Artificial Lift

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Lecture-47 ESP Numerical Problems-Part 2

Okay, every time I mention the API caching chart or tubing chart that you have to use, if you refer to the API document like 5CT, you will find a table with tubing nominal diameters listed, such as 2.38, 8.58, and many others. I've taken one example here, where the outer diameter is given in inches, and if you convert it to a fraction, you'll get the inner diameter size. For instance, several grades are available like J, C, and N grades, where 'N' signifies different material combinations. You should select your inside diameter based on your specific requirements, such as the presence of H_2S gas or high temperatures. 1.995 is commonly used, but you can choose other types of casing or tubing based on your needs. Classifications like A, B, C, D, J, C, N determine these choices.

Now, let's address another significant issue mentioned in Karmit Brown's book, 'Artificial Lift Technique: Technology for Artificial Lift.' The book specifies that the outer diameter of the casing is 8.58 inches, and the tubing size is 5.5 inches with a depth of 2200 feet. While the document doesn't explicitly mention the type of depth, let's assume it's a vertical wellbore. If it were a horizontal wellbore, you would need to provide the lengths of the vertical and horizontal sections. When calculating hydrostatic pressure, you would use the tubing's bottomhole pressure (TBD), while the friction pressure drop would consider the entire length of the pipe.

This represents the entire casing. The wellbore's depth is 2200 feet, with perforations made from 1900 to 2000 feet. The power source is primary, indicating the presence of a transformer with primary-side voltage at 12500 volts. As for the secondary voltage needs to be calculated based on requirements, including determining the number of turns. The fluid level is at 500 feet from the surface, with a water specific gravity (γ) of 1.1 and a wellbore temperature of 120 degrees Fahrenheit. Surface temperature isn't specified, so we assume it's the same as the wellbore temperature. The productivity index (J) is given as 10 barrels per day per foot of drawdown.

- Casing size: 8 $^5/_8$ in OD
- Tubing size: 5 ½ in OD, new.
- Depth: 2200 ft
- Perforation: 1900-2200 ft
- Power source: 12500 V primary
- Static fluid level: 500 ft from the surface
- Water sp gravity: 1.1
- Temp: 120 oF
- Productivity index: 10 b/d/ft of drawdown
- Surface flow line: 2000ft of 4 in with elevation of 30ft (all new pipes)
- Desired flow rate: 10000 b/d

- Select a suitable ESP and necessary equipment
- Determine well productivity capacity. In the problem a rate of 10000 b/d is desired.
- Determine total dynamic head in ft required for 10000 b/d

- Appendix 4C, friction.
- Page 336. Table 4G, casing size. For 8 5/8, ID=7.892.

Draw low $= \frac{q}{J} = \frac{10000}{10} = 1000$ ft

Lift head = 1000 ft draw down
+ 500 ft static head
= 1500 ft

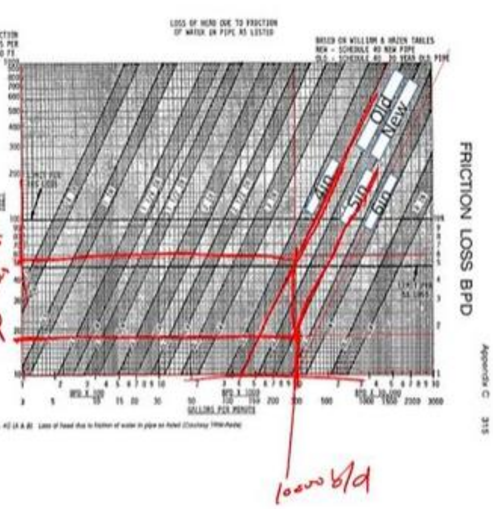
Set pump at 1600 ft ✓

Pwh = elevation + friction
$= 30 + \frac{55}{1000} \times 2000 = 140$ ft

$P_{fr\_tubing} = \left(\frac{18.5}{1000} \times 1600\right) = 29.6$ ft

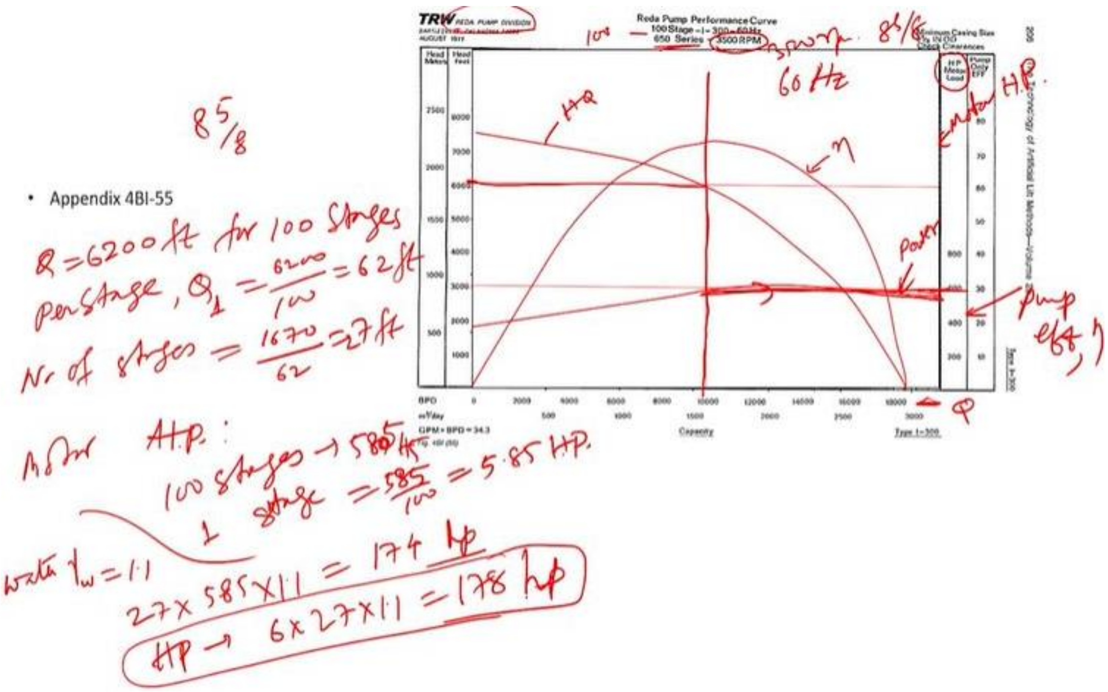
Total dyn head = lift + P_{fr_tubing} + P_{wh}
= 1500 + 29.6 + 140
= 1670 ft

friction pressure drop



Looking at the document again, you'll notice the use of 'B per day'; you can also use 'BBL per day'. A surface flow line extends 2000 feet from the wellhead, with a 4-inch diameter and an elevation of 30 feet. The desired flow rate is 10,000 barrels per day, and the flow rate from the wellbore to the surface will also be 10,000 barrels per day. Now, you need to select a suitable artificial lifting system, specifically an ESP system. To do this, you'll need to consider various parameters and use charts to calculate the appropriate ESP system for your wellbore.

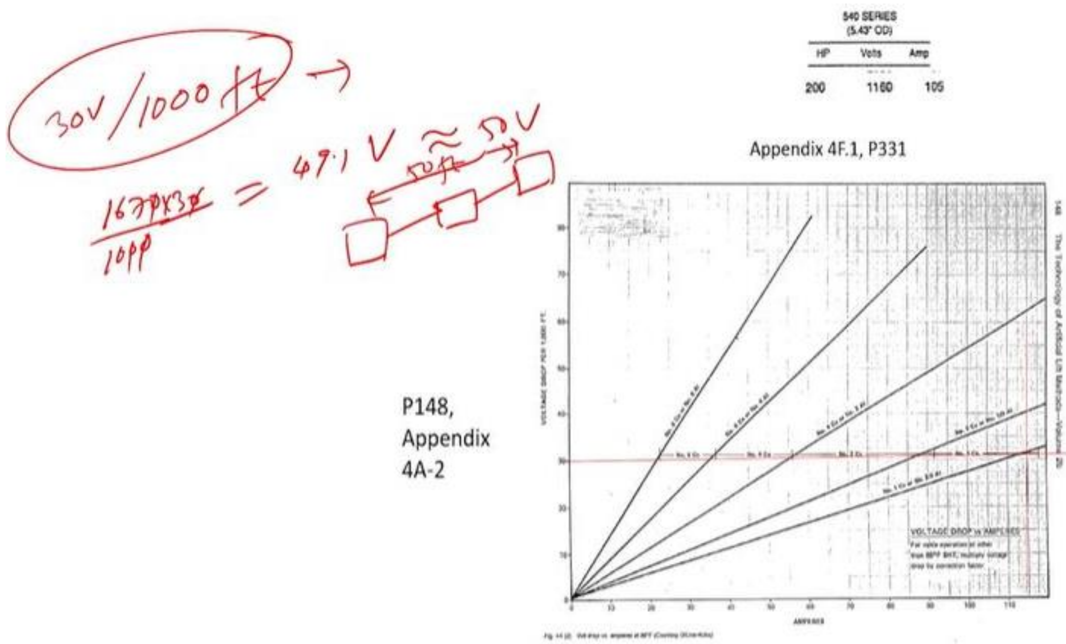
Let's start by calculating the drawdown, which you determine from Q divided by the productivity index (J). The flow rate is already provided as 10,000 barrels per day, and the productivity index is given as 10, resulting in a drawdown of 1000 feet. Now, for the lift head, which is the sum of the 10,000 feet of drawdown and the 500 feet of static head, you get a total of 1500 feet. This is the minimum depth at which the pump should be set to lift the fluid to the surface. To ensure a safety margin, you set the pump at 1600 feet. The reason for this margin is to account for any pressure variations.



However, you should know that wellhead pressure might be due to elevation components and piping friction. The elevation component is given as 30 feet. To determine the piping friction component, you'll need to refer to a table provided in Kermit Brown's book. This table uses flow rate (10,000 barrels per day) on the x-axis and pressure (friction or pressure drop) on the y-axis. The friction pressure drop can be obtained using this table.

And your surface piping is 4 inches. This 4-inch size represents the new pipeline mentioned in the problem. If we extend this pipe and move in this direction, it will reach 5.5 inches. So it's 5.5 inches per 1000 feet, and the total length of the surface pipeline is 2000 feet. This results in a 140 feet pressure drop on the surface wellhead due to the 4-inch pipe and a 30-foot elevation.

Now, let's consider the friction pressure drop in the tubing, denoted as P friction tubing. If we look at the 5-inch tubing depicted here, it's associated with a flow rate of 10,000. As we move in this direction, it increases to 18.5. So, 18.5 divided by 1000, multiplied by 1600. Why 1600? Because we've already set the pump at 1600 feet. This results in a friction loss of 29.6 feet for the new pipe. The friction value would be different if an old pipe were in use.



The total dynamic head can be calculated as follows: lift (1500 feet) plus tubing friction (29.6 feet) plus wellhead pressure (140 feet). So, the total dynamic head the pump should produce is 1670 feet.

To select a suitable pump, we need to refer to a table. The Reda pump company provides a chart for an 8 and 5/8 inch casing size. Let's go through the process for practice. This chart displays the pump curve, including the HQ (efficiency) and power curves.

You can see the specifications provided for an 8 and 5/8 inch tubing: it's a 100-stage pump, series 650, with an RPM of 3500. They assume 60 Hertz operation. However, the RPM is reduced by 100 due to loading, making it 3500 for the 60 Hertz pump. The X-axis shows the flow rate capacity; you have a flow rate of 10,000 barrels per day.

The 650 series pump covers a flow rate range of about 60 to 100. So, for our case with a flow rate of 10,000 barrels per day, each stage handles 60 to 100 feet of flow. That means you'll have a flow rate of 62 feet for each stage.

To determine the number of stages required for our case, we can divide the total depth of 1670 feet by 62 feet per stage, resulting in a minimum of 27 stages needed.

Normally, you should use more stages because there will be other losses that we haven't considered at this moment. For simplification purposes, we've done this calculation. Now, let's move on to motor horsepower. If we look at the same chart, this one right here, it's the motor horsepower chart. This chart also includes the pump efficiency curve or ETA and motor horsepower. As we move to the right, you can see that for 100 stages, it's approximately 585 horsepower (hp). So, for one stage, it's 585 divided by 100, which equals 5.85 hp.

However, in our case, the problem provides a water specific gravity of 1.1. Therefore, the horsepower requirement will be 27 stages multiplied by 5.85 per stage and then by 1.1. This results in 174 hp. We've also noted that the maximum head horsepower for this pump is 600. If you observe the horizontal line going to 600, it means approximately 6 horsepower per stage. If we use 6 horsepower per stage, the total horsepower required will be 6 multiplied by 27, and then by 1.1, resulting in 178 hp. So, we need to use 170 hp for the maximum power calculation. That's the required power. However, it's essential to calculate the maximum possible power, and based on that, you should choose your motor.

Regarding the cable, a thumb rule suggests a 30-volt drop per 1000 feet of cable length is acceptable. In this case, you need to calculate the total distance, including the motor distance and the surface cable. You must assess the voltage drop, which they assume to be approximately 1670 feet for the pump depth divided by 1000, and then multiplied by 30. This results in a voltage drop of about 50 volts through the cable. If you consider the surface cable, for example, it's about 50 feet. You should be aware that there will be a junction box, switches, and various control equipment at the wellhead. Therefore, the total voltage drop will be higher. You need to determine the voltage drop throughout the wellbore.

Now, Kermit Brown's book presents several problems. Students have suggested practicing problems similar to the one I'm currently working on. For instance, what happens if I switch to a different frequency, change the elevation, adjust the surface length, vary tubing or casing diameter, or alter the cable's voltage drop? You also need to calculate the transformer size. Furthermore, what happens if I modify the pump efficiency? These questions can be explored. I separately covered pump efficiency calculations in a previous lecture, but this problem integrates various aspects.

Now, let's integrate everything. The next consideration is when to use ESP and when not to use it. ESP is suitable for wellbores with deviations, whether they are curved, have a small or large radius, or are multilateral. ESP is versatile because it can pump in vertical or horizontal configurations. However, you must calculate frictional pressure drop and other pressure drops separately. It's generally acceptable to have around 10% to 15% gas. If you have more gas than that, ESP may struggle, even with a gas separator.

When it comes to sand, a small amount is manageable, but a significant amount of sand can erode the entire system. H2S gas presents another challenge. H2S is a highly corrosive gas, and when combined with sand, it can react with the metal surface, creating corrosive oxides, as discussed in a previous lecture. Metal oxides or metal sulfates can form, which are softer materials. Sand particles separately hitting the surface will remove this soft material, exposing the metal to hydrogen sulfide. This results in further corrosion and erosion, degrading the metal rapidly. Additionally, cavitation can occur, adding to the complexity of erosion, corrosion, and cavitation.

ESP can work at certain temperatures but has limitations due to elastomeric seals and electrical cables. Very high temperatures may pose difficulties unless a company has a proper downhole motor and cable insulation system. Normally, very high temperatures should be avoided. Regarding NPSH (Net Positive Suction Head), ESP requires the highest NPSH among all artificial lifting techniques. For example, PCP or Saccarot pumps need much less initial or suction pressure. ESP demands a high suction pressure.

ESP is suitable for offshore applications due to its compact surface unit and small requirements for control boxes, junction boxes, and transformers. In contrast, sucker rod pumps are typically avoided for offshore use due to their heavier units.

ESP is not suitable for handling very high viscosity fluids. Progressive cavity pumps are designed for high viscosity, but when viscosity varies significantly or very high viscosity fluids, such as thick grease or toothpaste, are involved, ESP is not effective. Emulsions can increase viscosity, creating challenges for ESP. Additionally, multiphase flow, including the presence of gas, can be problematic. While ESPs have gas separators, they have limitations in handling gas due to the risk of cavitation and other issues. Furthermore, issues such as vibration and cavitation in one stage of ESP can transfer to other connected stages.

If a problem arises in one stage, it can be transferred throughout the entire system, causing excessive vibration that may lead to failure. When considering artificial lifting selection techniques, a sucker rod pump is suitable for low flow rate applications, while ESP is designed for high flow rates. Sucker rod pumps typically have limitations for offshore applications, making them less commonly used. In contrast, ESP is a viable option for offshore and crooked well applications.

Gas is acceptable in small quantities, typically up to 10 percent. However, ESP may struggle with very high gas content. Sand and H2S are the primary challenges because in high-speed centrifugal pumps, sand particles impact the metal surface at a rapid rate, causing increased metal erosion. Additionally, emulsions can alter viscosity, affecting pump performance. If there is a change in fluid properties due to pressure or temperature changes, you must check for variations in viscosity.

Moreover, if the fluid changes from single to two phases before entering the pump, it can lead to complications. The fluid can be divided into two zones: a single-phase zone (Zone A) and a two-phase zone (Zone B). If the fluid becomes two-phase before entering the pump, gas separators can be used, but there is still a risk of gas entering the impeller. The first stage is particularly critical; it can lead to vibrations if it encounters gas. In subsequent stages, the pressure may gradually increase, which can help mitigate the issue and lead to a more stable mixture. However, the initial stages are more prone to problems if gas is present. This is the end of ESP system lecture. Thank you very much.