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Exploring the Advancement in Computational Mathematical Analysis for Upstream and Midstream Application of Centrifugal Compression

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Abstract

Centrifugal compressors play vital role in many compression applications across various industries. This work reviewed applications of centrifugal compressors in upstream and midstream sectors especially compression, refrigeration, pipeline compression, gas injection, gas lift, gas gathering, export compression and air compression. In LNG compression, centrifugal compressors are instrumental in ensuring efficient and reliable compression of liquefied natural gas, enabling its safe transportation and storage. Compressors offer exceptional cooling capabilities in refrigeration processes, enabling preservation of perishable goods and maintaining optimal temperatures in various industries. Pipeline compression is a function of centrifugal compressors, it facilitates movement of natural gas through vast networks of pipelines, ensuring constant and uninterrupted supply to consumers. Gas lift operations in oil production enhance well productivity where centrifugal compressors provide necessary pressure to lift oil to the surface. Similarly, in gas gathering systems, compressors aid in collecting and transporting gas from multiple wells to processing facilities. Centrifugal compressors are also utilized in export compression to compress natural gas for international transportation, enabling countries exporting their valuable energy resources to global markets. This research provides comprehensive insights into diverse applications of centrifugal compressors in upstream and midstream sectors with emphasis on compressor design, its performance characteristics and control.

Keyword: Upstream, Midstream, Application, Centrifugal, Compression.

Introduction

n recent years, there has been a significant advancement in computational mathematical analysis techniques for studying the behavior and performance of centrifugal compression systems in both upstream and midstream applications in the oil and gas industry. These advancements have revolutionized the way we understand and optimize the design, operation, and efficiency of centrifugal compressors, which are crucial for various processes involved in the extraction, transportation, and processing of natural gas.The computational analysis of centrifugal compression systems in upstream applications has garnered considerable attention (Smith & Johnson, 2016) due to its potential to enhance the efficiency and reliability of compression processes. Researchers have utilized mathematical modeling approaches to simulate and analyze the flow characteristics, impeller design (Garcia et al., 2022), surge control strategies (Johnson et al., 2019), and impeller erosion and wear (Patel et al., 2022) in these systems. These studies have shed light on optimizing the performance parameters (Patel & Roberts, 2018) and exploring the impact of gas composition (Chen & Wang, 2023) on centrifugal compressor efficiency in upstream operations.Similarly, in midstream applications, computational techniques have been applied to model and analyze centrifugal compressors used in gas transportation. Mathematical modeling and simulations have been employed to examine surge dynamics (Thompson & Wilson, 2022), impeller design (Lewis et al., 2021), and flow instability mechanisms (Lewis et al., 2023). These studies have contributed to the optimization of design (Zhang et al., 2023) and the development of surge control strategies (Johnson et al., 2023) for enhanced performance and reliability of centrifugal compressors in midstream applications.Moreover, the use of advanced computational fluid dynamics (CFD) simulation techniques (Garcia et al., 2018) has allowed for a deeper understanding of flow characteristics (Zhang et al., 2019) and flow instabilities (Garcia et al., 2022) in centrifugal compressors, enabling engineers and researchers to make informed decisions regarding system design and operational strategies. Additionally, optimization algorithms and numerical methods have been employed to improve the efficiency and overall performance of centrifugal compressors (Chen & Wang, 2020.) the advancement in computational mathematical analysis for upstream and midstream applications of centrifugal compression has enabled a comprehensive exploration of various aspects, including flow characteristics, impeller design, surge control, impeller erosion, and wear. The integration of advanced computational techniques with mathematical modeling has facilitated the optimization of centrifugal compressor performance, leading to more efficient and reliable operations in the oil and gas industry.

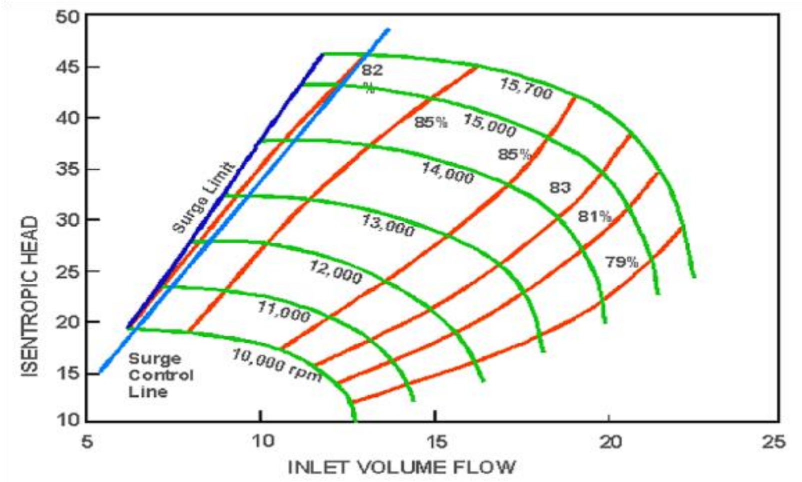


Figure 1. Compressor Map (Variable Speed) Typical.

The surge limit is the limiting factor in the case of reduced flow. Some manufacturers prohibit using their machines anywhere in the choke zone unless the head is kept in a positive state, while others do not impose such restrictions. In addition to maximum and minimum speeds, vane settings, and temperature caps, there are other restrictions. Compressor temperature limitations are not always defined by the head-flow map due to the fact that discharge temperature is additionally influenced by gas composition and suction temperature. It may be determined using the suction data and the head-flow efficiency map. The rotor's dynamic or stress limits set the maximum allowable velocity. It's important to remember that, within certain parameters, changing the inlet conditions will have no effect on the indicated performance map.

Gas Compression Thermodynamics

The isentropic head is the amount of energy needed for reversible adiabatic compression of a gas from a given suction pressure and temperature to a given delivery pressure. The energy input needed by the real compressor will be more than that required by the ideal (isentropic) compression. Mollier diagram (Figure 2) is the clearest representation of this concept. Head is the amount of effort required to cause a change in enthalpy in a gas. (Differences in work, heat, and enthalpy have no real-world analogues. Work, head, and enthalpy difference all have the same units [for instance, kJ/kg in the SI system] in consistent unit systems. The mechanical equivalent of heat (expressed in ft lbf/BTU) is connected to head and work (expressed in ft lbf/lbm) only in inconsistent systems [such as US customary units]

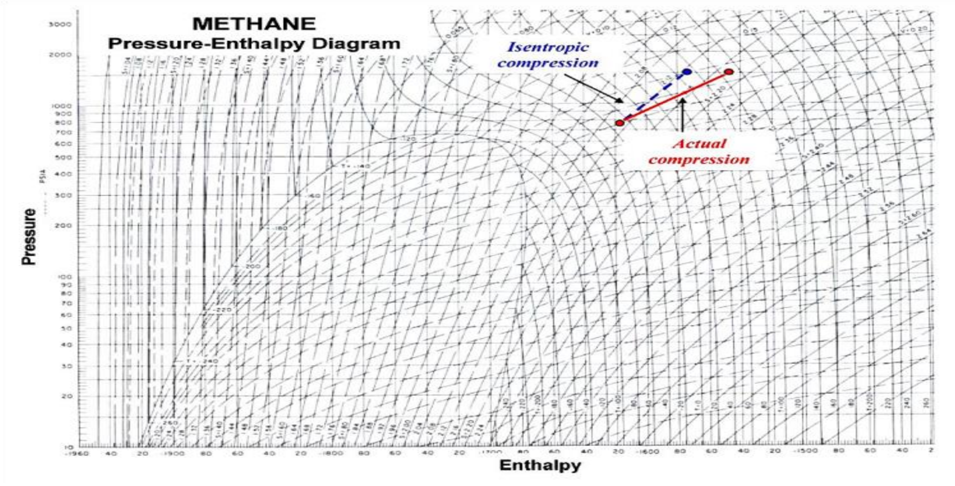


Figure 2 illustrates the methane compression process in a Mollier diagram. The Mollier diagram, also known as the enthalpy-entropy diagram, is a graphical representation that shows the relationship between temperature, specific entropy, and enthalpy of a substance.

In this specific case, methane compression is depicted. The diagram showcases the different stages of the compression process, including suction, compression, and discharge. Each stage is represented by a specific point on the diagram, indicating the corresponding temperature, entropy, and enthalpy values. By utilizing the Mollier diagram, one can gain valuable insights into the thermodynamic properties of the methane compression process. It allows for a visual understanding of the energy changes and transformations that occur during compression, providing a comprehensive perspective on the process.

Assuming the gas composition is known, the suction and discharge pressure and temperature may be used to calculate the compressor head (H). In most cases, adiabaticity is assumed for the compressor (otherwise, neither the isentropic nor the poly-tropic definitions of work and efficiency are particularly applicable). Compressors that use an inter-cooler may only be thought of as partially adiabatic. Below are several equations of state that specify the connection between pressure, temperature, and enthalpy (h). Using the equations of state (Kumar, et al., 1999), we can determine the values of the enthalpies associated with the suction, discharge, and isentropic discharge state. For the isentropic top, or H*:

$$H^* = h(p_d, s(p_s, T_s)) - h(p_s, T_s) \quad (1)$$

with isentropic effectiveness,

$$\eta_s = \frac{H^*}{H} \quad (2)$$

The true head (H), which determines the power needed and the outlet pressure temperature, is:

$$H = \frac{H^*}{\eta} = h(p_d, T_d) - h(p_s, T_s) \quad (3)$$

It's worth noting that the poly-tropic efficiency is defined in much the same way, except that it contrasts the poly-tropic process with the isentropic process. There is no difference between the poly-tropic and isentropic processes in terms of the actual head, which is what defines the absorbed power. It is necessary to know the suction pressure, suction temperature, and discharge pressure of a gas in order to completely characterize the isentropic compression process. Either the poly-tropic compression efficiency or the discharge temperature is required for defining the poly-tropic process.

The isentropic and poly-tropic processes, in particular, are examples of reversible processes. The isentropic process is the only one that truly is adiabatic, yet both apply to adiabatic systems. An unlimited number of isentropic compression phases, each followed by an isobaric heat addition, constitute the poly-tropic process. The temperature rise caused by this (reversible) heat addition is identical to the temperature rise caused by the (irreversible) losses in the actual process.

To write, it is necessary to specify the poly-tropic efficiency p so that it remains constant for infinitesimally small compression steps:

$$H = \frac{1}{\eta_p}\int_{p_1}^{p_2} vdp = \frac{H_p}{\eta_p} \qquad (4)$$

and:

$$H_p = \int_{p_1}^{p_2} vdp \qquad (5)$$

alternatively, to characterize polytropic efficacy:

$$Q(p,T) = \frac{\rho_{std}}{\rho(p,T)} Q_{std} = \frac{W}{\rho(p,T))} \qquad (7)$$

Compressor designs can indeed derive significant advantages from polytropic efficiency. When a compressor consists of multiple stages, each with the same isentropic efficiency (s), the overall compressor efficiency will be lower than s. In such cases, the use of polytropic efficiency (p) provides a more accurate representation of the machine's overall efficiency. Under the same assumptions, if each step of the compressor has the same efficiency, the overall polytropic efficiency (p) of the machine would be p. This allows for a better understanding and evaluation of the compressor's performance, as it considers the efficiency variations across different stages. To determine the actual flow (Q) of the compressor, one can utilize either the standard flow at a specific pressure and temperature (p = 14.7 psia and T = 60 °F), or the mass flow at different temperature and pressure conditions. These inputs help in calculating the density and subsequently obtaining the actual flow rate of the compressor. By considering polytropic efficiency and accurate flow calculations, compressor designs can be optimized for enhanced performance and efficiency.

Once the density is determined using an appropriate equation of state, it becomes possible to define normal circumstances or standard conditions. In most cases, standard conditions are defined at a pressure of 101.325 kPa (kilopascal) and a temperature of 0°C (degrees Celsius). These standardized conditions provide a basis for consistent comparison and analysis of various processes and systems. By establishing a common reference point, the use of standard conditions allows for easier communication and comparison of data across different applications. It helps ensure that measurements and calculations are conducted on a standardized basis, facilitating accurate analysis and evaluation. In summary, determining density through an equation of state enables the definition of normal circumstances at a pressure of 101.325 kPa and a temperature of 0°C, creating a standardized reference for consistent measurement and analysis.

$$Q(p,T) = \frac{\rho_{std}}{\rho(p,T)} Q_{std} = \frac{W}{\rho(p,T))} \qquad (7)$$

The compressor's gas power, or aerodynamic power, is calculated to be:

$$P_g = \rho_1 Q_1 H = \frac{p_1}{Z_1 R T_1} Q_1 H \qquad (8)$$

The gas compressor and gearbox (if present) also incur mechanical losses. Mechanical losses in a compressor, which account for around 2% of the absorbed power on average, are not factored into its adiabatic efficiency. All mechanical losses should be included into the projected absorbed power of a compressor. Mechanical efficiency (m), generally 98–99 percent, is added to the absorbed compressor power (P) to account for bearing losses:

$$P = \frac{P_g}{\eta_m} \qquad (9)$$

Equations of state and actual gas behaviour

The link involving gas pressure, temperature, speed density is crucial to grasping the concept of gas compression. The following characteristics define an ideal gas:

$$\frac{p}{\rho} = RT \tag{10}$$

wherein R is a constant of the gas, which remains unchanged in the absence of any changes to the gas's composition. This equation is applicable to any gas at extremely low pressures (p60).

Adding the clarity factor Z is necessary since the equation becomes erroneous at the high pressures seen during natural gas compression:

$$\frac{p}{\rho} = ZRT \tag{11}$$

Compressible factor varies with temperature, pressure, and gas type; this is a major drawback.
When calculating enthalpy, a similar problem develops. For a perfect gas, one obtains:

$$\Delta h = c_p \cdot \Delta T = \int_{T_1}^{T_2} c_p dT \tag{12}$$

where cp depends on temperature and nothing else.

Additional terminology are included in a real gas to describe the differences between its behaviour and that of an ideal gas (Poling et al., 2001):

$$\Delta h = (h^0 - h(p_1))_{T_1} + \int_{T_1}^{T_2} c_p dT - (h^0 - h(p_2))_{T_2} \tag{13}$$

Because they quantify how much the real-world behaviour of a gas differs from the ideal-world behaviour of a gas, the expressions (h0! h(p1)) T1 and (h0! h(p2)) T2 are referred to as departure functions. They establish a connection between the enthalpy at one pressure and temperature and that at a lower pressure but the same temperature as a reference condition. Since the parameter IcpdT has been assessed in the ideal gas state, the deviation functions may be derived with just an equation of state.

The compressibility factor and the departure functions are essential parameters in gas compression applications, and they can be calculated using equations of state (EOS). Equations of state are semi-empirical connections that describe the relationship between the pressure, temperature, and volume of a substance. Several commonly used equations of state for gas compression applications include: 1. Redlich-Kwong (RK) equation of state 2. Soave-Redlich-Kwong (SRK) equation of state 3. Benedict-Webb-Rubin (BWR) equation of state 4. Benedict-Webb-Rubin-Starling (BWRS) equation of state 5. Lee-Kessler-Ploecker (LKP) equation of state These equations provide mathematical models that help to predict the behavior of gases under compression. By utilizing these equations of state, engineers and researchers can accurately calculate properties such as the compressibility factor and the departure functions, which are crucial for understanding and analyzing gas compression processes. The choice of equation of state depends on the specific application and the accuracy required for the system being studied. Each equation has its own advantages and limitations, and the selection depends on factors such as the nature of the gas, the operating conditions, and the desired level of accuracy. In conclusion, equations of state such as Redlich-Kwong, Soave-Redlich-Kwong, Benedict-Webb-Rubin, Benedict-Webb-Rubin-Starling, and Lee-Kessler-Ploecker, are widely used in gas compression applications to calculate important parameters like the compressibility factor and departure functions. These equations provide valuable insights into the behavior of gases under compression.

Components of A Gas Compressor

When it comes to centrifugal compressors, single-stage machines with an overhung rotor are indeed the most common type. These machines are known for their simplicity and ease of maintenance. They consist of a single impeller mounted on an overhung rotor, where the impeller is positioned between the inlet and the outlet. In multi-stage centrifugal compressors, a beam-style rotor is commonly used. These machines comprise multiple stages, each consisting of an intake system for the first stage or a return channel for subsequent stages, an impeller, a diffuser (which can be vaneless or equipped with vanes), and a discharge collector. After the last stage of the compressor, a discharge collector or, in more advanced machines, a discharge volute is installed. This component helps collect and direct the compressed gas towards the outlet, ensuring efficient flow and pressure recovery. The intake system or return channel directs the incoming gas to the impeller, which then imparts kinetic energy to the gas. As the gas flows through the diffuser, it undergoes a velocity reduction and corresponding pressure increase. Finally, the discharge collector gathers the compressed gas from each stage and delivers it to the desired outlet. This configuration allows for increased compression ratios and higher overall efficiency, making multi-stage centrifugal compressors suitable for applications that require higher pressure ratios than what can be achieved with single-stage machines. In summary, single-stage machines with an overhung rotor are the most common type of centrifugal compressor, followed by multi-stage machines with a beam-style rotor. Each stage consists of an intake system or return channel, an impeller, a diffuser, and a discharge collector, ensuring efficient compression and effective gas flow.

Gases enter the compressor through the intake nozzle (shown in Figure 3) and are directed (often with the aid of guide vanes) to the first impeller's inlet. Rotating vanes make up an impeller, which transfers mechanical energy to the gas. When gas exits the impeller, its velocity and static pressure are both enhanced. A portion of the kinetic energy is transformed into static pressure inside the diffuser. Vaneless diffusers are also available, and so are those with many vanes. In a multi-impeller compressor, the gas is recirculated via a return channel and vanes to the next impeller. Compressed gas leaves the compressor through the discharge system after passing through the final impeller's diffuser. Either a simple cavity that gathers the gas prior to its escape from the compressor through the discharge nozzle, or a volute that further converts velocity into static pressure, can be used in the discharge system.

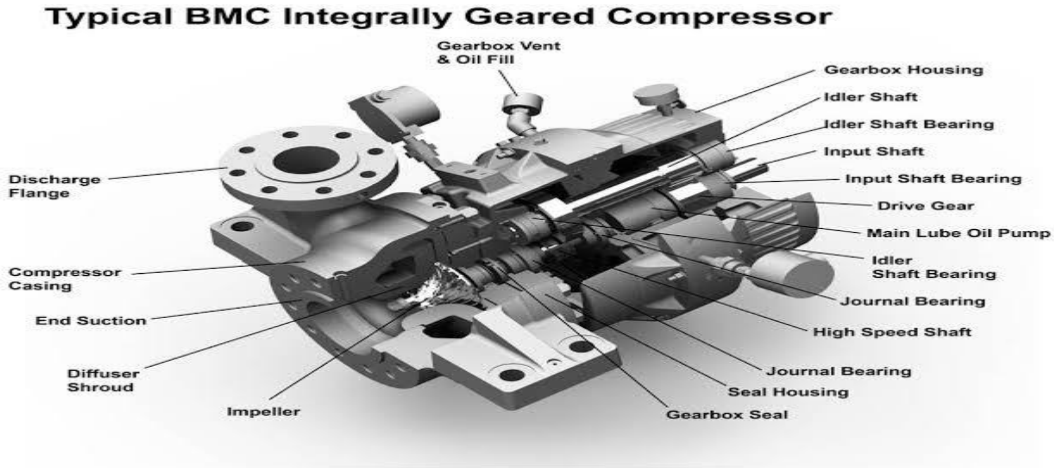


Figure 3. An Example of a Centrifugal Compressor (Image: Solar Turbines, Inc.)

The spinning component of a compressor consists of the impellers and the shaft. The impellers play a crucial role in imparting kinetic energy to the gas, facilitating the compression process. The shaft, on the other hand, transmits the rotational motion from the driver to the impellers. In modern compressors, axial thrust generated by the impellers is effectively countered to maintain stability and reliability. This is achieved through the use of a balancing piston, which helps to balance the axial forces. The resulting force is then absorbed by a hydrodynamic tilt pad thrust bearing. This bearing type provides a stable and efficient means of supporting the axial load and ensuring smooth operation. The rotor of the compressor spins on two radial bearings, which provide support and allow for the rotation of the shaft. These bearings help maintain the alignment and stability of the rotor during operation. They are designed to minimize friction and provide the necessary support for smooth rotation. In terms of rotor design, there are two common configurations. In modular rotors, the impellers are integrated into the shaft itself, as shown in Figure 4. This design offers compactness and ease of assembly. Alternatively, the compressor shaft can be a solid shaft, with the impellers either reduced in size or fastened onto the shaft. Both designs have their advantages and are chosen based on specific requirements and considerations such as manufacturing processes, maintenance, and operational efficiency. In summary, the spinning component of the compressor consists of the impellers and the shaft. Axial thrust from the impellers is countered by a balancing piston, and the resultant force is absorbed by a hydrodynamic tilt pad thrust bearing. The rotor spins on two radial bearings, and depending on the design, the impellers can be integrated into the shaft or fastened onto a solid shaft.

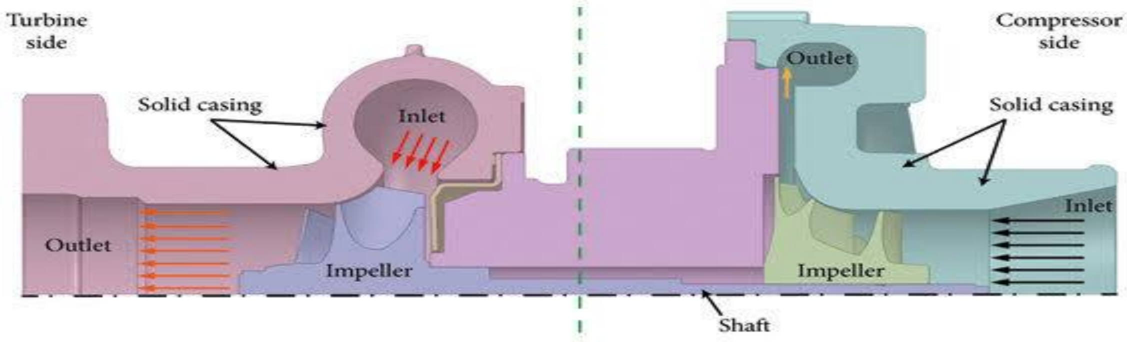


Figure 4. Construction of Centrifugal Compressor Rotors.

To ensure stability, several measures can be implemented, such as: 1. Designing the rotor system with appropriate balancing techniques to minimize imbalance. 2. Implementing effective sealing mechanisms to reduce potential excitations from seals. 3. Utilizing advanced bearing technologies that provide proper support and vibration isolation. 4. Conducting rigorous testing and analysis during the design phase to identify and mitigate potential vibration issues. 5. Regularly monitoring and maintaining the compressor to detect and address any imbalance or vibration-related problems promptly. By focusing on adequate damping and taking necessary measures to control excitations, a compressor can achieve stable rotor-dynamic behavior, leading to improved performance, increased reliability, and extended operational life. In summary, the stability of a compressor's rotor-dynamic behavior is essential for successful operation. Adequate damping of potential excitations from various sources, such as seals, impellers, and imbalance, plays a critical role in achieving this stability. By implementing appropriate measures, including proper design, advanced bearing technologies, and regular maintenance, a compressor can operate smoothly within the desired range of speeds and pressure

Dry gas seals are needed on both shaft ends to prevent gas leakage, with the exception of overhung impellers, which only need a single seal. Except for air or nitrogen compression applications, where carbon ring seals or labyrinth seals are typically utilised, practically all current centrifugal compressors use dry gas seals. To create a dry gas seal, a fixed and a spinning disc are used with a very tiny space (about 5m) between them. The seal's moveable disc is pressed onto the fixed disc by springs while the system is at rest. The compressor shaft's rotation creates a separating force between the seals thanks to the groove pattern on one of the discs, allowing the seals to operate without the mechanical contact of sealing surfaces.

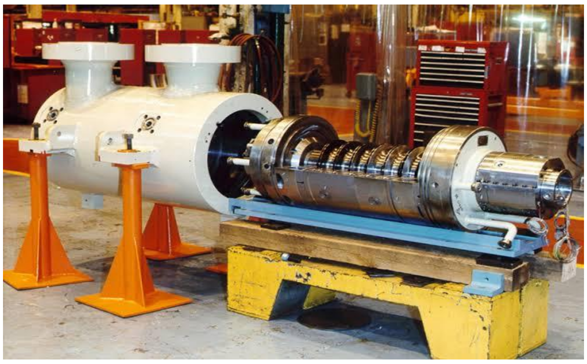
There might be a horizontal or a vertical split in the pressure-containing case (Figure 5). Both the compressor's casing and flanges need to be rated for the highest possible discharge pressure. Vertically split (barrel type) casings have been utilised effectively for discharge pressures up to 800 bar (12,000 psi), whereas horizontally split (tunnel type) casings are normally employed for lower pressure applications (up to roughly 40 bar [600 psi] discharge pressure).

In most cases, rotor-dynamic constraints dictate a maximum impeller count for a given housing. Therefore, there is a cap on how much head can be produced by a single case. When greater power is needed, it's necessary to employ numerous casings that are either driven by the same driver or by their own drivers. Compressor temperature limitations (usually capped at around 175 C/350 F at the discharge) are another potential source of head restriction. If higher pressure is needed, the gas must be cooled as it is compressed. There are a number of different layout options to choose from (Figure 6):

- Tandems with several compressor housings (up to three) operated by a single motor, maybe with a gearbox connecting the motor to the compressor train or connecting two of the compressors to each other. Compound compressors have separate suction and discharge nozzles for each of their individual chambers. All impellers rotate in the same direction and are mounted on the same shaft.

- Back-to-back compressors: Each of the compressor's two chambers has its own intake and exhaust port. While both sets of impellers share a common shaft, the impellers in the first compartment rotate anticlockwise while those in the second rotate clockwise.
- Integral gear type compressors: Each pinion is connected to an overhung impeller, and all of the pinions are powered by a central bull gear.

Both of these layouts allow for inter-cooling as well as side-streams and gas off-takes.



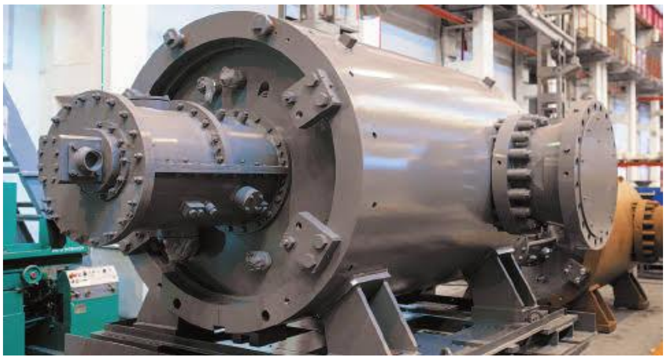


Figure 5. Centrifugal Compressor Casing Models. (Left: Removing a Bundle Using a Barrel-Style Compressor [Courtesy Solar Turbines Incorporated], Right: Compressor with a Horizontal Shaft [Courtesy Dresser-Rand Company]).

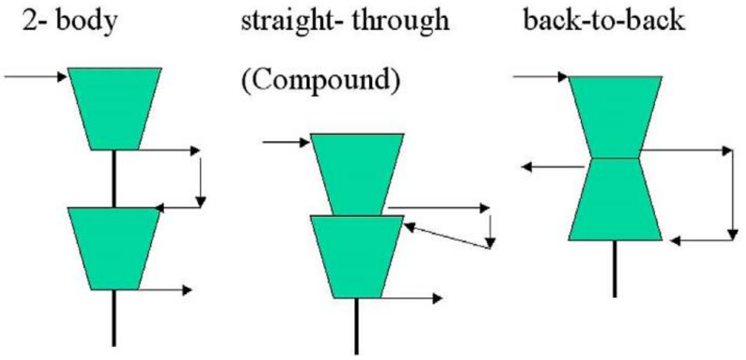


Figure 6. Compressors with Multiple Stages or Stages Back-to-Back.

Performance Not as Intended (Steady Pace)

When a compressor operates at a constant speed, it typically operates at its peak efficiency, where it achieves the highest possible efficiency for the given operating conditions (as shown in Figure 7). However, if the flow through the compressor is reduced, for example, due to an increase in the discharge pressure that the compressor needs to overcome, a steady decrease in compressor efficiency becomes inevitable. This decrease occurs because the compressor is no longer operating at its design point and is experiencing flow conditions outside its optimal range. As the flow decreases further, there is a possibility that one or more parts of the compressor, typically the impellers or diffusers, will start experiencing a phenomenon called rotating stall. Rotating stall refers to the formation of stalled flow regions within the compressor. These stalled regions disrupt the smooth flow of the gas and cause localized pressure fluctuations and reduced performance. If the flow reduction is significant or the rotating stall becomes severe, the compressor will eventually reach its stability limit and enter a condition known as surge. Surge is characterized by a reversal of flow direction in the compressor and can lead to severe vibration, noise, and potential damage to the compressor components. To prevent surge and ensure stable operation, it is crucial to operate the compressor within its stable operating range. This range is typically determined by the manufacturer and can be influenced by factors such as the geometry of the compressor, the control system, and the operating conditions. In summary, when the flow through a compressor is reduced, the compressor's efficiency decreases, and there is a risk of encountering rotating stall phenomena. If the flow reduction persists, the compressor will eventually hit its stability limit and enter surge, with adverse consequences. It is important to operate the compressor within its stable operating range to avoid these issues and maintain optimal performance.

All aerodynamic losses will rise if the flow through a compressor is decreased while the speed remains constant. Eventually, the flow will split in one of the aerodynamic parts, often the diffuser but occasionally the impeller inlet. It is important to remember that stall typically manifests in the first stage of a compressor.

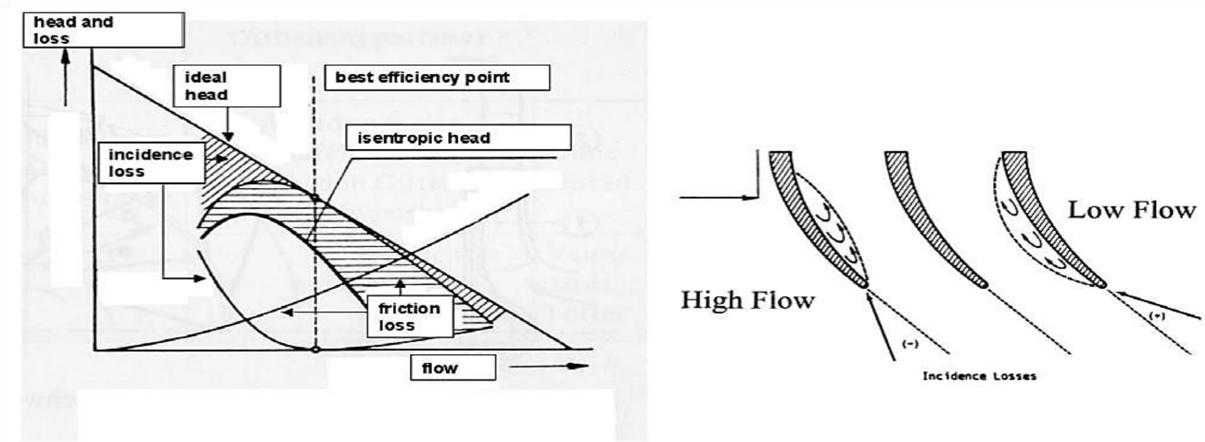


Figure 7. Off-Design Points of the Compressor.

All or a portion of the flow may not leave the diffusion device at the point of discharge due to flow separation, creating zones where the flow either stops moving forward or reverses direction and returns to the diffuser's entrance (the impeller exit).

When the flow rate through the compressor varies, the direction of the incoming flow changes relative to the revolving impeller, leading to a stall in the impeller intake or a vanned diffuser. Diffusers with vanes often have a smaller working range for a stage than those without vanes. Therefore, a decrease in flow will exacerbate the already existing mismatch between the impeller's intended flow trajectory and the actual flow pattern. Eventually, the disparity between the two grows too great, and flow is disrupted within the impeller.

Flow separation might resemble a revolving stall in appearance. Reduced flow across the compressor stage causes flow separations in the diffuser. When the flow separation areas are not fixed but instead move in the direction of the spinning impeller (usually between 15 and 30 percent of the impeller speed), this is known as a rotating stall. Rising vibration signatures in the sub-synchronous area are a common early indicator of rotational stall. The onset of stall is not always a compressor's operational limit. It's well knowledge that there's room for further flow reduction before reaching the true stability limit.

When the flow is raised from the most efficient starting point, efficiency drops and head drops with it. The compressor's head and efficiency will inevitably decline precipitously over time. Clamping down on operations is known as a choke. When the compressor's head drops below a particular % of the head at the best efficiency point, it is said to be in choke. Some compressors cannot be used in deep choke because the manufacturer forbids it. Each speed line in such a circumstance has its own high flow limit on the compressor map.

This decrease in efficiency is primarily due to increased internal velocities, which, in turn, result in higher friction losses within the compressor. As the flow rate increases, the internal velocities within the compressor also increase. These higher velocities result in increased friction losses as the gas interacts with the compressor's stationary and rotating components. These friction losses contribute to a decrease in the compressor's head, which is the pressure rise across the compressor. Centrifugal compressors that utilize backward-bent blades, as commonly seen in industrial applications, typically experience a decrease in head as the flow rate increases. This characteristic is observed even in the absence of other losses because of the inherent kinematic connections and design features of the compressor. At a certain point, as the flow rate continues to increase, the compressor reaches a flow condition called "choke." Choke occurs when the flow reaches its maximum limit, and any further increase in flow does not result in a significant increase in pressure rise. This is due to limitations in the compressor's geometry and design. The choke phenomenon is an important consideration for compressor operation, as operating the compressor at or near choke conditions can lead to unstable performance and potential damage to the compressor. It is crucial to operate the compressor within its recommended operating range, away from choke conditions, to maintain optimal efficiency and performance. In summary, higher flow rates in a centrifugal compressor can lead to reduced efficiency due to increased internal velocities and subsequent friction losses. Centrifugal compressors with backward-bent blades typically experience a decrease in head as flow increases, even without considering other losses. Operating the compressor within its recommended range and away from choke conditions is important to ensure stable and efficient performance.

Margin of Growth and Decline

Any operational A-point can be described by its proximity to the surge commencement. There are two common understandings: The safety cushion:

$$SM(\%) = \frac{Q_A - Q_B}{Q_A} \cdot 100 \tag{14}$$

This is calculated using the constant speed inflow margin between the point of operation and the peak point, and the turn-down:

$$Turndown(\%) = \frac{Q_A - Q_C}{Q_A} \cdot 100 \tag{15}$$

This relies on the difference in flow rate between the steady-state operating point and the constant-head surge point.

Control of The Compressor

The authors have already covered the compressor's default operating characteristics. In this situation, the flow is uniquely determined by the head the compressor has to create.

The compressor's capacity to adapt to a greater variety of operating situations may be improved in a number of ways:

- Speed Modulation
- Vanes at the inlet
- Dispersal vanes
- Suction/discharge control valves
- The Recycling

Modulating in Pace

Drivers for the compressor that can switch between fixed and variable speeds include two-shaft gas turbines, steam turbines, turboexpanders, electric motors with variable frequency drives, and variable-speed gearboxes. The higher the compressor's RPM, the more power it requires to produce the same number of head and flow. Since the compressor's efficiency features are preserved throughout a wide range of operating speeds, this is a highly effective method of tuning the compressor to meet a variety of needs. You can see the finished map in Figures 1 and 8.

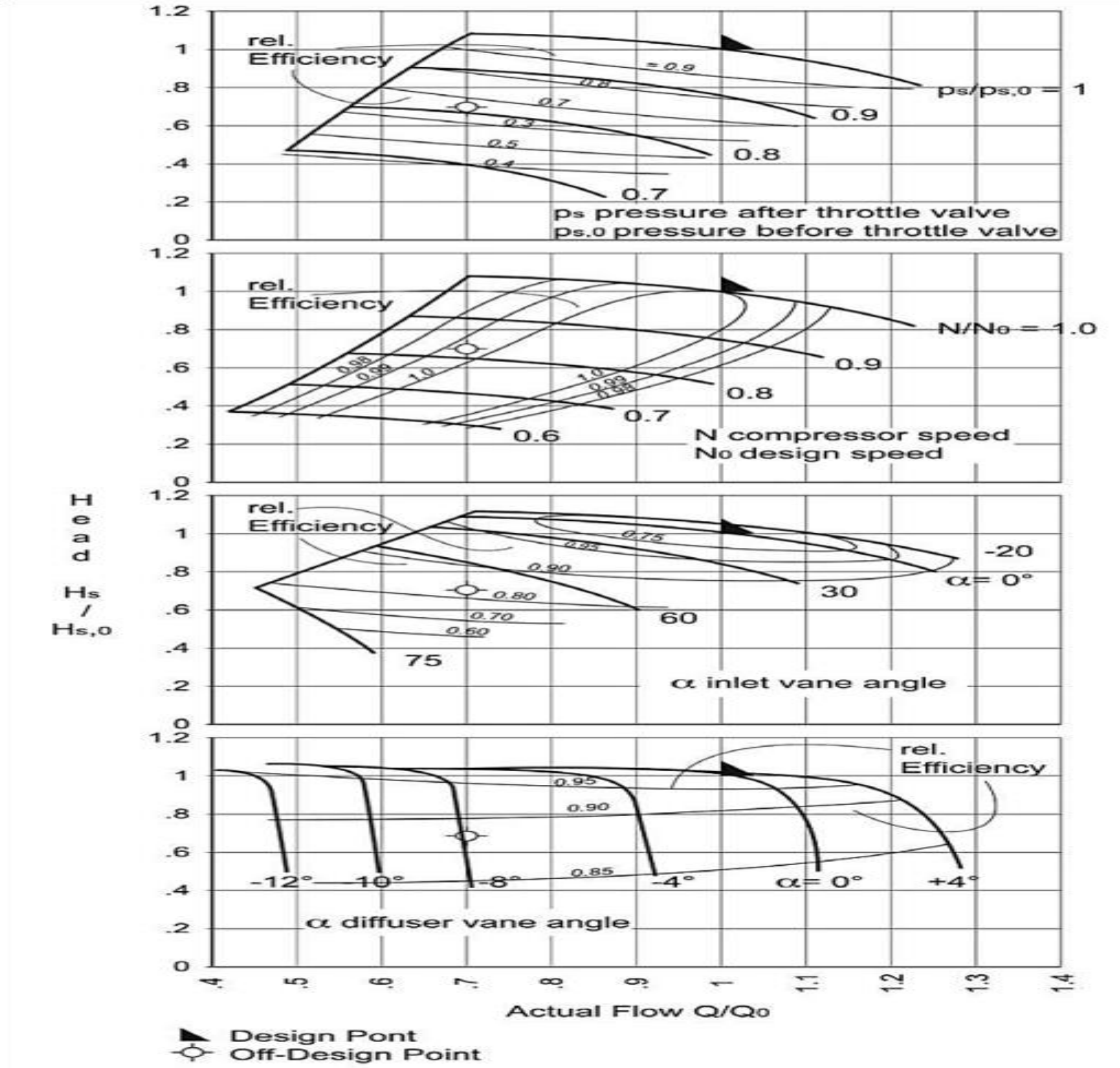


Figure 8: Introducing the cutting-edge capabilities of a state-of-the-art single-stage compressor - a true marvel of engineering! This remarkable compressor comes equipped with an array of advanced features, including the dynamic Suction Throttle, Variable Speed mechanism, Variable Inlet Vanes, and Variable Diffuser Vanes

These sophisticated components work in perfect harmony, seamlessly optimizing the compressor's performance to unprecedented levels. Imagine a compressor that adapts to its operating environment with remarkable intelligence and precision. The Suction Throttle intelligently regulates the flow of air, ensuring optimal efficiency at all times. Meanwhile, the Variable Speed control allows for seamless adjustment of the compressor's operating speed to match the exact requirements of the task at hand, resulting in remarkable energy savings and enhanced performance. But that's not all - the Variable Inlet Vanes and Variable Diffuser Vanes take this compressor to a whole new level of versatility. These ingeniously designed vanes provide precise control over the inlet and diffuser sections, allowing for impeccable optimization of air flow, pressure, and temperature. The result? Unparalleled efficiency, unbeatable performance, and the ability to tackle even the most challenging industrial applications with ease. In short, this advanced single-stage compressor is a true game-changer, pushing the boundaries of what's possible in compressor technology. With its intelligent and adaptive features, it promises to revolutionize the way we approach industrial compression, setting a new standard for efficiency, performance, and overall excellence.

Flow Regulating Inlet Vanes
The stage's working parameters may be adjusted by adjusting the swirl of the flow entering the impeller (Figure 8). Upstream of the impeller, movable vanes can be used to achieve this. Growing the swirl counter to the impeller's rotation boosts head and flow through the stage. This is an excellent method for extending the effectiveness of a single stage's output. Adjustable vanes in stages beyond the first are typically unnecessary in multistage compressors. Complicated mechanical connection needs to be actuated from outside the pressure containment body, which is a technological challenge for high pressure compressors.

Vanes for Diffusion, Variable
Because the vanes are more likely to stall under off-design circumstances, vanned diffusers restrict the working range of the compressor. Diffusers with movable vanes may adapt to their environment and operate at significantly lower flows by delaying the onset of stall (Figure 8). The stage's head or flow capacity will not improve as a result of their addition. Adjustable vanes in only one stage of a multistage compressor can only enhance the range by so much. High pressure compressors present a technological challenge because of the need for external actuation of a complex mechanical connection. There's also the fact that the vanes can't do their job unless there are tiny spaces between them and the diffuser's walls. Leakage via these crevices is ubiquitous, and it costs machines, especially those with narrow diffusers, efficiency and range.

Suction/discharge throttling
When aiming to increase the pressure ratio in a compressor, a throttle valve can be strategically positioned on either the suction or discharge side. This valve effectively adjusts the operating point to lower flow rates on the constant speed map, resulting in the desired increase in pressure ratio. While this method of managing compressors is highly effective, it is important to note that it can be somewhat inefficient, as depicted in Figure 8. It's crucial to strike a balance between efficiency and effectiveness when utilizing this approach. While it may achieve the desired results in terms of pressure ratio, the wasteful nature of this method calls for careful consideration. Exploring other advanced techniques and technologies could potentially offer more efficient alternatives for managing compressors. By continuously seeking innovative solutions and leveraging cutting-edge advancements, we can strive for optimal efficiency and effectiveness in managing compressors, ultimately maximizing performance while minimizing waste.

The Recycling
A portion of the process flow can be recycled from the compressor discharge to the suction side of the compressor under regulated conditions. Because of this, the compressor will sense a greater flow than the actual process flow. This method of allowing the compressor system to function at low flow is extremely effective yet wasteful.

Centrifugal compressor process control using two-shaft gas turbines
The following is an explanation of a common control scenario, in this instance for compressors with variable-speed gas turbine drivers. When powered by two shaft gas turbines, centrifugal compressors are often speed-controlled to respond to changing process conditions. Because a two-shaft gas turbine's centrifugal compressor and power turbine may run at a variety of speeds without experiencing any negative impacts, this is a highly elegant method of system control. A common setup may function at 50% and frequently much lower than its maximum continuous speed. The use of contemporary, programmable logic controller (PLC) based controllers allows for continuous load following due to the extremely quick reaction times.

Flow control is a prime example of efficient management in compressor systems. To regulate the flow, a flow metering component, such as a flow orifice, venturi nozzle, or ultrasonic device, detects the incoming flow. The operator sets a desired flow value as a reference point. Using this information, the controller responds by adjusting the fuel flow into the gas turbine. If process modifications cause an increase in discharge pressure, the controller acts accordingly, increasing the fuel flow. This, in turn, augments the output of the power turbine, causing it to accelerate along with the driven compressor. As a result, the desired compressor flow is maintained, ensuring stable and efficient operation. By effectively monitoring and controlling the flow, this approach ensures that the compressor system operates optimally, responding promptly to changes and maintaining the desired flow rate. This dynamic flow control mechanism enables efficient operation and helps achieve the desired performance, as illustrated in the accompanying figure.

The controller, when faced with changes in the process, will indeed decrease the fuel flow into the gas turbine if there is a decrease in discharge pressure or an increase in suction pressure. By reducing the fuel flow, the power turbine generates less power, causing it to slow down along with the driven compressor. This ensures that the compressor flow is maintained despite the changes in the process conditions. This intelligent control mechanism allows for dynamic adjustment of the fuel flow, ensuring that the compressor system responds effectively to variations in pressure. By actively managing the fuel flow, the system maintains stability and efficient operation, providing reliable performance throughout process fluctuations.

There are comparable control systems available to maintain a constant discharge pressure or suction pressure. Running the device at its maximum driver power (or any other constant driver output) is another conceivable control mode. In this instance, the speed will fluctuate even if all of the operational locations are on a line of constant power. The control system may be configured to run both parallel and series operations on one or more compressors.

The compressor can be fitted with variable guiding vanes or a suction throttle if speed control is not possible. The latter is quite useful provided it is accessible in front of each impeller, but higher-pressure applications typically find the mechanical complexity to be prohibitive. The latter is a mechanically straightforward method of control, but it reduces overall effectiveness.

Interaction of The System

Compressor controls (such as speed, power, vane settings, etc.) and system factors always interact to determine the compressor's operating point. Typically, the relationship between compressor head and flow may be used to characterize the system. Common examples include:

1. Systems that demand an increase in head as flow increases.
2. Systems needing a constant head (more or less) with a change in flow.

In some systems, where a lot of data may be stored:

3. Third, the number of head needed is determined by the current flow.

All pipeline systems qualify as examples for 1, including transmission pipes and gas collecting networks. Separators and other pieces of process equipment that require a steady pressure level are common in Type 2 systems. Large reservoirs are another case in point, as are circumstances where the gas must be pumped into a pipeline that maintains a relatively constant pressure. Another instance is air compressors that supply (and maintain) plant air pressure. Most methods of refrigeration also that a pressure be maintained constant regardless of the direction of flow. The third type of system is commonly used for storing and retrieving items.

It should be emphasized that most systems have a transitory characteristic that differs from their steady-state characteristic. Gas inertia and mass storage effects must be taken into account during transient operations.

The operational point of a compressor is found where a performance map representing that feature of the compressor and the system intersect.

Let me elaborate on the concept of a pipeline program that involves a compressor station operating within a pipeline system. This program takes into account the lengths of the upstream pipe (Lu) and the downstream pipe (Ld), as well as the known and constant pressures at the start of the upstream pipe (pu) and the end of the downstream pipe (pe). To understand the pressure gradient within the pipeline, we utilize the Fanning equation. This equation provides a means to explain the changes in pressure along the pipeline: [Insert Fanning equation here] By applying the Fanning equation, we can evaluate and analyze the pressure variations in the pipeline, taking into consideration factors such as pipe lengths and the known pressures at both ends. This equation enables us to gain insights into the pressure gradient and better understand the behavior of the pipeline system. Figure 9, as referenced in the description, likely illustrates the visual representation of the compressor station and its interaction within the pipeline system. This visual aid helps in visualizing the functioning and connectivity of various components within the pipeline network. Overall, this pipeline program, with the utilization of the Fanning equation and a compressor station, allows for a comprehensive understanding and management of pressure variations within the pipeline system.

$$\frac{dp}{dx} = -32f\,\frac{\rho_{std}Q_{std}^{\;2}}{\pi^2 D^3} \qquad (16)$$

Indeed, assuming that the friction factor (f) remains constant, we can proceed with integrating the relevant equations. As a result, the pipeline system will impose a pressure (ps) at the suction side of the compressor and a pressure (pd) at the discharge side, all while maintaining a fixed flow rate (Qstd). By considering the friction factor as constant, we can more easily analyze and model the behavior of the pipeline system. This assumption allows us to focus on the impact of other factors, such as pipe lengths, known pressures, and fixed flow rate, without the added complexity of varying friction factors. With this integrated approach, we can accurately determine the pressures at the suction and discharge sides of the compressor, taking into account the specific characteristics of the pipeline and its impact on the flow rate. This enables us to optimize the performance of the compressor station within the pipeline system, ensuring efficient and reliable operation. By understanding the relationship between pressure, flow rate, and the unique parameters of the pipeline, we can effectively manage and control the pipeline system, maintaining the desired flow rate while ensuring appropriate pressures at both the suction and discharge sides of the compressor.

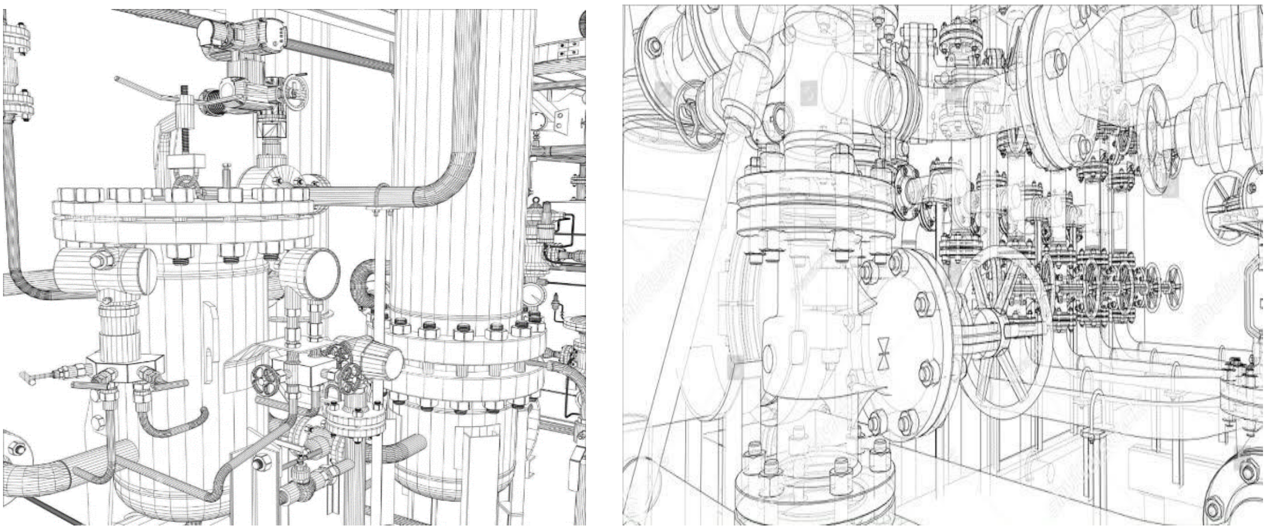


Figure 9. Plans for a Pipeline.

According to Kurz and Lubomirsky (2006), the head-flow connection at the compressor unit may be roughly approximated for a particular pipeline under steady-state circumstances by:

$$H^* = C_p T_s\left[\left(\sqrt{\frac{1}{1-\frac{C_3+C_4^{'}\cdot Q^2}{p_d^2}}}\right)^{\frac{k-1}{k}} -1\right] \qquad (17)$$

where C3 and C4 are variables (for a certain pipeline shape) that, respectively, describe the pressure at the pipeline's two ends and the friction losses.

Equation (17), which considers known pipeline losses and specifies the station pressure at the discharge, establishes a direct connection between the conveyed flow in the pipeline and the required head. While this might initially seem restrictive, it is important to keep in mind the underlying objective. In a transmission system, maximizing flow is crucial, and this can be achieved by ensuring that the station pressure at the discharge is maintained at or near the pipeline's maximum working pressure. By setting the station pressure at the discharge to this level, we optimize the flow capacity of the transmission system. This approach allows us to efficiently utilize the pipeline's capacity and convey the maximum amount of fluid possible, while still considering the known pipeline losses.

Though this approach may seem restrictive in terms of station pressure, it is a strategic decision aimed at achieving optimal flow rates within the limitations of the pipeline system. By working within these parameters, we can effectively manage and maximize the transmission capacity of the pipeline, ensuring the efficient and reliable conveyance of fluids.

In the context of a pipeline system, the required head at the compressor station for a specific flow rate is determined by the characteristics of the pipeline itself, as depicted in Figure 10. This unique attribute emphasizes the importance of a compressor's capacity to vary the head in response to changes in flow rate. By having the capability to adjust the head in a predetermined manner, the compressor can enable a reduction in head with a decrease in flow rate and vice versa. This flexibility ensures that the pipeline system can maintain a constant head (or pressure ratio) without the need to modify the flow rate. This ability to vary the head in response to changes in flow rate is crucial for the optimal operation of the pipeline system. It allows the compressor to adapt to the varying demands of the system while maintaining a consistent and efficient flow of fluids. By efficiently managing the head and flow rate relationship, the compressor plays a vital role in ensuring the stability and reliability of the pipeline, ultimately enabling the system to operate smoothly and effectively.

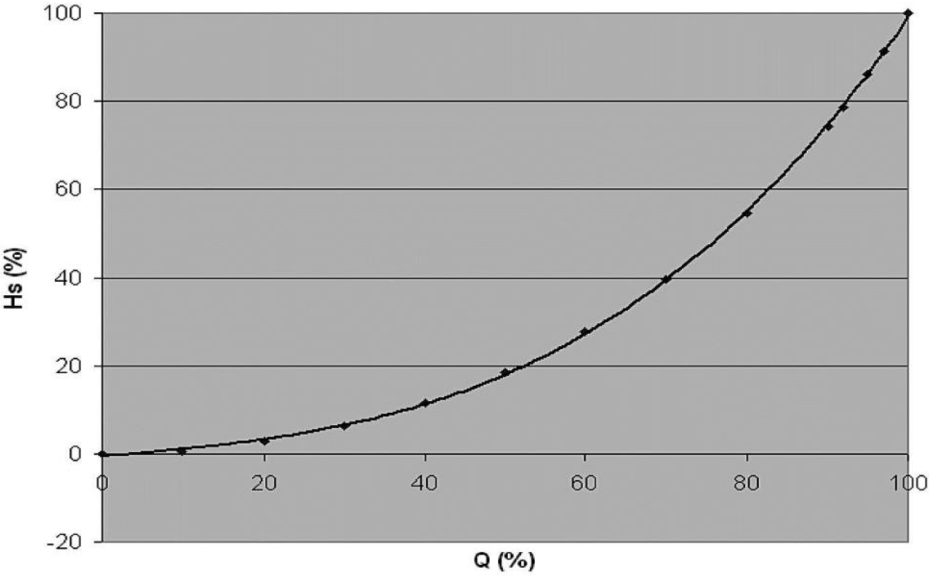


Figure 10 represents the relationship between the station head and flow in accordance with Equation 17. This figure illustrates how the control of the compressor plays a critical role in managing this relationship within the pipeline system.

The control of the compressor refers to the ability to adjust and regulate its operation to maintain the desired head and flow rate.

By effectively controlling the compressor, operators can ensure that the station head aligns with the required flow, as determined by the pipeline system. This control mechanism allows for dynamic adjustments in the compressor's operation, such as varying the rotational speed, adjusting the throttle valve, or modulating the fuel flow. These control actions enable the compressor to respond to changes in demand and maintain the desired station head for the specified flow rate. By closely monitoring the conditions within the pipeline system and utilizing advanced control strategies, operators can optimize the performance of the compressor, ensuring that the station head and flow are maintained in accordance with the requirements of the pipeline. Figure 10 serves as a visual representation of this relationship and highlights the significance of effective compressor control in achieving the desired head and flow characteristics within the pipeline system.

The engine's compressor output needs to be regulated to fit the system demand based on the aforementioned specifications. The connection between system flow and system head, or pressure ratio, defines this system demand. Given the wide range of operating situations that compressors encounter, it is crucial to understand how to modify the compressor for each situation and, in particular, how this affects efficiency.

A common property of compressors that use centrifugal force is the flattened head versus flow feature. The actual process through the machine is therefore significantly impacted by variations in the pressure ratio. With increased flow, a centrifugal compressor's head or pressure ratio decreases while it runs at a constant speed.

The operating point of a compressor within a pipeline system is influenced by several factors, including the head-flow property of the system, the compressor's map, and the available power to operate the compressor. The head-flow property of the system refers to the relationship between the required head and the corresponding flow rate within the pipeline. This property is determined by the characteristics of the pipeline, including its length, diameter, and the fluid being transported. The compressor needs to operate at a point that aligns with this head-flow relationship to ensure efficient and reliable performance. The compressor's map, also known as the performance curve, provides information about the compressor's characteristics and capabilities. It shows the relationship between pressure ratio (head) and flow rate (mass flow or volumetric flow) for various operating conditions. The compressor's operating point is determined by matching the required head and flow rate from the system to the corresponding point on the compressor's map. Additionally, the available power to operate the compressor is a crucial factor in determining the operating point. The power required to drive the compressor is dependent on the system's head and flow rate, as well as the efficiency of the compressor. The available power needs to meet or exceed the power required by the compressor to ensure it operates optimally. By considering the head-flow property of the system, the compressor's map, and the available power, operators can determine the appropriate operating point for the compressor. This ensures that the compressor operates within its designed range, delivering the required flow rate and head while utilizing the available power efficiently.

The Control of the Surge

Systems for surge control are inherently surge avoidance systems. Typically, the compressor's head and the gas flow through it are measured by the control system. Knowing the head and flow allows you to compare the compressor's current operating point to the anticipated surge line (Figure 1). A recycling valve in a recycle line is opened if the procedure requires the compressor to approach the surge line (see above). As a result, the compressor's real operating position can be moved away from the surge (Kurz and White, 2004; White and Kurz, 2006). It is possible to keep the compressor running while reducing the station flow to zero using well-designed surge control systems. Additionally, they will ensure that the process doesn't suffer throughout the transition from a totally closed recycling valve to one that opens up more and more.

Multiple Process Streams Control

Multiple process streams must frequently be handled by compressors or compressor trains. The compressor train requires N control devices in order to regulate N streams. For instance, a two-body tandem with a single side-stream can be managed by combining a train-wide speed control with a side-stream throttle valve. A unit recycling loop can be another option in this situation for control.

Initiation and Termination

Pay close attention to the beginning and end of each step. The driver's speed-torque capabilities and the recycling system's thermal balance are also important factors to think about. The former is a common problem with electric motor drives since the amount of available motor torque is frequently constrained by the capacity of the electrical grid or the production of electricity. The latter entails the compressor pumping gas in the recycling loop until the pressure it creates is sufficient to go online. Due to the work the compressor puts into the gas, the temperature will rise in an uncooled recycling loop, and if it reaches a particular point, the start will be cancelled. White and Kurz (2006) provide a more in-depth discussion of this topic.

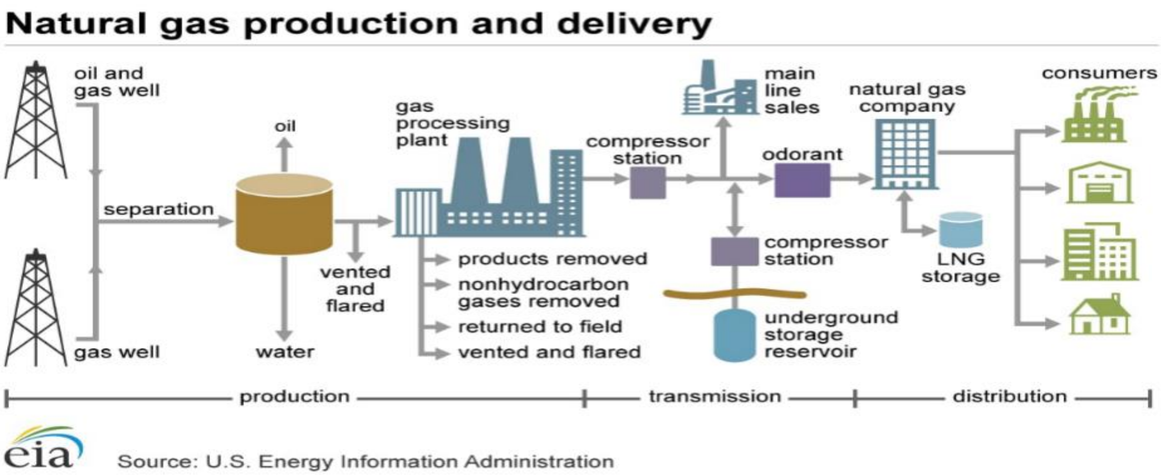
Additional and Replacement Units

The total flow or process pressure ratio can be broken down into many units depending on the specifics of the application. This is useful because it allows for more process flexibility, which is a significant benefit. If the flow demand drops, for instance, one of the units can be turned down entirely without resorting to recycling mode.

The station's accessibility should also be taken into account. This covers both scheduled maintenance and unscheduled equipment shutdowns. One complete spare might be a configuration option. The backup system's specs would be set to match those of the primary system. By breaking the process down into several smaller units, the loss of output from the shutdown of a single unit can be mitigated, and a backup unit may be unnecessary.

How Do We Get Our Oil And Gas?

The goal is to maximise the amount of oil or gas that can be extracted from a reservoir after it has been located and evaluated. The reservoir rock's pores are where the oil and gas are stored. It is simpler to extract oil and gas from reservoirs that don't restrict the flow of the hydrocarbons. Other reservoirs limit the flow of oil and gas, necessitating unique methods to transport the liquids from the pores to a well that can extract them. More than two-thirds of the oil present in some reservoirs may be unrecoverable even with modern technology. The flow of gas is depicted in Figure 11 from the well to the consumer. Offshore platforms are needed for oil and gas production since many wells are located on the ocean floor (Figure 12).



"Figure 11: illustrates the route that natural gas takes from its source to its final destination. It showcases the various stages and processes involved in safely transporting and distributing natural gas to consumers."

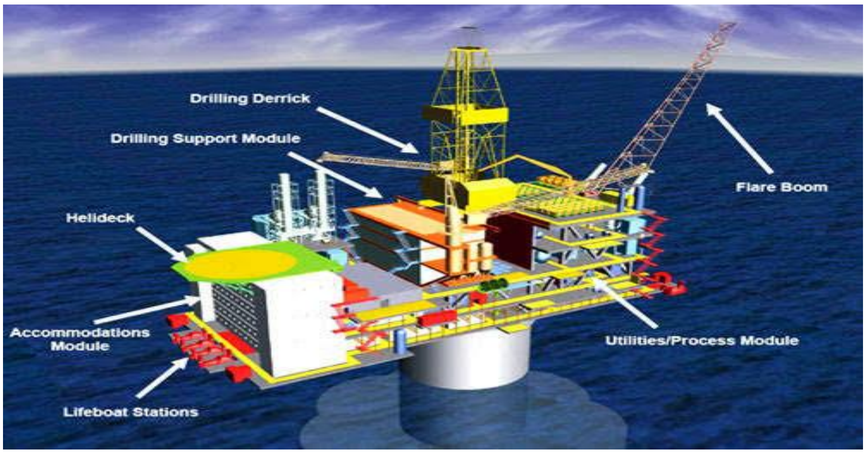


Figure 12 - the offshore platform: "Picture a majestic steel structure rising out of the deep blue sea like a modern-day Atlantis.

Figure 12 showcases an offshore platform that serves as a bustling hub of activity in the middle of the ocean. It's like a compact city on stilts, with towering cranes, helipads, and intricate pipelines connecting to various subsea wells. This engineering marvel stands strong against the elements, harnessing the power of the ocean to extract valuable resources and bring energy to the world. It's like a floating fortress of innovation, where humans and technology come together to conquer the depths and harness the vast potential of the offshore realm."

Casing (lengths of pipe cemented in place) are used to stabilize the bore hole prior to oil production. Packers secure a string of tubing with a narrow diameter in the middle of the well bore. The hydrocarbons will be transferred from the reservoir to the surface via this tube.

The pressure in the reservoirs is usually rather high. To control the release of hydrocarbons, a "Christmas tree" of valves and other apparatus is mounted on top of the well.

Hydrocarbons are typically forced to the surface by subsurface pressure early in a well's production life. This "natural flow" might last for a very long time, depending on the state of the reservoir. When the pressure difference is too small for the oil to rise to the surface on its own, mechanical pumps are employed to do the job. Artificial lift is the term for this method.

Most wells have a predictable production pattern where output rises for a while, peaks, and then gradually decreases over time (Figure 13). Reservoir conditions determine the form of this decline curve, the height of the production peaks, and the duration of the drop. Drilling new wells, using enhanced oil recovery methods, and fracturing or treating the reservoir rock near the bottom of the well-bore can all affect the decline curve.

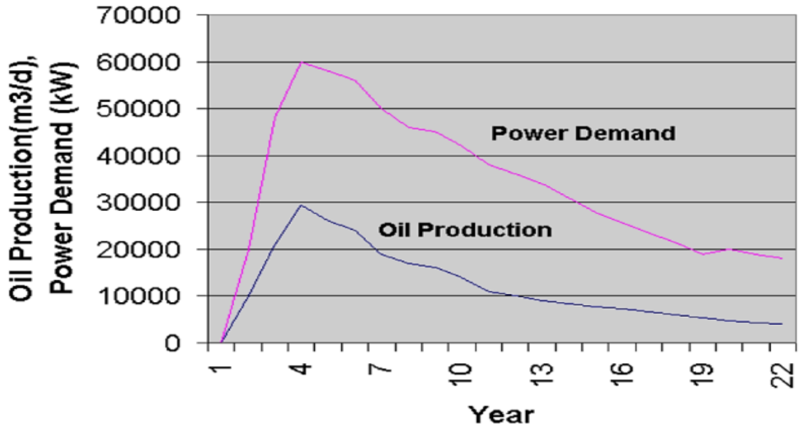


Figure 13. Normal Fall in Offshore Oil Production and Electrical Demand

One of the key principles of oil movement in reservoirs is that it tends to settle between lighter natural gas above and heavier groundwater below. However, this theory was discovered to be an oversimplification when geologists started studying the behavior of real oil fields more closely. Through their research, they found that the dynamics of oil movement within reservoirs is more complex and influenced by various factors. To enhance oil recovery, geologists and engineers have developed techniques such as water-flooding, where water is injected into the reservoir, as well as other substances like hydrocarbons, steam, nitrogen, and carbon dioxide. These injections help to create pressure within the reservoir, displacing the oil and pushing it towards production wells. By doing so, they aim to extract more crude oil from the interior pores of the reservoir and improve overall production. The ongoing research and advancements in enhanced oil recovery techniques continue to shape our understanding of how oil behaves in reservoirs. This knowledge enables us to optimize extraction methods and maximize the potential of oil fields.

Time-lapse video seismic monitoring, also known as "4-D monitoring," has played a crucial role in studying oil reservoirs in a dynamic manner. This technique involves capturing continuous video footage over time to observe changes in the reservoir's behavior. Through these monitoring efforts, geologists have discovered that the behavior of oil in reservoirs is more intricate than previously thought. Oil tends to mix with gas and water due to the complex and fractal nature of the well's drainage pattern. This insight has highlighted the potential dilution of oil within the reservoir. To address this, unconventional methods such as injecting natural gas, steam, carbon monoxide, or nitrogen into the reservoirs have been employed. These injections serve the purpose of enhancing oil recovery by pushing oil that would have otherwise remained trapped in the rock towards the existing production wells. By utilizing gas reinjection techniques, the aim is to minimize oil wastage and maximize extraction efficiency. This approach helps to optimize the recovery of oil reserves and reduce the amount of oil that may have been left behind using conventional methods. The continuous advancements in understanding reservoir behavior and the development of innovative techniques like gas reinjection contribute to the ongoing efforts to enhance oil recovery and maximize the utilization of our valuable resources.

When oil is extracted from wells, it typically comes with other byproducts such as gas and water. The mixture of oil, gas, and water needs to undergo a separation process to separate the components. Initially, the first output from an oil well will mainly consist of oil with only a small amount of water. However, as production continues over time, the water content gradually increases. This increase in water content is a natural occurrence in many oil wells. The composition of the generated water can vary significantly. It can range from extremely salty to relatively fresh, depending on the characteristics of the reservoir and the geological formations surrounding it. In order to manage and handle the water generated from oil production, there are several options. One common approach is to re-inject the water back into the reservoir as part of a water-flooding project. Water injection can help maintain reservoir pressure and improve oil recovery. Alternatively, if the water cannot be utilized for other purposes or re-injected into the reservoir, it can be disposed of by safely returning it back into the subsurface. This ensures that the water is properly contained and does not have a negative impact on the environment. Efficient management of the byproducts, including the separation and appropriate handling of oil, gas, and water, is an important aspect of oil production to ensure sustainable and environmentally responsible practices.

The oil is subsequently transported to a refinery or processing facility. There, it undergoes multiple phases of pressure reduction during processing in a gas-oil separation system. Accompanying gas (also known as flash gas) is discharged in a separator at each step of decompression until the pressure is just above atmosphere level. After being heated, the crude oil is pumped into a stabilizer column and flows down a series of bubble trays. Sweetened heavy crude is withdrawn from the bottom of the column, while hydrogen sulphide (if present) and any leftover light hydrocarbons are collected at the top. The oil is stabilized, cooled, and stored. Environmental rules are followed in the processing of the streams gathered at the top of the stabilizer unit.

Instead of oil, natural gas wells create a byproduct of hydrocarbons in liquid form known as condensate. At a gas purification facility, contaminants like hydrogen sulphide and dioxide of carbon are extracted with condensate and natural gas-based liquids like ethane, propane, and butane. The usefulness of natural gas liquids as a petrochemical feed-stock is substantial. Water is a further prevalent byproduct of natural gas extraction, albeit the amounts are typically considerably smaller than those of oil wells.

Except in exceptional circumstances when a pipeline would be too costly to construct, pipelines are the primary means of transporting natural gas. In such instance, it is possible to reduce the gas into a liquid (called LNG, or liquefied natural gas) and transfer it via ship. Pipelines can transfer gas to storage facilities, which often make use of decommissioned gas fields or salt caverns. This enables for the seasonal or daily balancing of the demand and supply sides.

Upstream applications are those that occur before a gas plant, while midstream applications are those that occur between the gas plant and the end customers. "Downstream" applications are those used in manufacturing operations such as refinery and chemical manufacturing plants.

Applications

The writers have made every attempt to adhere to the accepted terminology in the following paragraphs. However, there is considerable overlap between the various classifications, and a single compressor or train of compressors may serve multiple purposes. Example implementations are provided to demonstrate the many uses. The authors of the paper will directly establish the head and actual flow rates from the information being processed, as described in the section about the laws of thermodynamic above, unlike previous publications that demonstrate hand calculations (which the authors would recommend for anyone who has to do similar calculations). This corrects for a major error introduced when adapting calculations for ideal gases to those of actual gases. The authors also utilize conventional isentropic compressor efficiencies rather than the more common poly-tropic ones (a more achievable approach, as their presumption of constant poly-tropic stage performance does not hold in practice).

Many installations have everything requested to do many tasks (see Fig. 14 and 15).

Figure 14 showcases several important functions of an offshore platform

Let's take a closer look at each of them:

1. **Compression for Depletion (Gas-Re-Injection)**: One of the functions of an offshore platform is to facilitate gas reinjection. This involves compressing natural gas and injecting it back into the reservoir. This process helps maintain reservoir pressure, improve oil recovery, and maximize the extraction of valuable resources.

2 . **Stabilization of Condensate (Gas Gathering):** Another key function is the stabilization of condensate. Condensate is a valuable liquid hydrocarbon that is often found along with natural gas. The offshore platform provides facilities to separate and stabilize this condensate, ensuring its quality and suitability for further processing and transportation.

3. **Export to an Onshore Gas Plant through a Sub-sea Export Pipeline:** Offshore platforms play a vital role in facilitating the export of produced gas to onshore gas processing plants. This is achieved through sub-sea export pipelines, which transport the gas from the platform to the onshore facility. These pipelines are designed to ensure the safe and efficient transfer of gas over long distances. By performing these functions, offshore platforms enable the efficient and effective production, processing, and transportation of natural gas and associated condensate. They serve as critical hubs for offshore operations, optimizing the utilization of offshore resources and contributing to energy production onshore.

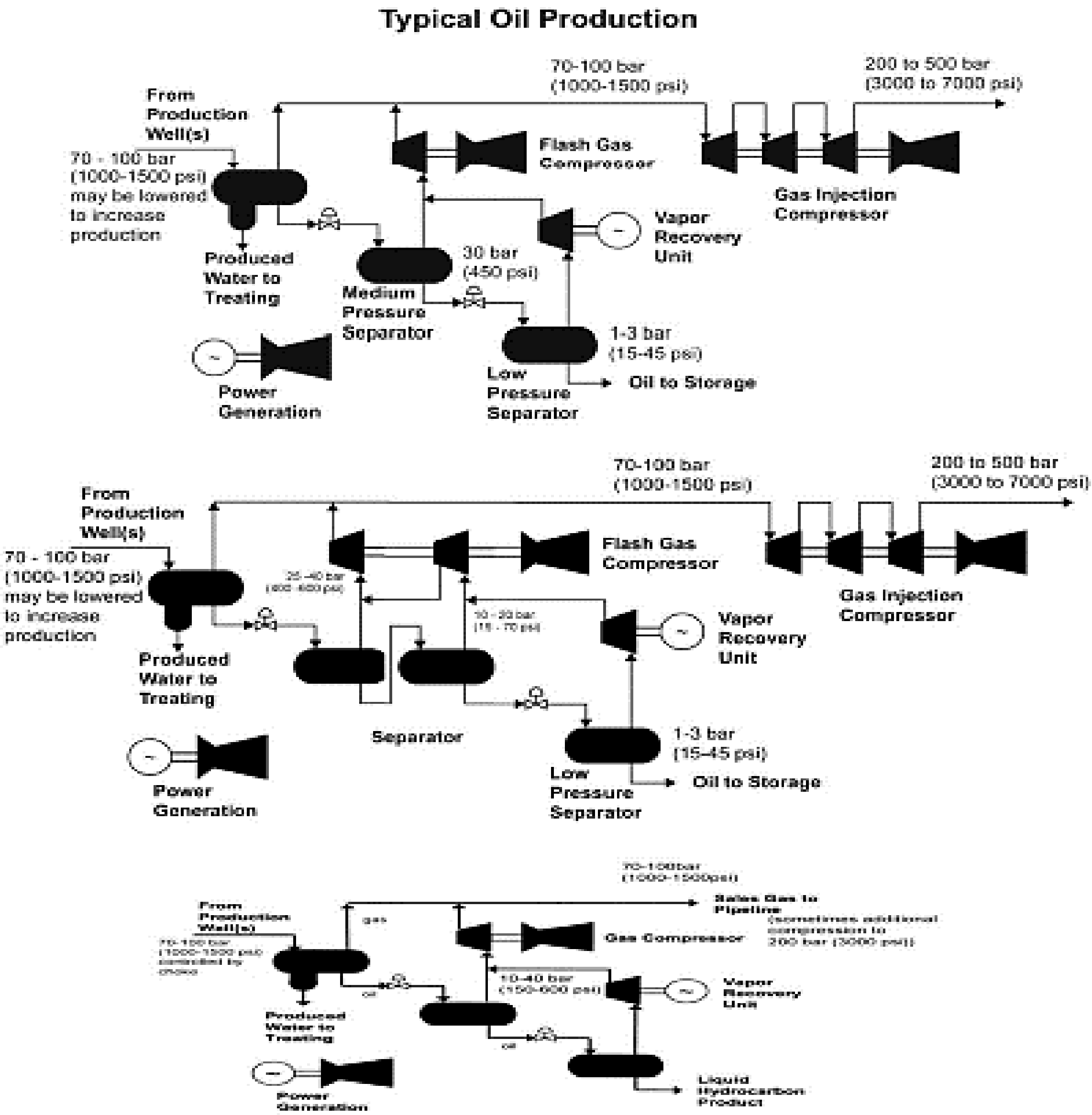


Figure 15 showcases various functions that can be implemented in offshore oil fields, including gas gathering, crude stabilization, gas injection, and gas export. These functions play important roles in optimizing the overall operations and productivity of the oil fields located offshore

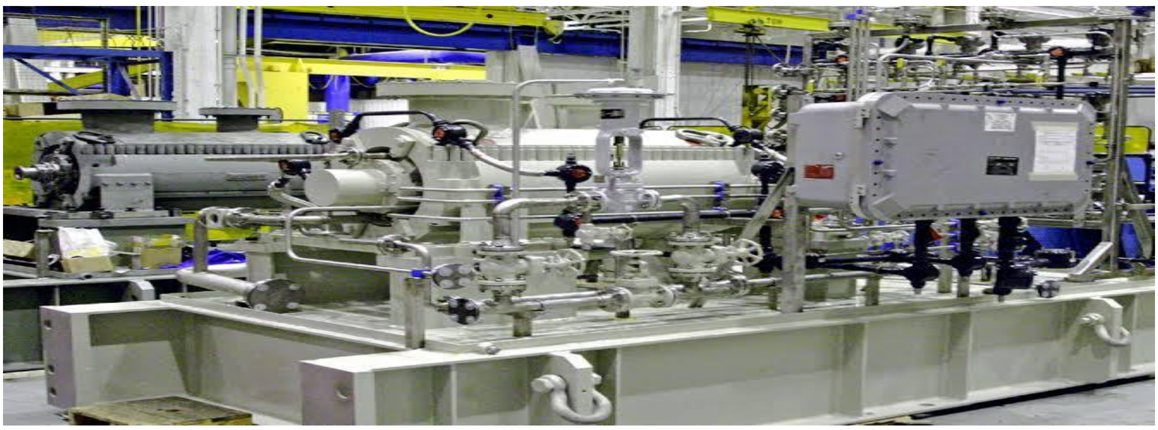


Figure 16. Train of Gas Compressors for Use Abroad.

The Accumulation of Gas in Gas Fields In this use case, compressed gas from gas wells is sent to a processing facility or pipeline. One or more "flow lines" connect each well in a region to a single or several booster compressors at an intake compression station. It is common practice to treat the compressed gas further so that it is of marketable quality before selling it. The compressor station is upstream of the gas plant and often located near the wellhead. Gas is often sourced from a number of wells, all of which may have varying pressures at the time of production. Typically, the gas is compressed to around 70–100 bar (1000–1500 psi) while the suction pressures in the applications range from 3–20 bar (50–300 psi). In a typical setup, smaller compressors near the wellhead feed into bigger compressor stations placed in the centre of the field. The dynamics of the reservoirs determine the inflow pressures. The initial ratio and flow rate of a gas collection system are typically low (in the 1.25 to 1.5 range) and high, respectively. In most cases, the reservoirs' production capacity decreases with age, necessitating lower pressures to keep volume rates constant. Eventually, the losses in the collecting system's well tubing and flow line pipework will outweigh the benefits of any further compression.
• Fundamental Differentiation • Initial Compression (boost compression, input compression) • Elimination of Carbon Dioxide • Removal of Mercury and Chloride • Dehydration of Gas • Gas Expansion using Turbo-Expander • Fractionation of LPG/Condensate • Compression of Dry (Sales) Gas • Storage • Utility Systems this provides a more advanced and clear understanding of the various phases depicted in Figure 18.

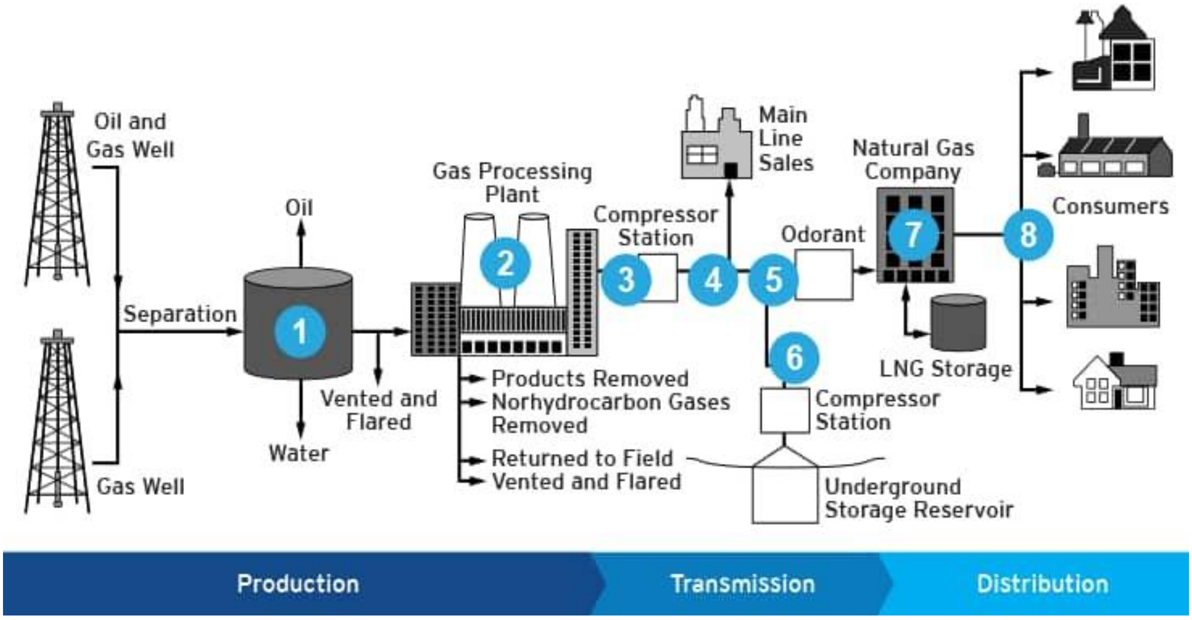


Figure 17. Gas Plant.

In a gas plant, there are multiple compression tasks that need to be carried out. One of these tasks is the compression of gas at the plant's intake, specifically at the boost compressor. This is done to increase the pressure of the gas from its delivery pressure at the gas collection system. Another important compression task in a gas plant is the use of a re-compressor, also known as a sales gas compressor. This compressor is employed to reduce the pressure of the natural gas from the power plant to meet the standards required for pipeline transportation. Depending on whether the responsibility lies with the gas plant or the pipeline operator, this function may also be referred to as the pipeline head station. These compression processes play a vital role in optimizing gas transportation and ensuring the gas meets the necessary pressure requirements for different stages of the production and distribution process.

Figure 18. Compressor for export

Gas Lift

An example of this is shown in Figures 19 and 20, which depict an application of gas injection into an oil well to aerate the crude, hence increasing the flow of crude to the surface. The process might also be integrated with gas collection. It is common practice for certain companies to use the same compressor train for both gas lift service feeding and gas pipeline export compression.

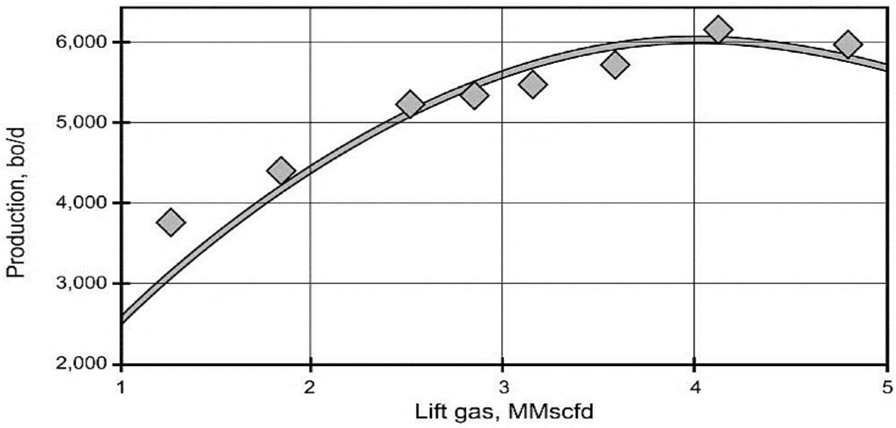


Figure 20: Gas Lift Affects Production.

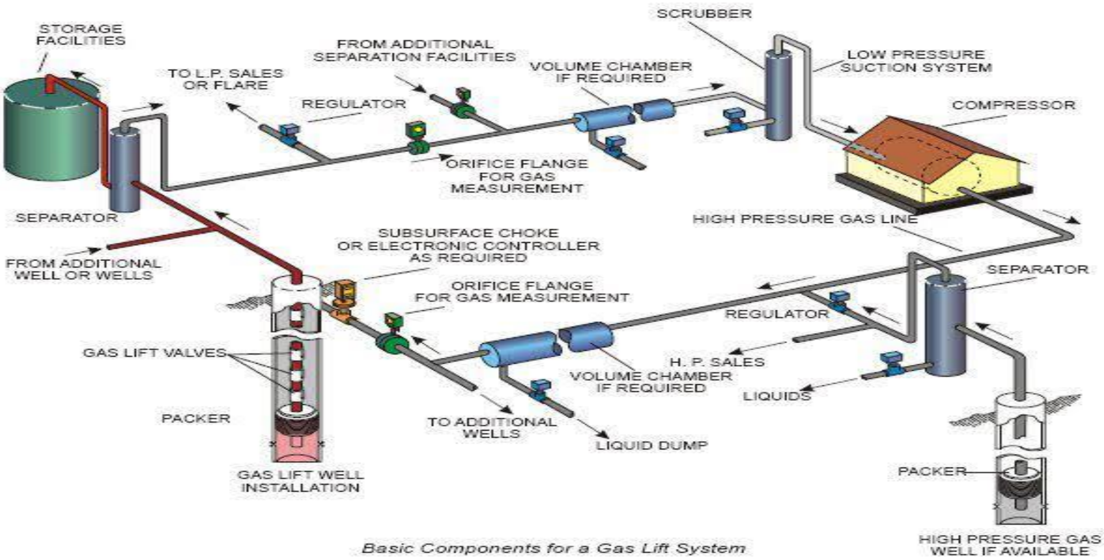


Figure 21: Gas Lift

It may be necessary to utilize a "gas lift" to artificially raise a well. Produced gas has been compressed to a greater pressure (from 3 to 7 bar, or 50 to 100 psi) before being reintroduced into the tubing at a set depth below the well casing via a gas lift valve. In most cases, the discharge pressure of a compressor will be in the range of 100 to 120 bar (1400 to 1700 psi), but in extreme cases, it may need to reach up to 200 bar (2900 psi), in which case, compressors with a reasonably high output and a high compression ratio will be necessary.

The Re-injection of Gas
As a kind of EOR, re-injection is used to restore the appropriate level for manufacturing and stimulate the recovery of extra crude oil in oil fields where output has naturally declined over time. The field's exploitation rate can be raised by as much as 20% with the use of this method. Re-injected gas is typically the associated gas recovered during the flash and stabilization phases after being cut off from the crude oil. It is also possible to employ additional gases, such as nitrogen or carbon dioxide. By re-injecting the gas into the reservoir through specially drilled wells, oil is pushed in the direction of the well bores. Carbon dioxide (CO2) or nitrogen (N2) may also be injected into the reservoir as part of a gas injection project. Compressors with discharge pressures of 140 to 820 bar (2000 to 12,000 psi) are often needed for deep reservoirs (Figure 16). Recent developments in material technology have made it possible to re-inject related sour gases with high concentrations of H2S and/or CO2 without first sweetening them.

Underwater Compression
Platforms (preserved leg for shallow waters, and floating for deeper oceans) are used to deploy the aforementioned services for offshore applications. It is possible that these facilities might be situated on the ocean floor. There are currently no subsea compressors in commercial production, and developing subsea compressor packages is a major issue. The design of the compressor's motor and drive systems to withstand long periods of time on the seafloor is another difficulty, as is the problem of separating gas solids from liquids close to the well (or, alternatively, the capacity of the compressor's ability to compress gas with substantial quantities of entrained liquids).
Midstream Applications

Pipeline Compression
Compression is also often used in long-distance transmission networks. Booster compression, in which pressure is increased at regular intervals to counteract pressure decrease produced by friction in the pipeline, is necessary for many pipelines. Pipelines may carry natural gas across long distances. The optimal pipeline pressure ranges from 40 to 160 bar (600 psi to 2500 psi), depending on the pipeline's length and the price of steel, to strike a happy medium between the energy needed to pump the gas and the cost of the pipe itself. Pipelines that span many countries typically run at pressures of between 60 and 100 bar (1000 and 1500 psi), however some older systems may function at lower levels. Compressing the gas (often from a gas plant) to pipeline pressure is typically done at a head station. Pressure ratios of 3 are not uncommon at this control point. Compressors in a pipeline are typically located every 1.2–1.8 miles along the pipeline to maintain a constant pressure ratio. Mainline stations are those that are always on, whereas booster stations are those that are only on sometimes to help mainline compression.

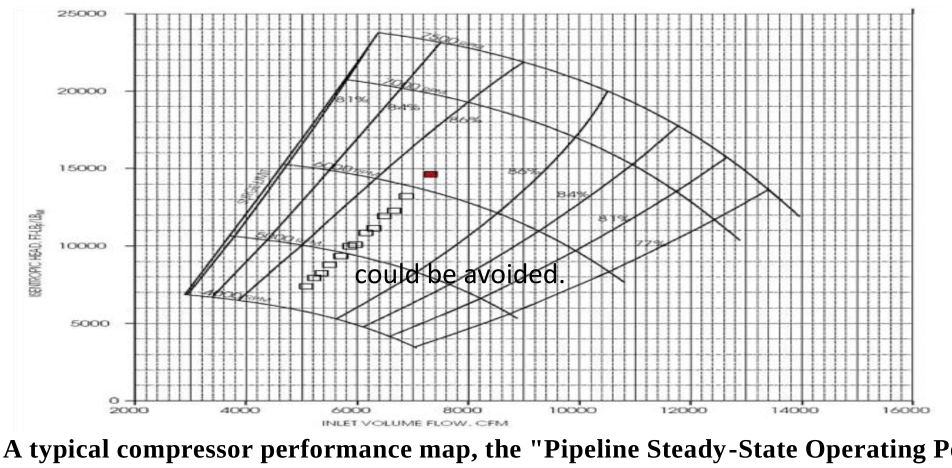


Figure 22: A typical compressor performance map, the "Pipeline Steady-State Operating Points" refer to specific operating conditions of the pipeline

These points represent the various combinations of gas flow rate and discharge pressure that the compressor system encounters during steady-state operation. Typically, a compressor performance map visualizes the compressor's performance characteristics, such as efficiency, pressure ratio, and flow rate, at varying operating conditions. By plotting the pipeline's steady-state operating points onto this map, it allows for an assessment of how well the compressor system matches the requirements of the pipeline. The operating points on the map represent the intersection between the compressor's capabilities and the pipeline's demands. This analysis helps evaluate the compressor's efficiency, determine its operating range, and ensure that it is operating within safe and efficient parameters. By studying the relationship between the pipeline's steady-state operating points and the compressor performance map, engineers can make informed decisions about compressor selection, optimization, and maintenance to ensure reliable and efficient operation of the pipeline system.

Having "power" backup instead of "unit" standby on a station is an idea that has been floated from time to time. The plan is to use an enormous driver that is only partially loaded during normal operation, eliminating the need for a second unit to serve as a backup. In this situation, the driver has to be large enough to work in tandem with other (equally huge) units farther down the pipeline to cover for a downed upstream station. One benefit of this idea is that fewer physical objects are required. The downside is that the driver spends much of its time in part-load, low-efficiency operation. A station's capacity to reduce power is severely hampered by oversize units.

1. **Parallel Compressor Arrangement (Top):** - In a parallel compressor arrangement, multiple compressors operate simultaneously, sharing the workload. If one unit fails, the remaining unit(s) will need to compensate for the lost capacity. - After the failure at time = 1.0, the operating point on the graph for the parallel arrangement may show that the remaining unit(s) take on a higher load to maintain the required gas flow and discharge pressure. The operating point might shift to reflect the increased load on the functioning unit(s).

2. . **Series Compressor Arrangement (Bottom):** - In a series compressor arrangement, multiple compressor stages are connected in a sequential manner. If one unit fails, the remaining unit(s) continue the compression process. - After the failure at time = 1.0, the operating point on the graph for the series arrangement may show that the remaining unit(s) continue to operate, but with a reduced capacity for gas flow and discharge pressure. The operating point might shift to reflect the reduced capacity due to the loss of one compressor unit. The specific details of Figure 26 and the behavior of the operating points would depend on the specific characteristics of the compressors, the system design, and the impact of the failed unit on the overall performance of the arrangement

Capturing and Releasing Gas

The United States and Canada built their first underground gas storage tanks in the early 20th century. They served as a source of natural gas for homes in the area to utilize for heating in the colder months. This was required as the local pipeline and production facilities sometimes couldn't keep up with the soaring wintertime demand. The need for gas storage facilities has expanded since the emergence of a gas spot market in the mid-1980s. There are already more than 400 operational facilities in North America and more than 130 in Europe. Most of these gas storage facilities utilize previously used aquifers, salt caverns, or depleted hydrocarbon resources (INGAA, 2007). Storing in layers of porous rock is used for the first two methods, while a hollow is formed by washing away a portion of a salt dome for the third. These storage facilities eliminate the risk of leaks and other accidents. When demand is low, the pipeline firm will pump natural gas into the storage field, and vice versa when demand is high (Figure 27).

In the past, people relied on storage to meet their increased demands throughout the winter. Historically, winter is when natural gas use is highest because of heating needs in homes. However, in recent years, demand has become less seasonal, mostly as a result of growing demand from natural gas fuelled power plants. This change highlights the growing significance of strategically located natural gas storage facilities to the natural gas industry.

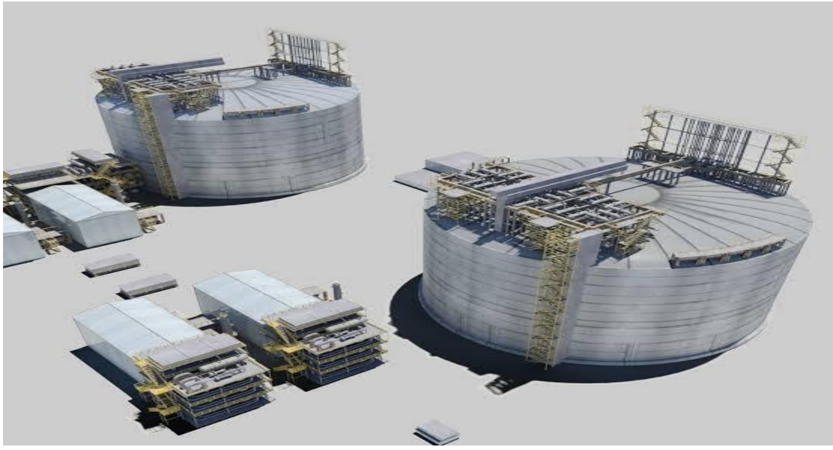


Figure 23. Gas Storage

- By keeping production and pipeline flow roughly constant, storage can lessen the demand for swing natural gas supply deliver-ability and pipeline capacity. • Customers can employ storage to lower their pipeline demand costs, protect themselves against an increase in the price of natural gas, or take advantage of pricing differentials in the gas market.
- Storage allows for operational flexibility and dependability for pipelines and local distributors by offering a destination for excess gas supplies or a supply of gas to fulfil unforeseen gas demand. In addition to balancing, parking, and borrowing services, market trading hub storage facilities also high demand or low supply. This allows for a more balanced and reliable supply of gas to power plants and other consumers. To address the varying daily and hourly power plant loads, high deliverability storage facilities are necessary.

These storage facilities have the capability to quickly inject or withdraw large volumes of gas to match the fluctuating power plant demand throughout the day. This helps to ensure a consistent and reliable gas supply to meet the power plant's dynamic requirements. Additionally, expanding seasonal demands require more conventional storage facilities. These facilities are designed to store gas over longer periods, typically months or even an entire season. They are used to mitigate the impact of seasonal swings in gas supply and demand. During periods of low demand or high supply, excess gas is stored in these facilities. Then, during periods of high demand or low supply, the stored gas is released to meet the increased needs of the pipeline system. The combination of high deliverability storage and conventional storage facilities allows for efficient management of gas supply and demand fluctuations. By strategically storing and releasing gas, pipeline systems can better handle the seasonal swings and the periodic entry of liquefied natural gas, ensuring a stable and continuous supply of gas to consumers.

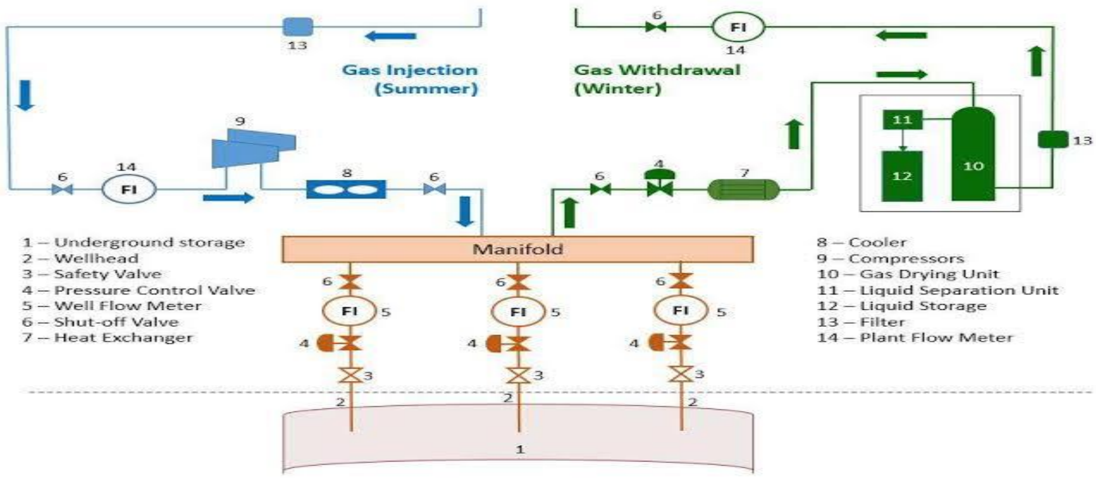


Figure 24: illustrates the series and parallel operation of compressors for gas storage purposes

Here is a general explanation of these operating modes:

1. **Series Operation:** - In series operation, multiple compressor stages are arranged sequentially, with the output of one stage feeding into the input of the next stage. - This arrangement allows for incremental compression of the gas or air, with each stage increasing the pressure until the desired storage pressure is achieved. - Series operation is beneficial when a high compression ratio is required, as each stage operates at a lower pressure ratio compared to compressing the gas in a single stage.

2. . **Parallel Operation**: - In parallel operation, multiple compressors operate simultaneously, either independently or with their outputs combined. - This arrangement allows for dividing the workload across the compressors, which can increase overall capacity and provide redundancy in case of a single compressor failure. - Parallel operation is advantageous when the demand for compressed gas or air is high, as it allows for distributing the load across multiple units, reducing the load on each individual compressor. The specific details of Figure 28 and the behavior of the compressors would depend on the specific design and requirements of the gas storage application. It's important to note that the compression of air and gas storage applications can vary in terms of operating conditions and system design.

Compressed air is essential in many chemistry operations. Ammonia factories and air purification facilities are two such examples. Compressed air has several uses in industrial and manufacturing settings, including powering machinery. It has potential for application in my ventilation. Large air compressors are also needed for air separation in some types of integrated gasification combined cycle (IGCC) power plants. Multistage machines typically powered by electric motors can be found in situations where the needed volumes make centrifugal compressors advantageous. How many impellers are used relies on the pressure ratio that must be met. The efficiency of a plant is typically a major consideration because of the effect it has on running costs. Having the capacity to supply air efficiently across a variety of flow rates is also frequently required. Since air is non-toxic and non-combustible, the seal requirement is lower than it would be for other types of compressors.

Separation of Air

Smaller quantities like carbon dioxide, neon, helium, krypton, hydrogen, xenon, along with water vapour are also present in air with the more abundant nitrogen and oxygen. Cryogenic and non-cryogenic techniques are typically used in air separation facilities to extract oxygen, nitrogen, and argon from ambient air. Physical adsorption allows oxygen and nitrogen gas products to be extracted from compressed air at temperatures close to room temperature in non-cryogenic facilities. Where output is minimal, purification is not a concern, and just one gas is needed (oxygen or nitrogen), non-cryogenic reactors might be an economically feasible choice. Liquidating and distilling ambient air, cryogenic plants can isolate its constituents. High-purity gases and liquids (such as oxygen, nitrogen, and argon) may be produced at a rapid pace in cryogenic facilities.

Compressing air is the first step in any method of separating air. If the pressure of the nitrogen or oxygen being released from the separation process is too low, more compression may be required. If the items are to be given in liquid form, further compression may be required during the chilling process.

Massive amounts of atmospheric air are first sucked in. Before going into the cryogenic equipment package, the air is compressed and filtered. Using their respective boiling points, oxygen, argon, and nitrogen are extracted from air after it has been chilled to around!300 F (!185 C). Compressing the gaseous oxygen and nitrogen allows for easier transport and subsequent utilization.

Since electric motors are typically used to power compressors, electricity is the greatest single operating cost in air separation facilities, accounting for anywhere from a third to two-thirds of total operating expenses. Therefore, the efficiency of the compressor is crucial.

CO_2 Compression

Compressing CO2 requires attention to the following critical issues:

- Due to CO2's density, its flow into the impeller will typically be slower than the speed of sound at operating speeds that are lower than the mechanical limit for the impeller's working speed. Compression applications that use heavier gases, such propane or other refrigerants, have the same problem. This also causes the head-flow characteristics of multistage compressors to be relatively steep and have a small usable operating window. In higher pressure ratio, multi-casing compression needs, a gearbox between the casings is typically advantageous due to the substantial volume decrease each step.

- We have a firm grasp of the fluid and thermal characteristics. Pure carbon dioxide's critical pressure and temperature (73.5 bara/29 C, 1066 psia/85 F) are considerably within the range of practical compression processes. Both compressibility (i.e. density) and enthalpy are highly temperature-dependent under these circumstances. Condensation would result from a decrease in temperature, but a rise in temperature would significantly reduce the effort needed. It's important to remember that CO2's thermodynamic characteristics are drastically altered by the presence of even trace amounts of other molecules.
- Carbon dioxide by itself is non-corrosive and chemically inert. However, it reacts quickly with water to generate carbonic acid, which rapidly eats away at carbon steel.

Compression of Sour Gas

In contrast to "sweet gas," the term "sour gas" is commonly used to describe natural gas that contains high concentrations of hydrogen sulphide and carbon dioxide. As mentioned up top, many gas fields provide sour gas, necessitating the removal of H2S and CO2 in the gas plant. When utilised for gas re-injection, sour gas is sometimes compressed without any pretreatment Sulphide stress cracking of materials in water is a particular problem when H2S concentrations are high.In the process of compressing sour gas, the combination of hydrogen sulfide (H2S) and carbon dioxide (CO2) with liquid water can lead to the formation of corrosive acids. This poses a challenge for equipment used in oil and natural gas production, as well as natural gas treatment plants, especially in environments with high H2S concentrations. To address this issue, ANSI/NACE MR0175 (2003) provides valuable guidance on the selection and qualification of carbon and low-alloy steels for use in such environments. This standard helps ensure that the chosen materials can withstand the corrosive effects of the acids formed, promoting the safe and efficient operation of the equipment. When it comes to selecting materials for various applications, especially when it involves withstanding corrosion, it's important to consider alloys that have excellent resistance against corrosion. Additionally, there are specific guidelines and limits set for the presence of hydrogen sulfide (H2S) in gas. These limits vary depending on the surrounding environment's pH and require careful consideration of materials if they are exceeded. In addition to corrosion resistance, another crucial factor to take into account is the alkalinity of water. This is determined by the combined levels of bicarbonate (HCO3) and sulphide (HS!) present. These levels play a significant role in determining the appropriate materials to use in order to ensure the longevity and functional integrity of the system the ionic strength of water, its temperature, and various other elements all contribute to determining the local pH value. These factors need to be taken into consideration when selecting appropriate materials to ensure they can withstand the specific conditions. Moreover, due to the high toxicity of H2S, it is crucial to exercise special care in order to prevent leakages and to detect them promptly if they do occur. This involves implementing strict safety measures and utilizing advanced detection systems to ensure the well-being of both humans and the environment.

The temperature of the air or water used to cool the condenser is what ultimately determines the condenser's internal temperature. This is the most basic description of the refrigeration process. Cascades (combining a low temperature cycle with a high temperature cycle utilising different gases) and compound processes (two-stage decompression with de-superheaters and economizers) are two examples of more complex cycles.

Liquefied Natural Gas

Natural gas is occasionally liquefied at!160 C (!256 F) so that it may be transported to markets that lack economical pipeline access. Special cryogenic ships may then transfer the LNG to storage terminals, where it can be stored and then regasified for injection into sales pipelines.

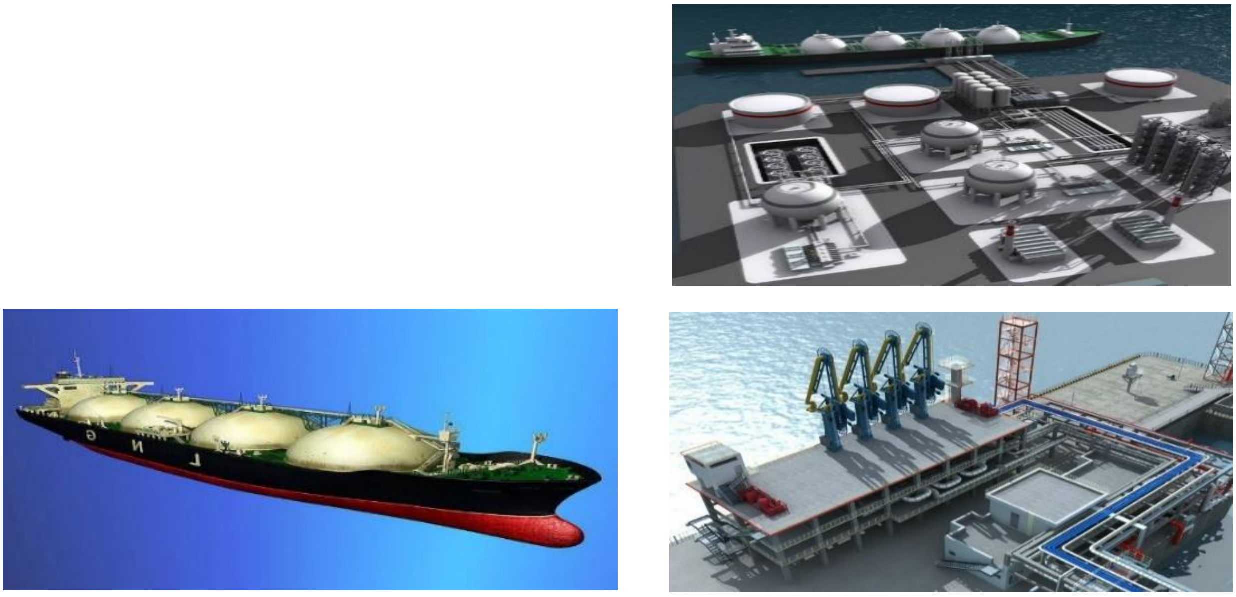


Figure 25 illustrates the journey of liquefied natural gas (LNG) from its production at the gas fields to the receiving terminal at the destination

It showcases the various stages and infrastructure involved in the transportation and distribution of LNG. The LNG stations mentioned in the figure refer to the facilities and infrastructure used at different points along the LNG supply chain. These stations include gas production facilities, liquefaction plants, storage tanks, shipping vessels, regasification terminals, and distribution networks. This comprehensive system ensures the safe and efficient transfer of LNG from its source to the receiving terminal, where it can be regasification and further distributed for various applications, such as power generation or industrial use.

All seven of the most frequent methods for cooling with LNG include substantial compression

1. Cascade: propane, ethylene, and methane refrigerant cycles
2. Single mixed refrigerant: more commonly used in peak shaving plants

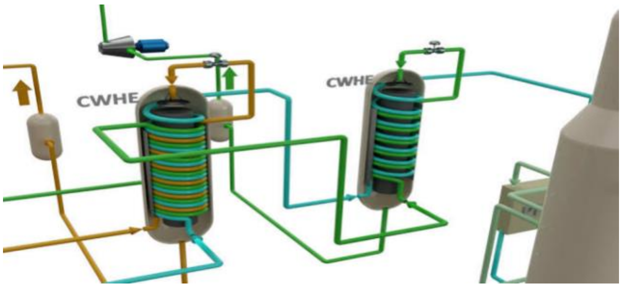


Figure 26: cascade processing plant

The Cascade LNG Process is a method used in the liquefaction of natural gas (LNG). It involves a series of multiple refrigeration cycles, known as cascades, that work in a sequential manner to achieve cycles with different operates at a higher used in this stage is goes through a heat mperature stage. This erant, until the desired ent and cost-effective cool down the natural s, making it easier to

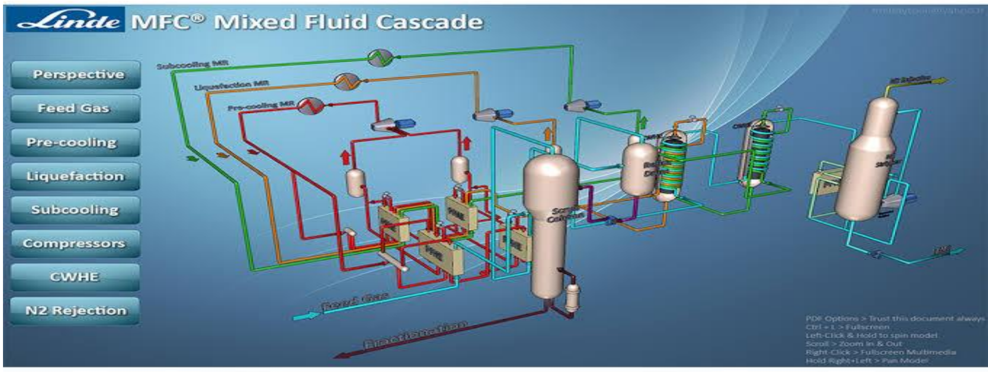


Figure 27: The Propane Mixe]d Refrigerant LNG Process is a method used in the liquefaction of natural gas (LNG)

It involves the use of a mixed refrigerant, with propane being one of the key components. This process utilizes a series of compressors, heat exchangers, and other equipment to cool and condense the natural gas into a liquid state. The propane mixed refrigerant acts as a medium for heat exchange, facilitating the cooling of the natural gas. By carefully controlling the temperature and pressure, the natural gas is cooled below its boiling point, resulting in the conversion of most of the gas into a liquid form. This LNG production process enables the transportation and storage of natural gas in a more compact and practical manner, allowing for easier distribution and utilization.

Figure 28: Large LNG Refrigerant Impeller and Mixed Refrigerant Barrel Compressor

Here, the authors briefly explore two applications to demonstrate why it's crucial to understand the application in order to pose the proper questions.

The need of thorough questioning was demonstrated on an onshore gas depleted compressing application. The falling pressure in the gas reservoir necessitated this well boosting effort in order to maintain a sufficient production rate. For this purpose, the highest achievable level of compression within the available deck area of the platform was required. For an initial output of 900,000 Nm3/d (350 MMscfd) at a suction tension of 55 bar (800 psi) and an output pressure of 80 bar (1150 psi), a total of three sets of gas turbine-driven centrifugal compressors would fit. When asked what the highest operating pressure of the sales gas line was, the operations team replied "91 bar (1320 psi)." The line may be safely maintained at this pressure; however, it is capped at 1150 psi (80 bar) due to the facility's pipeline regulations. The compressors were set up to produce a release of 91 bar (1320 psi), but were restricted to producing no more than 80 bar (1150 psi) at any given time. Because of the compressors' optimization for greater head than was necessary, production dropped, as seen in the following diagram. They used all the available energy; thus, they ran at greater flows than optimal. As reservoir pressures dropped, this problem decreased the time for restaging, which accelerated expenses while yielding less reserves, having a negative effect on economics.

A second example: Two gas turbine powered compressors were sized for a 55 bar (800 psia) suction pressure and an 83 bar (1200 psia) discharge pressure for an onshore pipeline application. Two parallel single-stage pipeline compressors would be all that's needed to get the job done. Eventually, a compressor would be installed at the station in order to expand the pipeline's capacity. Suction pressure dropped as flow increased, whereas pressure at the outlet rose. This led to two complications: Each compressor now has two impellers due to the higher-pressure ratio, and the actual rate of flow has decreased. While a restage would have allowed for the decreased flow, the increased head demand necessitated the use of two impellers rather than one. One alternative was to utilize the new compressor as a booster, with the two older compressors feeding into it, but this was ruled out because of the poor aerodynamic fit.

Since the current compressors were beam style machines with a wide enough bearing span to support two impellers, the decision was made to set up three similar units in tandem.

The takeaway is that it's not enough to think about how things will work when they first start up; planners must also factor in room for growth and change.

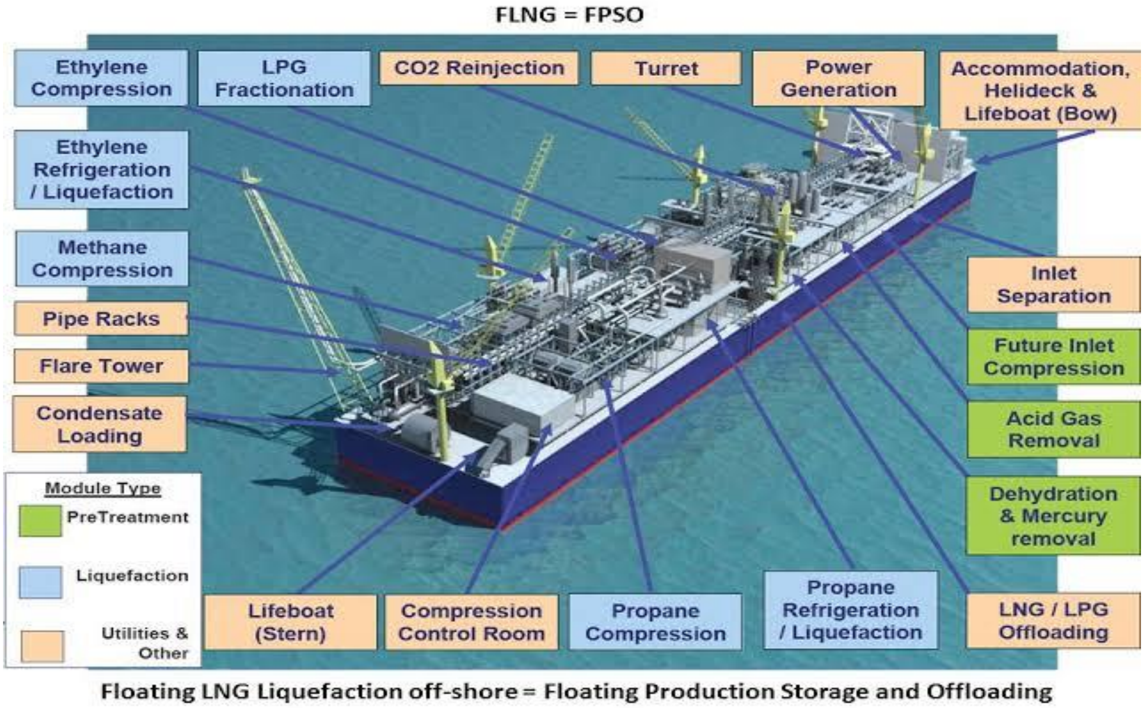


Figure 29: Floating LNG Liquefaction off-shore = Floating Production Storage and Offloading

Conclusion

In conclusion, this article has provided a comprehensive overview of the applications of centrifugal compressors, focusing on both upstream and midstream sectors. Various examples such as LNG compression, refrigeration, pipeline compression, gas injection, gas lift, gas gathering, export compression, and air compression were discussed, highlighting the versatility of centrifugal compressors across different industries. To lay the groundwork for this discussion, the theory of compression was examined, shedding light on the fundamental principles behind the functioning of centrifugal compressors. Additionally, the article outlined the typical components and configurations of centrifugal compressors, providing a holistic understanding of their inner workings. By presenting a wide range of applications and delving into the technical aspects, this article offers valuable insights for professionals and enthusiasts alike. It serves as a reliable resource for those seeking a comprehensive understanding of centrifugal compressor applications and their underlying theory.

Furthermore, this article delved into the important topics of compressor performance characteristics and control options, considering their significance in the overall functioning of the compression system and their direct impact on specific applications. By examining the interaction between the compressor and the overall compression system, readers gained valuable insights into optimizing performance and achieving desired outcomes. Moreover, the article shed light on the challenges posed by different process gases, providing specific examples to illustrate the complexities involved. By exploring these challenges, the authors aimed to equip readers with a deeper understanding of the intricacies associated with the selection and operation of centrifugal compressors for various applications.

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The Authors declare that they have no conflict of interest.

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The first author wrote the draft under the guidance of the second author on the theme and content of the paper.

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