Artificial Lift

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Lecture-46 ESP Numerical Problems-Part 1

Good morning, everybody. Today's lecture is about calculating ESP (Electric Submersible Pump) systems. You have seen the system from the surface to the subsurface wellbore, including the downhole pump setting area for different equipment. If I were to draw the ESP system again, it would look like this:

I have one casing, which is usually larger than the tubing size. Casing sizes are standardized and follow API tables. When selecting casing sizes, it's important to adhere to these standards. For example, you may find that the casing size is 7.58 inches, but there won't be an option like 7.1 inches. In such cases, you should select the nearest casing size as per the API table.

API standards are critical because they ensure that all the electrical and mechanical equipment, such as the ESP system and monitoring system, can be fitted properly into your system. Casing sizes can be 7.58 inches, 8.58 inches, or 5.5 inches, among others. These sizes are typically specified by their outer diameter. If nothing is specified, assume it's the outer diameter. However, if the inner diameter is explicitly mentioned, you should use that information. You can find the inner diameter in the API table, which provides various inner diameter options.

Tubing calculations follow a similar process. It would help to consider whether you are calculating the tubing's inner or outer diameter, depending on your fluid flow requirements. This course doesn't cover tubing design extensively, but it's essential to keep in mind that the tubing's wall thickness plays a crucial role. Thin-wall tubing captures less stress but may not support the required loads. In contrast, thick-walled tubing increases the overall weight and may face challenges related to elongation. Optimization is necessary to determine the optimal tubing size, thickness, and diameter. A smaller diameter may result in higher friction losses and increased pumping power requirements, while a larger diameter could lead to issues like sand settling and multiphase flow separation, where heavier phases sink while lighter phases rise. Therefore, proper tubing sizing is crucial for optimizing production and avoiding problems such as high pumping power demands, sand settling, and multiphase flow separation.

So, you have to calculate the tubing size properly. Inside, you will have a pumping system such as ESP, SRP, or some other pumping systems. Inside the casing, there is tubing, and there are perforations. We are assuming this is your oil and gas zone, and you are perforating it to extract your production. So, from here, there will be a casing head, and then it will be diverted, leading to the Christmas tree. This mechanical arrangement includes the pump, which will be located at the bottom area. The pump may not necessarily be placed near the perforations; it could be below or above them. If the pump is placed above the perforation area, you have to check the available Net Positive Suction Head (NPSH). If the NPSH requirement is higher than what the pump provides, you have to reduce the pump height. By lowering the pump, the NPSH available will increase. Conversely, the NPSH available will decrease if you move the pump up. Therefore, you need to check the pump setting depth based on the pressure in your wellbore. You have to calculate the total hydrostatic head from the pump to the surface. There will also be requirements for piping to reach the separated system. If the system needs a certain pressure, you must calculate the separated pressure plus piping pressure, considering any elevation, wellhead pressure drop, frictional pressure drop, and hydrostatic pressure drop. The pump must develop a head equivalent to all these pressures. The pump can be installed vertically or horizontally. For instance, if you have a horizontal wellbore, you can install the pump horizontally or vertically, depending on the available head. Consider the actual vertical depth when calculating the hydrostatic head, which refers to the true vertical depth. You also need to calculate the frictional pressure drop, which this length determines. I'm using the term 'del P friction,' which might not be in your textbook. It represents the true vertical depth. The true vertical depth provides hydrostatic pressure (P hydro), and the frictional pressure drop must be calculated. After the wellhead, there might be some frictional losses in the pipeline. There could be a choke, a pipe, and then it goes to the separator. This means your pump must deliver a certain amount of energy to overcome all these pressure drops, including frictional pressure drop, hydrostatic pressure drop, wellhead pressure drop, piping pressure drop, and elevation-related pressure drop. The pump must provide enough pressure to reach the separator. The separator also requires a certain pressure; your ESP must deliver all the necessary power and pressure. If there are electrical components, such as a motor, they will be located at the bottom, as we discussed earlier. The motor receives power from the surface. Electric cables come down and connect to the motor. The electricity passes through a junction box. From there, it goes to the switch box, VFD controller, and other equipment. A transformer is also part of the setup. If, for example, you are providing 11,000 volts, you may not need that much voltage. A step-down transformer reduces the voltage from 11,000 to 440 or 4,000 volts. The electricity goes through the junction box, which could be a vent box, allowing any gas from the wellbore through the cable to escape. This junction box connects the cable from the wellbore to the cable coming from your switch box. These are all connected to your junction box (CTI1), switch box (TCH switch box), and transformer. When installing any subsurface electrical submersible pump, you need to know how much pressure you are generating, the casing size, tubing size, flow rate, fluid properties (including the presence of sand or gas, gas-liquid ratio, and sand properties), and whether it is a two-phase flow. Understanding the phase diagram is also crucial. You need to assess the pressure drop from the bottom of the wellbore to the surface. Additionally, check the sand phase completion and the pressure drawdown. If the pressure drop is exceptionally high, it could create NPSH problems. If you follow the information from the previous lectures, you'll be aware of wellbore pressure, reservoir pressure, and how reservoir pressure is lost as the fluid passes through the reservoir channels. Sand phase completion results in a pressure drop. The fluid then enters the wellbore and flows through the PWF, as we've discussed in previous lectures. After calculating the flowing pressure, if it's sufficient, that's good. If not, you may need to install an inducer or a small axial pump to provide extra pressure to the main centrifugal pump or ESP. The ESP will then deliver the fluid. If you're dealing with a two-phase flow or have free gas due to low NPSH, gas may escape from your fluid, causing issues. To prevent this, you must install a gas separator before or after the motor.

Regarding the gas separator's location, it should be placed just before the pump, at the intake section. This gas separator will also contain an inducer, which provides additional NPSH. There is another crucial component to remember between the gas separator and the motor, called the protector. The protector's primary function is to safeguard the motor, not the pump. The motor contains a dielectric fluid, and the protector is responsible for protecting the motor.

Electric power is supplied to the motor via the electric cable, and the motor provides rotation. This rotation is transferred through a long shaft that connects from the motor to the protector, the gas separator, and then to the pump. The shaft has multiple connection points, including radial bearings, to prevent vibrations during rotation. Additionally, thrust bearings are incorporated at various locations to ensure that axial load is not transferred to the pump, gas separator, protector, or motor. The shaft is primarily designed to handle torque, as power is related to torque and rotational speed, as expressed by P equals T * ω, where P represents power, T represents torque, and ω represents rotational speed.

If you need to calculate friction or pressure drop, you can find several charts or use approximate formulas. Hydrostatic pressure can be calculated using single-phase and multiphase flow correlations. Single-phase flow may vary in viscosity, such as oil-water emulsions. When gas bubbles are present, multiphase flow occurs, and you have to decide whether you are working with a separate or homogeneous model. While various software options are available, it's essential to understand the underlying principles well. Manual calculations remain a valuable skill.

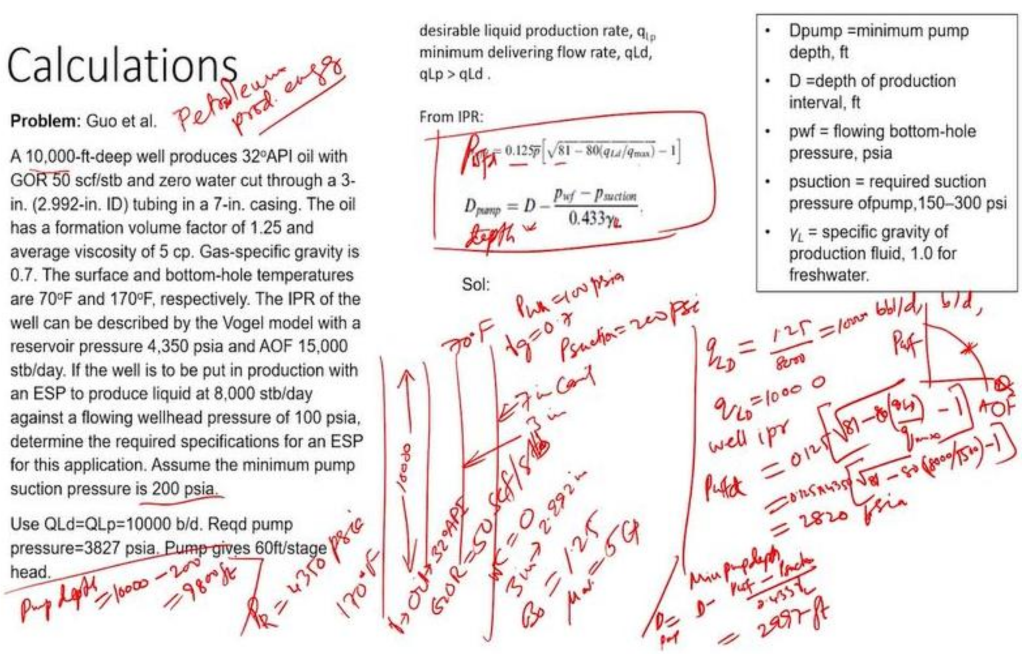
Let's try to work through an example using manual calculations. This problem is taken from the book by Guo et al., titled 'ESP Manual,' which serves as a reference for this course. The scenario involves a 10,000-foot-deep wellbore with 32-degree API oil and a specified gravity. The gas-oil ratio (GOR) is given as 50 standard cubic feet (SCF) per stock tank barrel (STB). When referring to standard cubic feet, it implies the conditions of 14.7 psi pressure and 60 degrees Fahrenheit, which are standard for stock tank barrel (STB) conditions.

For the gas-oil ratio (GOR), you are measuring it with zero water cut, denoted as WC equals zero. The provided information includes a 3-inch tubing, with the tubing's size specified as 3 inches. This means that the outer diameter is 3 inches, and the inner diameter is given as 2.992 inches. If the problem does not provide the inner diameter, you may need to refer to an API table to find the appropriate inner diameter. This inner diameter is essential since the fluid flows through the tubing.

The casing is 7 inches in size, which indicates the outer diameter. The inner diameter of the casing will be smaller, typically around 6.5 inches. The oil has a formation volume factor (Bo) of 1.25, and the average viscosity is 5 cP (centipoise). It's worth noting that the average viscosity may vary as the fluid moves from the wellbore to the surface due to changes in pressure and temperature. The gas's specific gravity is 0.7 (γ_{gas} equals 0.7).

Both surface and bottom-hole temperatures are provided, with the surface temperature at 70 degrees Fahrenheit and the wellbore temperature at 170 degrees Fahrenheit. The well's inflow performance relationship (IPR) can be represented using Vogel's model, with a reservoir pressure of 4350 psia (absolute). The absolute open flow (AOF) rate is given as 15000 STB per day (Stock Tank Barrel per day).

If the well is to be produced using an Electric Submersible Pump (ESP) to produce 8000 STB per day, the production rate will be associated with a flowing wellhead pressure of 100 psi (Pwellhead equals 100 psi). Your task is to determine the required specifications for the ESP for this application, assuming the minimum pump suction pressure is 200 psi (Psuction equals 200 psi).



$P_{suction} = 2823 - 0.433 \times 0.865 (1000 - 9800)$
$= 2748$ psia

Pump discharge pressure = 3728 psia || $P = h\rho g$ for simplification

Reqd. pump pressure $= P_{discharge} - P_{suction}$
$= 3728 - 2748 = 980$ psi.

Reqd pump head $= \frac{\Delta P}{0.433} = \frac{980}{0.433} = 2263$ ft of fresh water

Now, if one stage gives 60 ft head
No of stages require $= \frac{2263}{6} = 38$ stage

This problem is a straightforward formula-based exercise. Such problems can be helpful for practice and understanding the fundamentals of the subject. Similar problems may be given in an exam with some variations to assess your understanding.