucial aspects to consider for pumps like centrifugal pumps, ESPs, and PCPs. Noise should also be taken into account. To avoid these negative aspects, pumps must be properly primed. I've developed this chart to provide a rough idea of the possible capabilities of various pumps. The numbers are not exact, but they illustrate the general range. For example, SRPs can handle up to around 16,000 feet (5 kilometers) in length. ESPs can also operate at significant depths. PCPs may have limitations due to their long rods, but with ESPs, the depth can be extended. Plunger lift systems have limited fluid capacity. Gas lift systems excel in fluid capacity and handling high viscosity. PCPs perform well with high-viscosity fluids and are suitable for handling sand. SRPs can be used with sand to some extent, while other pumps may face difficulties. Gas lift systems and jet pumps are less susceptible to issues with sand. High temperatures may pose challenges, especially if elastomers are used, as they may deteriorate.

Regarding speed, SRP operates at a very low speed, and plunger lift systems also have a low operating speed, resulting in higher costs. Regarding well deviation, PCP and other systems may be suitable, but SRP can be challenging. Regarding dry running, SRP, ESP, and PCP are not ideal, whereas jet pumps might be feasible. Gas lift and other systems can work well for gas wells, but SRP, ESP, and PCP need to be cautious when dealing with gas. Reservoir pressure is another consideration, with SRP being suitable for low-pressure conditions, while ESP may require sufficient inlet pressure, which must be considered. Priming is necessary for SRP, PCP, ESP, and gas lift systems, whereas priming may not be a concern for other systems. If you have a high gas-to-liquid ratio, certain ESPs, PCPs, and SRPs may need to avoid gas. This concludes the lecture.

THANK YOU VERY MUCH