Artificial Lift

Prof.Abdus Samad

Department of Ocean Engineering

Indian Institute of Technology Madras, Chennai

Lecture-45 ESP Numerical Problems-Part 3

During my teaching on emulsions, we discussed phase inversion. Phase inversion occurs when you take a certain amount of oil and add water. The water cut measures the water content in the mixture, where 0% water cut means there's no water (only oil), and 100% water cut means there's no oil (only water). When you add water to oil, the viscosity increases steadily. The viscosity peaks after reaching around 60% to 70% water cut, and then there's a sudden drop.

Before phase inversion, there's a small amount of water in the oil, resulting in a water-in-oil emulsion, with water droplets suspended in the oil. After phase inversion, the water content increases, and the oil becomes dispersed as small particles in a continuous water phase, creating an oil-in-water emulsion.

One of my PhD students, Billery, conducted experiments with emulsions at different water cuts. He prepared stable emulsions with varying water content and then investigated the impact of these emulsions on centrifugal pumps. The figure in the top right corner shows that phase inversion typically occurs around 60% water cut. During phase inversion, there's a significant increase in viscosity, followed by a decrease.

Increased viscosity can impede fluid flow through the impeller channel in the pump. Particles in the fluid experience resistance due to high viscosity, causing them to pull back and stick to the surface, which hinders fluid movement. As a result, the pump's head, efficiency, and flow rate decrease when viscosity is high.

Bellary tested different water cut conditions to observe their effects on pump head. Higher water cut generally led to increased head, but the head was lower when mixing in between 100% water and 0% water. Emulsions in the wellbore can change pump performance, especially when water content fluctuates. If you're not aware of this physical phenomenon, it can be confusing when your pump's performance changes over time.

Next, we'll explore the multiphase effects.

The left picture illustrates a multiphase centrifugal impeller diffuser called a multiphase Electric Submersible Pump (ESP). This work was done by one of my Master's (MS) students, Raheet Adal, and published in a journal paper. The diagram shows an impeller with an eye where fluid enters, followed by a diffuser, and the flow direction. This is considered a mixed flow design due to the approximately 45-degree angle of the impeller blades. The diffuser's role is to guide the flow further. The entire sequence continues through multiple stages stacked one after the other.

The right-side picture is also from the same paper, illustrating an impeller (impeller A) with its entry and exit points for fluid. Like the left picture, fluid enters the impeller and proceeds through the diffuser. This sequence is repeated for multiple stages.

The pressure in these diagrams is indicated by color, with lower pressure at the inlet and higher pressure as the fluid progresses. The diffuser section appears completely black, indicating pressure development, but lower velocity. Inside the impeller, velocity head is higher than pressure head, leading to the observed pressure distribution.

Multiphase performance data from Rohit Otto's research using computational fluid dynamics (CFD) is also included, covering different gas volume fractions. The experiments involved up to 10% gas volume. Simulating multiphase flow through CFD or experimentation is complex due to particle distribution and size. Real-world flows are intricate, with particles breaking apart or merging, which can lead to loss phenomena. This complexity makes simulating multiphase flows through turbomachinery or pumping systems challenging.

The graph on the right shows the relationship between gas volume and power input for various gas volume fractions, with the lines indicating different designs and optimizations. Interestingly, higher gas volume tends to reduce power input.

In the text, the explanation continues with a description of the impeller's geometry, including the suction side and pressure side. It mentions that due to the density difference between gas and liquid, gas particles may separate or segregate from the liquid during the flow. This segregation is influenced by the drag action of the fluid and the differing densities of the gas and liquid phases.

This was reported in the paper. In a centrifugal pump or ESP system, you have a casing, followed by tubing, a motor, a protector, a pump intake, and the pump itself. The typical sequence has the motor at the bottom, followed by the protector section, the pump intake, and then the pump. A shaft extends from the motor to the pump, which is usually not a single shaft but rather a series of connected shafts designed to transfer torque without axial, radial, or vibrational forces.

You should use an integral intake when handling up to 10 percent gas volume in the wellbore. If there is no gas, an assembly system without gas is suitable. However, if there is gas, using a gas separator at the pump intake is crucial. The entire system includes a gas separator, NPSH enhancer (or inducer), and a coupling.

The coupling can be of various types, such as spline, flexible, and others. Depending on the design, the shaft extends through the intake section, which can be rotary or static. In the case of a reverse flow type intake, liquid and gas are separated with liquid directed toward the pump's impeller eye. In contrast, a rotary gas separator uses a shaft connected to the protector, which is then linked to the gas separator or intersection shaft. This intersection shaft typically contains an inducer to provide the necessary NPSH (Net Positive Suction Head).

Sometimes, actual centrifugal pumps may require a very high amount of NPSH, such as 75 PSI.

The wellbore may not support such high-pressure requirements in certain wellbore conditions. An axial pump, specifically an inducer, is used in such cases. The axial pump provides a certain amount of pressure and a high flow rate, serving as a helper to the main pump rather than directly providing head. Fluid enters the inducer through a screen and goes through its multiphase flow process. A typical inducer has about five blades.

A gas separator is essential when dealing with significant pre-gas or gas within the fluid mixture. The gas separator uses centrifugal action to separate gas from the liquid. Due to centrifugal forces, gas particles with lower density remain closer to the center, while liquid takes the outer space.

The vortex-type separator ensures that gas does not touch the outer wall, preventing it from moving to the liquid's path. Liquid enters the pump's intake or impeller eye, and gas is discharged from the system. This separation process efficiently manages multiphase flows.

The use of an inducer is not to provide a significant head to supply water or oil to the surface but to increase the Net Positive Suction Head (NPSH) of the main pump. An inducer helps the main pump by receiving enough inlet pressure to prevent cavitation, vibration, and pump failure. While the main pump is the primary component, the inducer acts as a helper to enhance its performance.

In a situation with high energy losses within the pump, the pump's temperature may rise. Fluid flow can help dissipate heat generated within the pump, but the extent of heat removal depends on the fluid flow rate and its heat capacity. Water has a high heat capacity, making it suitable for pumping applications. However, heat generation can lead to material and other issues when pumping oil with a lower heat capacity.

To calculate the temperature rise of the fluid, you can use the following formula:

ΔTf equals $H(1-\eta p)$ divided by 778 $C\eta p$

Where:

- ΔTf is the temperature rise of the fluid.
- H represents head.
- ηp is the pump efficiency.
- 778 is a constant.
- C is the heat capacity of the fluid.

The specific heat of water and oil is used to calculate the temperature rise. For water, with a 7000 feet head and a pump efficiency (ηp) of 64 percent, the temperature rise (ΔTw) is 5 degrees Fahrenheit. For oil, the temperature rise ($\Delta Toil$) is 10 degrees Fahrenheit due to the lower heat capacity compared to water.

ΔT_x

Determine ΔT to pump
(a) Water (c =1 BTU/lb/F) and
(b) (b) oil (c = 0.5 BTU/lb/F). The pump develops 7,000 ft head
and η_p=64%.

$$\Delta T_w = \frac{H(1-\eta_p)}{778 c \eta_p} = \frac{7000(1-0.64)}{778 \times 1 \times 0.64}$$

$$= 5^\circ F$$

$$\Delta T_o = \frac{H(1-\eta_p)}{778 c \eta_p} = 10^\circ F$$

This difference in temperature rise is due to the heat capacity of the fluids; water, with its higher heat capacity, experiences a lower temperature rise compared to oil. Thank you very much.