Surface Facilities for Oil and Gas Handling

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Introduction To Separator-02

Stage separation is a critical process in oil and gas operations, involving the use of different types of separators such as horizontal, vertical, and spherical. When dealing with very high-pressure gas, a single-stage separation may be challenging and uncontrollable. To address this, multiple stages are created to gradually separate components and reduce pressure in a controlled manner.

The approach involves step-by-step separation. Initially, a two-phase separator is used to separate liquid and gas components. The pressure is then reduced, leading to a three-phase separator, where oil, water, and gas are further separated. This process, known as stage separation, enables efficient and controlled separation of components.

The stages are denoted as the first stage, second stage, and so on. Each stage contributes to the overall separation efficiency. The fluid enters the system from the wellhead (WH), but it typically doesn't directly reach the separator. Instead, there is a choke section that directs the fluid to the initial stages of separation.

This staged separation allows for a more manageable and controlled process. Attempting to separate everything in a single stage would result in an oversized and uncontrollable system. By breaking down the separation into stages, engineers and operators can achieve better control over the process, ensuring efficient separation of oil, water, and gas components.

The process continues as the well fluid, comprising oil and gas, is directed through a choke. This choke serves to control the flow of oil and gas into the initial stage of the separation process. In scenarios where there are multiple wellheads or multiple wellboards, they can be connected to a manifold, commonly referred to as a choke manifold.

The choke manifold facilitates the mixing of fluids from various sources, directing them toward the separators. Fluids then pass through separator stages labeled 1, 2, 3, and 4, indicating the sequential separation process. Each stage contributes to the gradual removal of oil, water, and gas components.

The pressures at each stage differ, with the first stage having a considerably high pressure, for instance, around 1200 psi. Subsequent stages, such as the second stage, may see a pressure reduction, perhaps to 500 psi, and this trend continues until the final stage where the pressure reaches approximately 14.7 psi.

Once the fluid has undergone the entire separation process, it enters the stock tank. In the stock tank, all volatile components are removed, resulting in what is referred to as dead oil. Dead oil is oil devoid of volatile components, and its condition is maintained at atmospheric pressure. Conversely, live oil represents the fluid obtained directly from the wellbore, maintaining the same pressure and temperature conditions as the reservoir.
The pressure at each stage in the separation process is determined by the ratio of the first stage pressure (P1) to the stock tank pressure (P stock tank), using the formula:

$$R_p = \left(\frac{P1}{P_s}\right)^{\frac{1}{(N_{st}-1)}}$$

Here, N_{st} represents the number of stages.

In your example, you've mentioned that there are 4 stages ($N_{st} = 4$). Therefore, substituting this into the formula, we have:

$$R_p = \left(\frac{P1}{P_s}\right)^{\frac{1}{(4-1)}}$$

$$R_p = \left(\frac{P1}{P_s}\right)^{\frac{1}{3}}$$

You mentioned an approximate pressure ratio of 3 for the given situation. Now, if you want to calculate the intermediate pressure (P2), you can use the following formula:

$$P_2 = \frac{P_{i-1}}{R_p}$$

Substitute P_{i-1} with the previous stage pressure (P1 in the first stage) to find the intermediate pressure for each stage. Repeat this process for subsequent stages.
Let's solve the example problem and calculate the pressure at intermediate stages for the surface separated system.

Given data:

- Initial separator pressure (P1) = 1200 psi

- Stock tank pressure (P_stock tank) = 14.7 psi (assuming standard atmospheric pressure)

The pressure ratio (R_p) is given by the formula and in this case, you've mentioned an approximate value of 3 for R_p.

Now, let's calculate the intermediate pressures using the formula; $P_2 = \frac{P_{i-1}}{R_p}$

1. First Stage (P1): Given as 1200 psi.

2. Intermediate Pressure at Stage 2 (P2):

$P_2 = \frac{P_1}{R_p}$ =1200/3= 400 psi

3. Intermediate Pressure at Stage 3 (P3):

$P_3 = \frac{P_2}{R_p}$ =1200/3= 400 psi

4. Intermediate Pressure at Stage 4 (P4):

$P_3 = \frac{P_2}{R_p}$ =1200/3= 400 psi

5. Stock Tank Pressure (Ps): Given as 14.7 psi.

Now, you have the intermediate pressures at each stage (P2, P3, and P4), and the stock tank pressure. These values give you an understanding of the pressure conditions at different points in the separation process.

Let's go through the calculations step by step:

Given data:

P1 (First stage pressure) = 1200 psi

P_s (Stock tank pressure) = 14.7 psi (standard atmospheric pressure)

N_st (Number of stages) = 4 (you've mentioned 4 stages)

Calculations:

1. Calculate Rp (Pressure ratio):

$$R_p = \left(\frac{P1}{P_s}\right)^{\frac{1}{(N_{st}-1)}}$$

$$R_p = \left(\frac{1200}{14.7}\right)^{\frac{1}{(4-1)}}$$

$$R_p = 27.21$$

2. Calculate intermediate pressure at Stage 2 (P2):

$$P_2 = \frac{P_1}{R_p}$$

$P_2 = \frac{1200}{27.21}$=44.11 psi

3. Calculate intermediate pressure at Stage 3 (P3):

$P_3 = \frac{P_2}{R_p}=\frac{44.11}{27.21}$=1.62 psi

4. Calculate intermediate pressure at Stage 4 (P4):

$P_4 = \frac{P_3}{R_p} = \frac{1.62}{27.21} = 0.059$ psi

So, the intermediate pressures are approximately:

P2 ≈ 44.11 psi

P3 ≈ 1.62 psi

P4 ≈ 0.059 psi

These values represent the pressure at each intermediate stage in the surface-separated system for oil and gas.
let's discuss the analysis of the problem:

1. Given Data:

Inlet Pressure (P1) = 276 psi (as calculated in the previous step)

Atmospheric Pressure (P_s) = 14.7 psi

2. Calculate Rp (Pressure Ratio):

$$R_p = \left(\frac{P1}{P_s}\right)^{\frac{1}{(N_{st}-1)}}$$

$$R_p = \left(\frac{276}{14.7}\right)^{\frac{1}{3-1}}$$

$$R_p = 9.42$$

3. Calculate Intermediate Pressure at Stage 2 (P2):

$$P_2 = \frac{P_1}{R_p}$$

$P_2 = \frac{276}{9.42} = 29.28$ psi

4. Calculate Intermediate Pressure at Stage 3 (P3):

$$P_3 = \frac{P_2}{R_p}$$

$P_3 = \frac{29.28}{9.42}$=3.10 psi

5. Calculate Intermediate Pressure at Stage 4 (P4):

$$P_3 = \frac{P_2}{R_p}$$

$P_3 = \frac{3.10}{9.42}$=0.33 psi

6. Determine the Optimal Number of Stages:

Given the pressure range of 3.6 to 4 as optimal, we can observe that the calculated Rp falls within this range (9.42).

This suggests that the number of stages (Nst) should be less than 2.

7. Conclusion:

Based on the high pressure conditions (P1 = 276 psi), it's advisable to have fewer stages, likely less than 2, as a very high number of stages may not be optimal for the system.

Keep in mind that this is a simplified analysis, and actual system design considerations may involve additional factors.
Let's break down the different terms and types of separators used in the oil and gas industry:

1. Separator:

Commonly referred to as a conventional oil and gas separator.

It separates well work fluid into different phases, typically gas and liquid.

2. Knockout Vessel / Drum Trap:

Removes water from well work fluid.

Liquid knockout is more specific and removes all liquids, including oil and water.

3. Flash Chamber or Trap Vessel:

Utilized in conventional low-pressure separators.

"P" denotes pressure.

4. Expansion Vessel:

Used in the first stage of the separator, especially in low-temperature or cold separation units.

5. Gas Scrubber:

Similar to an oil and gas separator.

Handles a smaller amount of liquid loss compared to separators in oil and gas wells.

6. Filter Gas Filter Separator / Dry Gas Scrubber:

Additional terms used in the context of gas filtration and separation.

7. Terms and Fluid Implications:

Well work fluid encompasses various substances, including crude oil, condensate, natural gas, free gas, solution gas, water, and impurities (which may include sand).

Crude oil is characterized by its color, ranging from yellowish to black or shades of green.

API gravity is used to measure the density of crude oil.

8. Viscosity of Crude Oil:

The viscosity of crude oil, denoted by "C P," ranges from 5 to 90,000 centipoise (C P).

Emphasized the correct notation of "C P" (capital C and capital P).

9. Note on Terminology:

Different terms such as knockout vessel, drum trap, liquid knockout, flash chamber, and gas scrubber are used interchangeably based on specific functionalities.

Understanding these terms is crucial for anyone working in or studying the oil and gas industry, as they form the foundation for discussions related to separators and well work fluid.

Let's summarize the below terms related to the above discussion;

1. Condensate:

May exist in producing formations either as a liquid or a condensable vapor.

API gravity for condensate ranges from 50 to 120 degrees API.

Viscosity is denoted as "C P" and specified within the range of 226.

2. Natural Gas:

Described as a substance with no shape or volume, filling any container.

Essentially free gas, sometimes referred to as natural gas.

Viscosity specific gravity varies from 0.55 to 0.90 relative to air.

Viscosity of natural gas is within the range of 0.01 to 0.024 C P.

3. Solution Gas:

Obtained when reducing pressure, and the gas goes out.

Predominantly consists of water.

4.Handling Water:

Emphasized the importance of handling water, considering its viscosity and gravity.

5. Pressure and Temperature Classification:

Illustrated a typical pressure and temperature classification for separators.

High-pressure separators have around 1500 psi, intermediate-pressure separators have about 750 psi, and low-pressure separators operate at approximately 250 psi.

Temperature ranges from minus 35 degrees Fahrenheit to plus 200 degrees Fahrenheit, denoting lower temperature (L T) and higher temperature (H T).

Understanding these parameters is vital in the context of separator design and operation in the oil and gas industry. The provided ranges offer a rough estimate of pressure and temperature conditions in different types of separators.

1. Importance of Parameters:

Understanding the discussed parameters is crucial for designing and operating separators in the oil and gas industry.

2. Pressure and Temperature Definitions:

High Pressure (H P) corresponds to the specified high-pressure conditions.

Intermediate Pressure relates to the intermediate pressure conditions.

Low Pressure (L P) is associated with low-pressure conditions.

Low Temperature (L T) refers to the specified low-temperature conditions.

High Temperature (H T) indicates high-temperature conditions.

3.Pressure Definitions:

PSIG (P S I G):Gauge pressure, measured using a gauge showing pressure.

PSIA (P S I A): Absolute pressure, where atmospheric pressure is considered 1 bar.

Relative Pressure: It is expressed as 0 relative to atmospheric pressure.

These definitions provide clarity on pressure and temperature conditions in different types of separators, aiding students in avoiding confusion when dealing with various terms and units.

Clarifications on units and terms:

1. Pressure Units:

PSIG (PSI Gauge): Gauge pressure measured using a gauge. The relationship is PSIA = PSIG + 14.7 PSI.

2. Gas Volume Units:

MMACF:Million standard cubic feet. It's important to note that 'MM' denotes million.

If the notation is single 'm,' it typically signifies milli (e.g., millimeters).

If the notation is 'M' (capitalized), it generally represents mega (e.g., million).

3. Temperature and Standard Cubic Feet:

Standard conditions for gas are 14.7 PSI and 60 degrees Fahrenheit. This is the basis for calculating standard cubic feet.

Understanding these units and terms is essential for accurate measurements and calculations in the oil and gas industry.

There are hree types of separator systems commonly used in the oil and gas industry:

1. Horizontal Separator:

Fluid entry: Well head

Characteristics: Horizontal orientation

Design consideration: Diameter to length ratio

If the length is more than the diameter, it is effective for separating gas and liquid components.

2. Vertical Separator:

Fluid entry: Well head

Characteristics: Vertical orientation

Design consideration: Can have 2 or 3 layers for separating gas and liquid components.

3.Spherical Separator:

Fluid entry: Well head

Characteristics: Spherical or bean shape

Design consideration: Compact space, often used in offshore applications where space is limited.

These separators play a crucial role in the oil and gas production process, allowing for the separation of different components (gas, liquid, and sometimes solid impurities) for further processing and utilization. The choice of separator type depends on factors such as pressure, volume, and space constraints.

In a two-phase separator, the primary separation is between gas and liquid components. In a vertical separator, there is flexibility to create either two or three layers for the separation process. Here are the details for each type of separator mentioned:

1. Vertical Separator (Two Layers):

Fluid Entry:Wellhead

Characteristics: Vertical orientation

Design Consideration:Typically, two layers for separating gas and liquid components.

2. Vertical Separator (Three Layers):

Fluid Entry: Wellhead

Characteristics: Vertical orientation

Design Consideration: Can be designed with three layers for more refined separation, possibly for gas, oil, and water.

3. Spherical Separator:

Fluid Entry: Wellhead

Characteristics: Spherical or bean shape

Design Consideration: Compact shape, often used in offshore applications where space is limited. Gas and liquid components get separated in a spherical geometry.

Each type of separator serves a specific purpose in the oil and gas separation process, offering solutions based on factors such as space availability, efficiency, and the need for multi-phase separation.
It's clear that there are several types of separators used in the oil and gas industry, each tailored to specific conditions and requirements. The choice between horizontal, vertical, or spherical separators depends on factors like pressure, space constraints (as in offshore applications), and the need for two or three-phase separation.

Additionally, your mention of water knockout drums and other specialized separators highlights the complexity of the separation process and the need for specific equipment tailored to handle different components within the wellhead fluid.

Understanding the piping and instrumentation diagram (P&ID) and process flow diagram (PFD) is crucial for comprehending how fluids move through the separator system. While a PFD provides a simplified view of the overall process flow without scaling, a P&ID delves into more details, including instrumentation, valves, equipment sizes, insulation, and various parameters. It's an essential tool for engineers and operators to understand and maintain the functionality of the separation system.
The importance of understanding PFDs and P&IDs in the context of separator systems. It's indeed crucial for anyone in the oil and gas industry to be familiar with the symbols

used in these diagrams, as they convey vital information about the equipment, valves, and processes involved.

Symbols play a significant role in simplifying the representation of complex systems, making it easier for engineers, operators, and other stakeholders to interpret and work with these diagrams effectively. Your guidance on focusing on the essential symbols for the class while acknowledging the existence of more comprehensive symbol sets aligns well with the practical approach to learning and applying this knowledge.

If there are specific symbols or concepts you'd like further clarification on or if there's a particular aspect you'd like to discuss next, feel free to let me know!

Then air cooler is there then control valve will be there. So, some control mechanism will be there you can control from top shut down valve continuously creates shut down this is called choke valve . So, choke is there. So, you can create symbol like this LC level controller, PC pressure controller, TC temperature controller and M or FQ these are called flow meter flow meter . And this is called process vacuum valve, this is called flame arrestor.

This is called compressor. So, compressor actually they have done something wrong. You want to leave then you leave I will complete this one then next day we will continue in the next.