Artificial Lift

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Lecture-27 Sucker Rod Pump (SRP)- Part-6

Regarding the plunger and cylinder clearance, I previously mentioned that there isn't much clearance, but there will be some clearance. Why? Imagine a plunger with a valve seat like this, placed inside a cylinder barrel. Now, there's a ball in between, and within this area, there is clearance. When there's clearance, it implies there will be leakage. When the piston is attempting to move up, what happens is that the traveling valve closes, and the standing valve opens. If, during this movement, the pressure above the piston or plunger is significantly higher than the pressure in the cylinder area (as I mentioned earlier, P tubing and P cylinder with a substantial pressure difference), the high-pressure fluid will attempt to flow back into this area.

If the fluid has high viscosity, it won't leak back into the cylinder due to its thickness. However, if there is very low clearance, it can be helpful, but for mechanical reasons, some clearance needs to be allowed to ensure smooth piston movement. For this purpose, there's a formula to calculate the leakage rate. We've already calculated the actual flow rate as APLS, which involves the volume of the cylinder and how many times it travels per second. This gives us the theoretical volume. However, in practice, the actual volume will be lower due to leakage. The leakage formula is as follows:

$$Q_L = \left(\frac{\pi D \Delta P (DC)^3}{\mu L (2.32 * 10^{-7})}\right)$$

Many authors have proposed different formulae for this, but we will stick to a single formula for our calculations. With this formula, we can determine the theoretical head, pressure, and flow rate you can expect under ideal conditions and calculate the volumetric flow rate from your pump.

So, what is π? π, you know, is the constant 3.14. D represents the plunger diameter, which is given in inches. I think it is given in inches. ΔP stands for the pressure difference between the cylinder and tube, calculated as P_tube minus P_cylinder. This pressure difference is usually relatively high. Mu represents viscosity, measured in cP. L stands for the plunger length, which is given in inches.

Additionally, there's DC, which represents the clearance. Clearance refers to the gap between the plunger and the barrel's inner diameter. D is the plunger diameter, and d is the outer diameter, so DC is calculated as (D - d) divided by 2. DC indicates the clearance, representing the gap between the diameters, D minus d.

From this formula, we can observe that QL is directly proportional to D, directly proportional to ΔP, directly proportional to DC cubed, and inversely proportional to mu and inversely proportional to L. Other factors remain constant. If we increase D, the diameter QL increases. Similarly, if we increase ΔP, QL increases, regarding DC, the clearance. Suppose we double the clearance value results in 8 times more leakage because of the cubed term. Viscosity, mu, is inversely proportional to L, the plunger length. Increasing plunger length (L) results in an inversely proportional relationship with QL.

Typically, plungers are not made very long, but they are often used at lengths of 3 or 4 feet in the oil industry. This is because increasing L (plunger length) can lower the Q leakage flow rate.

Now, let's solve a problem. The given values are: D = 2.5 inches, ΔP = 2000 psi, DC = 0.003 inches, L = 48 inches, N = 15 SPM, stroke length = 48 inches, and mu (viscosity) = 3 cP. Using the formula, we can calculate Q as follows:

$$Q = \pi \cdot 2.25 \cdot 2000 \cdot (0.003)^3 \cdot 3/(2.32 \times 10^{-7})$$

This results in 11.43 cubic inches per minute. This represents the cubic inch volume it delivers per minute. If you want to convert it to barrels per day, you'll need to know the conversion factor between inches and barrels, and you can then make the conversion. You have obtained the leakage flow rate, denoted as Q or QL, and the theoretical flow rate, which we previously calculated as (AP*L), where L is the stroke length.

So, if we obtain the theoretical flow rate and leakage flow rate, we can calculate the volume efficiency, denoted as eta volume or volumetric efficiency, often abbreviated as Ev. You can use the formula: (Theoretical Q - Q Leakage) / Theoretical Q. This equation provides the volumetric flow rate. If you are given different clearance values, pressures, or any other variables, you should be able to calculate them using this formula.

Now, let's address another formula problem. We must calculate slippage for various clearance values, stroke lengths, and flow rates for this. Similar to the previous problem, we will solve this one accordingly.

Gas interference is common when using a sucker rod pump, reciprocating pump, or artificial lift system. These systems often encounter a liquid mixture, including water, oil, gas, and sometimes sand. Ideally, you want a situation with just liquid, but even then, you need to consider the water-to-oil ratio to optimize economic efficiency. If you have to deal with more sand or water, you must manage them effectively while evaluating the economic benefits of your wellbore.

When you have gas, it can be beneficial because you can sell it. However, if the presence of gas interferes with your pumping operation, you might not get either gas or liquid. Gas interference is problematic. Specific issues arise in a piston-cylinder or plunger-barrel assembly if the fluid is a mixture of liquid and gas. In this scenario, the gas tends to expand during the suction stroke. This expansion results in lower pressure because the plunger moves upwards, and the pressure in the cylinder area must be lower.

When gas is present, it creates some challenges. Initially, as the gas expands, the pressure difference between wellbore pressure (which is higher) and cylinder pressure (which is lower) decreases. In contrast, the pressure difference remains higher when you have a liquid. When the pressure difference is more down, only part of the cylinder area gets filled with liquid. It becomes only half-filled. As the plunger moves downward, the gas in this half-filled area gets compressed, and then liquid enters the traveling valve and moves upward. Gas undergoes a continuous cycle of compression and decompression.

When the plunger moves upward, the gas expands, and the entire cylinder area does not fill with liquid. This variation from the assumption of a completely liquid-filled stroke impacts the volume flow rate formula (Pd or Ap*l). Stroke length typically assumes a completely liquid-filled stroke, but it's only partially filled in this case. Gas compression and expansion lead to a lower volume flow rate. Sucker rod pumps can handle 70%, 80%, or even 90% volume flow rates. With 80%, the sucker rod pump can still function effectively. However, when the volume flow rate drops below 60%, the pump may not deliver any flow. This situation is known as a gas lock, where the cylinder is filled with gas, and the plunger moves up and down, causing the gas to expand and contract. The primary goal of pumping liquid is not achieved during this expansion and contraction.

This means that your system is operational, and you're providing electrical energy, but you're not pumping. Consequently, you'll incur an economic loss. I discussed this with some engineers, and they mentioned that in such situations with gas lock, you need to shut off the pump and allow for leakage. We've already calculated the leakage through the plunger and barrel, where there might be some small gaps. There could also be some gaps in the traveling valve.

The cylinder cavity fills with liquid by stopping the pump and permitting some leakage, and the gas can escape. This stoppage can last for several days. Typically, production engineers strive to avoid gas locks and implement mechanisms to prevent them. We'll discuss later how to avoid it.

Now, let's address another issue mentioned in the title: fluid pounding. What is fluid pounding? In this scenario, you have liquid with some portion of very low-pressure gas. When the piston moves down or up, liquid enters the cylinder area. In the cylinder area, some parts contain liquid, while the majority holds gas. When the piston or plunger moves down, its speed increases due to the fluid and wet load. When it moves up, the speed decreases. However, the piston or plunger moving down and hitting the liquid surface at high speed can create substantial vibrations. These vibrations can potentially cause the rod to buckle. This is known as fluid pounding, and it leads to rod buckling.

What's happening is that the rod and the entire mass are moving at a very high rate, and suddenly, you stop the plunger end. When this occurs, the plunger hits the bottom, and the entire pressure pulse or vibration isn't transferred to the top. Only the bottom portion stops, while the top portion remains in motion. This results in the motion suddenly stopping, creating a certain compressive force. When there's a compressive force, it leads to a buckling load. I'll discuss the failure modes later.

One failure mode is due to tensile failure of the rod. Another failure mode is buckling. Buckling occurs when a very long, thin rod is subjected to pressure, causing it to bend. It may touch the tubing when it turns this way, creating friction. In sucker rod systems, the rods can be long, around 25 to 30 feet, and connected with couplings. Several rods are coupled together, making them extend for kilometers. These couplings can fail, and if the rod rubs against the tubing, it can lead to problems. Fluid pounding can cause an immediate system failure, vibration issues, and rod failures. Hence, it's crucial to avoid fluid pounding and gas loading.

This phenomenon is known as gas interference or fluid pounding. In the case of sucker rod pumps, when you have gas-rich oil or a gas-rich wellbore, especially when a significant amount of gas is present, or when the two-phase flow is generated during pump intake due to crossing the bubble point line, you may encounter gas lock or fluid pounding issues, leading to pump failure or even production stoppage. Therefore, avoiding fluid pounding and gas interference is essential when dealing with gas inside your wellbore.

How can you avoid this? There are essentially three techniques, although other techniques may also be available. Let's first discuss these three techniques.

One approach is to have a casing with perforations where your barrel and plunger are positioned. In this scenario, oil and gas can enter, potentially causing a gas lock if gas enters the system. To address this, you need to prevent the gas from entering. How can this be achieved? A suggested method is natural gas anchoring. The idea is to place your pump intake area below the perforations. Here's how it works: your perforations are located here, which may be your reservoir. You then drill further and position your pump intake below the perforations, with your plunger positioned above it.

In this configuration, when fluid enters from the perforations, which may contain both oil and gas, the gas will escape through the annulus. You have tubing inserted through which all these components pass, and the liquid will flow down and collect below. Thus, only the liquid enters the pump while the gas escapes through the annular space. This method, known as a natural gas anchor, allows the gas to escape through the annulus while the denser liquid falls down and enters the pump.

So naturally, you are separating by positioning the pump intake below the perforation. When oil and gas enter, the gas will rise due to its lower weight or higher density, while the heavier fluid will descend and enter your pump. This way, you separate the gas, which is a straightforward process.

Another approach is the "poor boy" gas anchor, which operates similarly. It involves using a separate instrument with numerous pores where your pump intake is located. In this setup, oil and gas enter the instrument, but the gas escapes, allowing the liquid to continue down and enter the pump. The mechanism for the poor boy gas anchor is similar to that of the natural gas anchoring system, which is commonly used in perforation areas. You place this instrument in the perforation area, and it effectively separates the gas, allowing it to rise while the liquid flows downward into the pump.

Another method is the packer-type gas anchor. In this case, a separate pathway is created for gas to escape and for liquid to enter. However, this approach is less commonly used. The natural gas anchor system is widely adopted because of its simplicity—just position the pump a few feet below the perforations. It's important to ensure that the wellbore pressure or pump intake pressure is sufficiently high to assist in opening the traveling valve to the standing valve. If the pressure is too low and a vacuum is created when the plunger moves up, gas can be generated due to low pressure inside the cylinder or wellbore, potentially leading to two-phase flow and gas issues despite the gas anchor system being in place.

When designing the entire system, it's crucial to consider the properties of the reservoir fluids. Even with the gas anchor system in use, gas may still pose a problem. Various companies have developed anti-gas lock designs and gas lock breaker mechanisms to address this. Researchers and students can explore patents and conduct comparative analyses to find effective anti-gas lock mechanisms and potentially contribute new ideas to the field.

First, let's examine the top picture. In the top picture, you can see a barrel, a standing valve, a valve cage, a plunger, and a travelling valve. During the downstroke, the travelling valve opens a pathway, with some holes here. Fluid enters through these openings and moves upward. This represents the downstroke. When the piston or plunger moves downward, the travelling valve is closed, while the standing valve is opened.

This is the upstroke. When the plunger moves upward, the bottom or standing valve opens, and the travelling valve closes, allowing fluid to enter the cavity. Pushing the plunger downward, the bottom valve closes, the travelling valve opens, and the fluid moves up the plunger. This is how you deliver fluid. However, if you have gas, it will fill this cavity area, causing a problem that needs to be addressed. So, there are several techniques available to solve this issue.

I will explain two of these techniques. One method involves using a variable slippage pump manufactured by a particular company. What is a variable slippage pump? It consists of a standing valve and a travelling valve like this. If this area is filled with gas, and the plunger is moving upward, you move it up enough so that the pressure in area A (let's call it B) allows fluid from A to enter B because you intentionally provide a more significant leakage path. When the plunger and barrel are correctly designed, there should be no gap between them.

Small clearances exist, but they are not significant. However, you enlarge the barrel size when you employ a variable slippage pump. With an enlarged barrel size, the clearance between the plunger and the barrel area becomes too large when the plunger moves up to a certain level. This clearance area becomes quite significant. When the clearance is ample, leakage becomes substantial, as seen in the QL formula.

$$Q_L = \frac{\pi \bar{d}\, \Delta p (d_c)^3}{\mu L \,(2.32 \times 10^{-7})}$$

QL is proportional to $(DC)^3$, where DC represents the clearance. By intentionally creating a larger clearance, gas in location B can escape and reach location A, while the liquid slowly moves downward. Gas is effectively separated as the liquid moves down, and your chamber in location B becomes filled with liquid. This eliminates the gas lock issue, ensuring smoother operation. However, it's essential to note that this approach reduces the volume flow rate, as you are introducing additional clearance (DC). With this setup, you experience a lower flow rate with every stroke. Nevertheless, the gas lock problem is effectively resolved.

So, problem-free operation is ensured, but with a slight reduction in performance. This is why the company is emphasizing this approach in its marketing efforts. Another concept involves a mechanical plunger pin. The mechanical plunger pin operates as follows: a valve cage is equipped with a pin. When the plunger moves downward, the pin within the standing valve cage interacts with the travelling valve ball, forcibly unseating it. The ball shifts from its original seating position, causing significant leakage. Allow me to illustrate this with another figure. Imagine this as the initial condition, and here's the plunger at the bottom. Due to the pin, the ball is lifted, creating a path for gas to escape.

Consequently, during each stroke, as the plunger nears the bottom, some liquid may also leak out, but the gas is allowed to exit. This approach is referred to as the mechanical plunger pin, and it ensures that gas does not accumulate. This is one technique. Another technique is known as the gas vent pump. In this design, there's a plunger with a gap. When the piston or plunger moves upward and crosses this gap, the following occurs: there is a gap.

So, this is the gap, and there is a piston. When the plunger moves above the gap, at that time, gas will escape, and liquid will enter from the gap. They refer to this as a gas vent pump. So, any gas accumulating in the B or cylinder area will be vented out, and liquid can enter. This eliminates gas lock. Again, you must sacrifice a certain amount of fluid for every stroke. Your volumetric flow rate will be slightly reduced, but you will avoid gas lock or fluid pounding.

Similarly, other designs are also available, and you can explore them. I have prepared some comparative analyses as well. Feel free to examine different methods. I have explained the key designs. I conducted this work. You can study it and determine if additional information needs to be added. Several gas lock breaker technologies are available, some in the form of patents, and some companies have produced products as well. These include one or two-valve plungers, gradually enlarging plungers, gas vent pumps, gas compression chambers, mechanical plunger pumps, and top valve pumps. In my paper, I outlined the positive and negative aspects. I encourage students to review this paper and consider adding more points or making adjustments: pump control, pump control. Now, you know that your sucker rod pump may encounter gas.

Gas lock breaker system	Positive side	Negative side
Two valve plunger pin pump	The lower valve has higher surface area and the higher force helps opening the lower valve.	After opening the lower valve, there does not remain any existing force to open the upper valve.
Gradually enlarging barrel pump	Gas can not be accumulated. Metal to metal sealing works.	Large leakage, low volumetric efficiency [summary]. Seal can not be used.
Gas vent pump	Gas can not be accumulated. Metal to metal sealing works.	Large leakage, low volumetric efficiency. Seal can not be used.
Gas compression chamber pump	High compression ratio will help to get the valve opened during down stroke.	The top section of plunger requires a dynamic seal and the seal is exposed to sand and well fluid. The seal wear limits the pump life.
Mechanical plunger pin pump	TV opens during down stroke (neat BDC) of the plunger.	Large leakage, low volumetric efficiency.
Top valve pump	Top valve remains closed during down stroke and the differential pressure in C_3 gets reduced. Hence differential pressure on the TV becomes lower which helps to open TV easily.	The top valve requires one set of seal and the seal is exposed to sand and well fluid. The seal life becomes lower.

You have a gas anchoring system, but gas is still entering. Now, you decide to replace your bottom assembly with a newer anti-gas lock system. However, your engineers are saying it's still not working. You have to implement some pump control measures. Pump control means no filling of your cavity or cylinder because a low amount of liquid enters. When the cavity fills with gas, it leads to multiple problems.

So, what can you do? You have two options. First, you can switch off the pump for a certain period. The second option is to reduce the pumping rate. For instance, let's say your well produces 5 barrels of liquid per day, but your pumping rate is set at 10. This means there is a shortage of 5 barrels. When the pump tries to pump 10 barrels but only 5 are available, it can draw in gas. This gas can pose problems.

In such cases, you can either shut down the pump for a specific duration or decrease the pumping stroke. The design flow rate is calculated using the formula, considering the maximum inflow capacity per day and the pump's volumetric efficiency, which depends on how many hours you run the pump. However, one challenge is dealing with gas swell, with a maximum flow rate of 300 barrels per day.

I'm going to write "small b," "small d," "small b," "small d" again. I'm unsure if there's a standard unit for these, which might explain why many books present them differently. SRP (Sucker Rod Pump) determines the pump's working rate. The volumetric efficiency is 80 percent. So the design flow rate is calculated as follows: (300 * 24) * (0.8 * 0.2) --> which equals 450 barrels per day. Everything should be fine if you plan to run it for 20 hours. However, if you want to run it continuously for 24 hours to increase production, you might encounter problems.

$$\text{Design Rate} = \frac{\text{Maximum Inflow Capacity} \times 24\,\text{hrs/day}}{\text{Pump Volumetric Efficiency} \times \text{hrs pumped/day}}$$

- A gas well has maximum Q_l of 300 b/d and an SRP lifts the fluid. For what rate should the pump
- be designed so that gas lock or fluid pound can be avoided? Assume a pump volumetric efficiency = 80% and operated for 20hrs/day.

Sol: Design Rate = (300X24)/(0.8X20)=450b/d.

Variable frequency drives are also used in these systems. With a variable frequency drive, you can adjust the electrical frequency, which, in turn, changes the motor's frequency. This adjustment affects the gearbox speed, reducing the strokes per minute (SPM). While lowering the SPM might seem fine, you need to monitor whether your pump fills with gas, such as 80 percent of the material being gas and only 70 percent liquid. To determine this, you should study your pump or dynamometer curves and use that analysis to assess if the wellbore has a problem. We will delve into this analysis in the following lecture.