Artificial Lift

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Lecture-09 Nodal Analysis

In today's lecture, I will begin with Nodal Analysis. Nodal analysis involves understanding wellbore performance—how fluid flows from the reservoir to the wellbore and then to the surface separation system. To comprehend this concept, you should start by drawing the wellbore system. Imagine the wellbore consisting of tubing, a packer, and perforations. Perforations can be represented in various ways, but it's essential to maintain uniformity in your drawings.

Now, visualize the reservoir containing many connections, including liquids, sand, and fluids. Surrounding the reservoir is the casing. On the surface, the tubing extends, leading to the first control valve and then a choke that regulates the flow. After passing through the choke, the fluid flows slightly upward or downward before reaching the separator system. Gas and liquid components are separated in the separator, and finally, you arrive at the stock tank.

Wellbores can also be horizontal or slanted. For instance, a horizontal wellbore might appear as follows: it features packers, perforations, and a connection to the reservoir. I explained why vertical and horizontal wellbores are chosen based on pay zone thickness and width. In cases where the pay zone is relatively thin but extensive in width, a horizontal wellbore can connect to a larger area of the pay zone.

So, more fluid will enter your wellbore, increasing your productivity. That's why we opt for horizontal wellbores. However, for simplicity in our nodal analysis and other calculations, we assume that the wellbore is vertical or nearly vertical. If you delve into a detailed analysis of horizontal or multilateral wellbores, that would be a different course, specifically multilateral drilling and production.

In this course, I won't explore such complex situations in depth. When discussing nodal analysis, you need to consider nodes. A node typically represents the reservoir pressure, denoted as P_r, P_i, P_e, or P bar – all these notations have similar meanings. For our purposes, we assume this represents the reservoir pressure.

As fluid flows from the reservoir to your wellbore, you encounter P_{wfs}, P_{ws}, or P_{wfs} – often called the sand phase completion area – where resistance needs to be calculated. From there, the fluid enters your wellbore, and there's the Pwf, which stands for flowing pressure. It's essential to distinguish between the reservoir pressure and the flowing sand phase pressure or the pressure at the wellbore entrance.

Further along, an artificial lifting mechanism or some restrictions might lead to additional losses. This node could be labeled P-pump or another relevant term. It might involve an artificial lift system and another blocked area, often called a safety valve.

Why is a safety valve necessary? It is typically located below the surface. When producing oil and gas, unexpected events like earthquakes, terrorist attacks, or cyclones can damage the wellhead, leading to uncontrolled flow. In such cases, a subsurface safety valve, commonly called, comes into play.

This subsurface safety valve is connected to a pressure line that runs up to the wellhead and the Christmas tree. This small pipe controls the subsurface valve if the Christmas tree is somehow damaged or removed, causing uncontrolled flow. However, when this pressure pipe is severed, the pressure needed to control the valve is no longer maintained at the surface.

As a result, the valve automatically closes the flow path. This type of valve is known as a fail-safe valve. Why "fail-safe"? Because if something in the system fails, it ensures safety. To illustrate a similar concept in railway operations, consider train bogies connected end-to-end. If you were to disconnect one bogie, it would automatically reduce its velocity and eventually come to a stop.

If it is moving at a very high speed, it can be dangerous. This is what we call a fail-safe operation. If it is disconnected, the vacuum pressure will be released, and simultaneously, the brakes will be applied to the train's wheels, specifically the bogie wheels. As the brakes engage, the train will gradually come to a stop. Similarly, in our context, if something like a terrorist attack or a cyclone occurs, causing uncontrolled flow rates, cutting the pressure line will lead to a loss of pressure needed to control the safety valve. Consequently, the safety valve will close the flow path, stopping the flow. This is referred to as a fail-safe operation.

There will be one master control valve on the Christmas tree. As I mentioned, Christmas trees feature several valves, including lower and upper control valves. One of them will be automatic, and another will be manual. In this illustration, I'm showing only one control valve.

Now, let's talk about the choke. The control valve regulates your flow rate, enabling you to close, increase, or decrease the flow as needed. On the other hand, the choke's function is to reduce the flow.

So, wellhead pressure is one aspect, and your separator system pressure will be another. In between them, the choke will control the flow and provide the desired pressure and temperature to the separator system. When considering nodal analysis, you should consider everything as a node. For instance, the choke is a node, and the control valve is another node. You start by looking at areas where significant pressure losses occur. Other areas with pressure losses include the tubing, whether it's horizontal or slanted, and the separator system. Finally, you reach the conditions in your stock tank.

Stock tank conditions typically refer to 14.7 psi and 60 degrees Fahrenheit in standard conditions. However, in practice, you must maintain the conditions according to the temperature in your local atmosphere. For nodal analysis, you calculate pressure losses at different points in the production system.

As I mentioned, the wellbore is central to the overall production system. Here's a depiction of it: a wellbore with tubing, and there's a packer to consider because of the annular area. Speaking of the annular area, it's worth noting that sometimes it remains unused, while at other times, it's utilized for purposes such as gas injection or even some production.

The primary production will flow through your tubing, essentially a metal pipe. It features perforations like this. Since the tubing is cylindrical, there would be perforations all around, but in this two-dimensional representation, I'm only showing the left and right sides.

The fluid enters from the reservoir, which is the pay zone. The term "pay zone" refers to the area where the reservoir can be extensive. However, drilling a hole and extracting production from a specific zone is known as the pay zone because it generates income. Reservoirs don't have a strictly defined shape like a straight line or a rectangular or circular shape. They come in various random shapes. We often use approximations for our calculations, assuming shapes like rectangles or spheres, even though reservoirs can have interconnected pores extending across different areas.

Now, let's discuss Pr, which is reservoir pressure, as I mentioned earlier, and the wellhead.

All right, let's consider the wellhead. The wellhead often denoted as Pwh for wellhead pressure, involves many flow bends, turns, valves, and chokes. Consequently, there are significant pressure losses associated with the wellhead. When you have fluid flowing through pipes, there will always be losses. What do these losses entail? We'll delve into the details later, but I can provide an overview here.

Losses in pipes, or flow systems, essentially refer to pressure drops. When fluid flows through a pipe, a pressure drop occurs due to factors like friction or constricted passages. For example, when a choke is introduced, it creates a narrowed section, leading to pressure drop and friction losses. When using a sand control system, pressure drop can also occur in the sand phase completion area. A sand control system is designed to restrict the flow. While we aim to allow the flow of liquids and gases to increase productivity, some sand inevitably accompanies it, as we permit a certain amount of sand through tiny pores. Any restriction, such as bends in pipes, leads to pressure drop or loss.

If there is a sudden change in pipe dimensions, such as when a pipe initially runs horizontally and then suddenly increases or decreases in size, there will again be a pressure drop. Sudden changes in piping diameter, whether an increase or decrease, result in pressure drops. Pressure drops can also occur due to fittings like valves or joints. The flow surface may not be smooth in these cases, and protrusions or cavities can cause frictional pressure drops.

However, the most significant pressure drops occur in the sand control area or the connection between the reservoir and the wellbore. This connection, known as inflow performance, is where fluid flows from the reservoir into the wellbore. "P_{wf}" or flowing pressure is measured when the wellbore actively produces liquid, oil, or gas under flowing conditions. When we refer to flowing pressure, there is active production.

Conversely, if we stop production, the flowing pressure will reach zero. In cases with a substantial flow, the pressure difference between reservoir and flowing pressure will be significant. However, there will be no flow if the flowing pressure is nearly equal to the reservoir pressure. This is because a pressure difference is required to move fluid particles from one point to another. Without a pressure difference, there will be no flow.

So, if we assume Pwf and flow rate, the reservoir pressure is initially very high. However, when your flowing pressure or wellbore is not producing, there is no flow when your valve closes the flow path. In that case, what happens is that P_r (reservoir pressure) and Pwf (flowing pressure) are almost equal. When P_r and P_{wf} are practically similar, the flow rate will be nearly 0.

So, in certain situations, if P_{wf} is 0, meaning the wellbore pressure is almost or entirely 0, then P_r minus P_{wf} is very high. P_r minus P_{wf} is exceptionally high. Consequently, if it's very high, your flow rate will also be very high. When the wellbore's flowing pressure is 0, you get a very high flow rate because of the significant difference between P_r and P_{wf}. However, if the opposite is happening, if P_{wf} is 0, the flow rate is high. But if P_{wf} is very high and nearly equal to P_r, then in that case, you get Q=0.

The curve representing this relationship typically looks like this. Now, if I calculate the slope of this curve, the inverse of the slope is called the productivity index, denoted as J. This curve is commonly referred to as the Inflow Performance Relationship or IPR.

In terms of the IPR, if I plot this on the x-axis and y-axis, the tangent of the angle theta equals 1 divided by J, which equals (P_r minus P_{wf}) divided by Q. Thus, J is equal to Q divided by (P_r minus P_{wf}), and J is referred to as the productivity index.

$$tan\theta = \frac{1}{J} = \frac{(P_R - P_{wf})}{Q}$$

$$J = \frac{Q}{(P_R - P_{wf})}$$

Now, let's discuss outflow performance. What is outflow? It refers to when fluid, oil, or gas enters the reservoir and flows from the reservoir to the surface separation system. This is termed outflow performance. Although we've defined upstream and downstream in the context of oil and gas, we use upstream and downstream slightly differently for specific nodal analysis. For example, I want the choke here. So, for the choke, this is the upstream and the downstream. Okay, this is upstream, and this is downstream. If the choke is my node, then upstream of the choke means before the choke where the fluid is coming from, which is considered upstream. After the choke, where the fluid is going is called downstream. Now, let's discuss the main elements of nodal analysis.

So, first, I will draw the exact figure again quickly. I have a packer, and I have tubing. Okay, from the tubing, my fluid is going like this. I have the choke here and assume there is no valve now. Then it goes to the separator. It goes there, gas goes to the compressor, and I store it in a stock tank. Gas is going to the compressor, and the liquid is stored in the stock tank again. Now, the main point is that the reservoir will be like this.

So, the reservoir P_R (reservoir pressure) is where we can start. 1A, this is 1, 1. This separator system is 1, then there is 2, then the wellhead is 3, then there will be another valve arrangement, this is 4. There may be one pump here, 5 pumps, or an artificial lift, and we call it an artificial lift. This is called a pump. Then, there will be Reservoir Connectivity 6, the Sand Phase Completion 7, and the Reservoir Area 8. These are key points for nodal analysis because we must find where the pressure drop is happening and where the maximum pressure drop occurs. We need to determine if we can calculate it separately.

Again, when calculating the pressure drop, we must consider it from the reservoir to the separator system.

We cannot analyze these separately. For example, when we calculate the inflow performance relationship, at the same time, we have to calculate the outflow performance relationship as well because everything is linked. We cannot calculate the inflow separately and then calculate the outflow separately. If there is a mismatch between flow rate, pressure, and temperature, the entire system can get disturbed, and production may be hampered.

So, your pressure drop is like this: if we have PR (reservoir pressure) and Pwfs (flowing pressure), then many other pressures, such as P, P_4, P-pump, P-safety valve, P-wellhead (P_{wh}), P choke, P separator, and so on. The pressure drop, ΔP, can be represented as

$\Delta P_1 = (P_s - P_{ch})$,

where P_s is higher than P_{ch}.

Similarly,

$\Delta P_2 = (P_{ch} - P_s)$.

We can calculate all the pressures this way and understand how the pressure varies from the reservoir to the surface.

So, first, we have the reservoir, then the tubing, and I'm showing the major losses here: flowline and transfer line. The reservoir pressure is initially very high, P_R or P_e, and there will be certain losses through porous media. When it enters the wellbore, there will be some pressure drop. From the wellbore, there will be a pressure drop in the tubing. When it reaches the wellhead, there will be another pressure drop. In the flowline, an additional pressure drop will continue until it reaches its final destination.

P represents the stock tank, which is the reservoir pressure, Pwf. Here, we have Pwh, the wellhead pressure, and then P separator, or I can call it choke pressure. This is how the pressure decreases along the path. To reach the stock tank, we need to identify where the maximum pressure loss occurs and consider how to mitigate it during the design and selection stages of the entire system.

Now, we've looked at the IPR curve like this. Initially, we assume this is single-phase flow or single-phase liquid flow. In single-phase liquid flow, there is no phase change from the reservoir to the wellhead, let's take. The flow looks like this, with Q here and Q_{max}, which is P_{wf} and P reservoir. Sometimes, people use different notations like P_R, P-$_{bar}$, P_e, P_i, and Q and may write small q.

Whenever you use these notations, you should clearly explain their meanings and purposes. For example, if you're using PR for reservoir pressure, write "reservoir pressure equals PR." Also, remember to specify the units you are using. While SI units are acceptable, I recommend using field units because it's essential to be familiar with them when interacting with other industry professionals in the oil industry.

Some might find it confusing if you mention density in terms of kilograms per cubic meter. However, using API is more straightforward because people in the industry are familiar with this unit. Additionally, in this field, we often use various notations differently. For instance, when talking about production in barrels, we might write it as BPD (barrels per day), BOPD (barrels of oil per day), BWPD (barrels of water per day), BBLPD (barrels per day), BBL/D (barrels per day), BD (barrels per day), or STBPD (stock tank barrels per day). We express this in several ways, so when you see BBLPD or BOPD, you should assume it refers to barrels per day. If it's not per day, then it should specify whether it's per hour, minute, or second. However, the standard notation for flow rate is barrels per day.

We've discussed inflow performance, and there will also be outflow performance. I will detail inflow performance in the following lecture, and subsequent lectures will cover outflow performance. If we have a two-phase flow instead of a single-phase, the curve will not be a straight line; it might look more like this or even like this.

So, there will be different relationships that I will discuss later. That discussion will come later for outflow performance, whether it involves multi-phase flow or single-phase flow with a choke. This represents our production area. Remember that this production area doesn't necessarily imply optimal; it shows that production is happening consistently from the reservoir to the stock tank without issues. However, if you deviate from this point, problems may arise because you might try to produce a very high amount of fluid, but other systems are not properly matched. In such cases, your entire system could become disrupted, and you may not achieve the desired production.

Now, let's talk about Qmax. I've mentioned that, ideally, we assume the flowing pressure is 0. In an ideal scenario, this would result in very high production. Outflow performance is sometimes referred to as vertical lift performance (VLP). Don't be confused if you come across different terms; it's essentially the same concept. So, whether we discuss nodal analysis, IPR, or VLP, it's crucial to consider factors like pressure, temperature, single-phase flow, and multi-phase flow. This is why I emphasized understanding reservoir flow properties and fluid properties, including units.

It would help if you correlated reservoir pressure with the fluid inflow. Considerations like gas generation, sand content, and pressure drop should be addressed if a substantial amount of fluid is coming in and you're implementing artificial lift. For instance, using a pump could lead to issues like cavitation. A grasp of IPR, VLP, or outflow performance relationships will enable you to select the appropriate artificial lift systems for your wellbore.