

OVERVIEW OF NATURAL GAS COMPRESSION OPTIONS IN UPSTREAM AND MIDSTREAM OPERATIONS

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ABSTRACT

Compression is one of the most expensive parts of upstream oil and gas production, and this is also the case in midstream operations. Producers are more frequently forced to use gas reinjection in the field due to limited access to pipelines and pipeline capacity. Hydrocarbon vapor recovery units (VRUs) are also becoming a more significant part of a producer's compression fleet as other alternatives for VOC control such as flares become more restricted by environmental regulations.

Compression equipment is expensive and power requirements are significant. Expensive assets can become stranded in areas with declining production, so careful planning is required to make good use of these capital investments year in and year out. Many factors must be considered on a case-by-case basis including capital costs, operating costs, maintenance requirements, suction flow rate on a volumetric and mass basis, discharge pressure, turndown requirements, and driver options including electric motors, gas-fired engines, and even gas turbines. Hydrocarbon liquid streams are generated by multiple compression and cooling steps and while these liquids can generate additional revenue, a careful plan for the management and disposition of these liquid products is needed for reliable and economic operations. Locations for this equipment are often remote and receive limited operator attention.

Ask five engineers the best way to handle a natural gas compression requirement and you are likely to get five different answers. This paper will provide a broad overview of types of compression equipment often selected for these applications including screw compressors, reciprocating compressors, and centrifugal compressors. The pros and cons of various types of compression equipment, and a summary of the factors that must be considered to select the optimal compression approach for each set of unique gas conditioning operating conditions will be presented.

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Introduction

Gas compression is an integral feature of upstream and midstream gas recovery, transport, and processing. Compression applications vary across a wide range of suction and discharge pressures, compression ratio, volumetric flow rate, and type of gas being compressed. Applications include compression of the untreated gas for gathering and transport to treatment plants, compression as part of treatment processes, compression for environmental compliance, and compression for transport of the gas products to market. Despite the wide variety of compression applications, three main types of compressors are often selected for these applications in the upstream and midstream industries. These are reciprocating, oil-flooded screw, and centrifugal compressors.

These three compressor types are preferred for many reasons, some of them specific to the compressor type and the application, and some of them related to other practical concerns such as location, availability of utilities, maintenance, etc. This paper provides an overview of these three compressor types, describing how they work, where they are most often applied and, and what their key features, advantages, and disadvantages are. There are, of course, other compressor types that are used in the gas industry – e.g., rotary vane and lobe, liquid ring, and diaphragm; however, this paper focuses on these three compressor types due to their prevalence in the industry.

Reciprocating Compressors

General Description

Reciprocating compressors are the backbone of the gas treating industry and are widely used in several different settings within the industry. Reciprocating compressors are positive displacement compressors and can have one stage of compression or multiple stages of compression depending upon the compression ratio required. Compression in a reciprocating compressor takes place in one or more cylinders that enclose a piston that moves back and forth as the main crankshaft rotates. Cylinders can be mounted vertically but are more commonly mounted horizontally in a balanced-opposed configuration, where a cylinder (or throw) on one side of the machine is countered by a cylinder on the opposite side of the machine. The opposing throws are out of phase with each other so that on each piston stroke, the forces on the crankshaft are approximately balanced. Figure 1 shows a basic diagram of a reciprocating compressor cylinder.

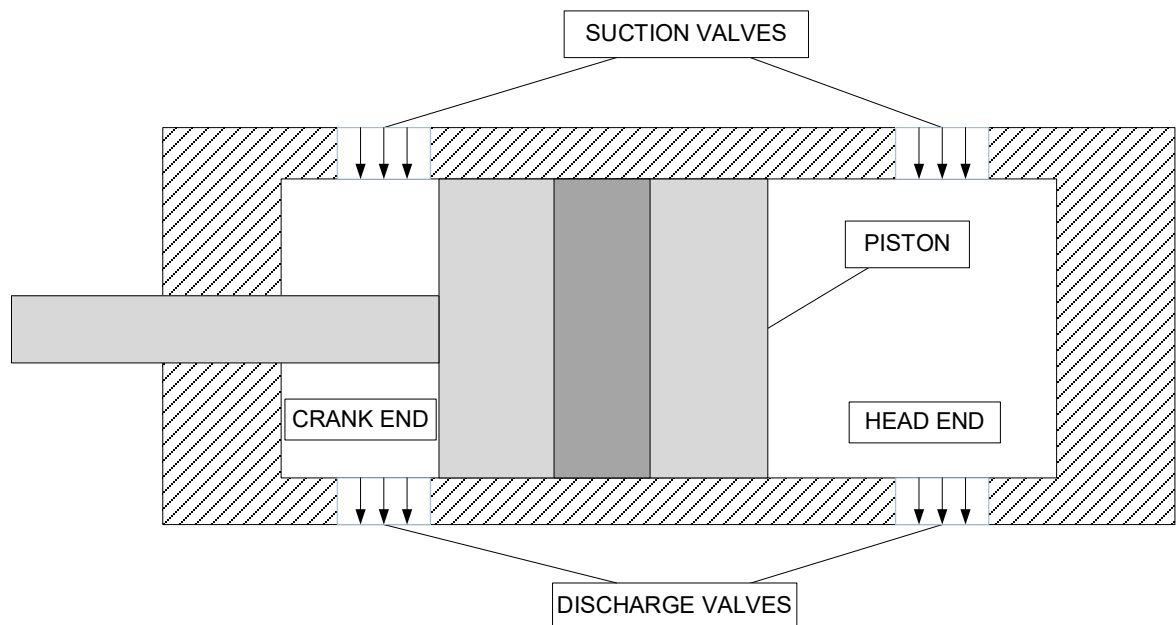


Figure 1. Basic Diagram of Reciprocating Compressor Cylinder.

Each time the main crankshaft of the compressor rotates, the piston in Figure 1 moves forward and then backward. As the piston moves forwards towards the end of the cylinder, the volume of the space in the head end decreases, and the gas in the head end compresses. At some point as the piston continues to move forward, the gas pressure in the head end of the cylinder is greater than the pressure downstream of the discharge valves and the discharge valves open. Gas flows from the cylinder through the discharge valves into downstream equipment.

At the end of the compression stroke of the head end of the cylinder, the piston has traveled almost all the way to the end of the cylinder, and the remaining volume in the head end is small. As the crankshaft continues to rotate, the piston begins to move backwards, increasing the volume in the head end. This reduces the gas pressure in the head end of the cylinder, and eventually the gas pressure in the cylinder is lower than the pressure in the upstream equipment and the suction valves open. Gas flows from the upstream equipment through the suction valves and into the cylinder.

The crank end side of the cylinder operates in an identical fashion to the head end side, but when gas compression is occurring on the head end side of the cylinder, gas expansion is occurring on the crank end side of the cylinder. In other words, the cylinder is “double-acting” and most reciprocating compressors in the natural gas treating industry are double-acting, balanced-opposed compressors. Reciprocating compressor valves are essentially check valves and come in a variety of styles. Valves are a critical wear part in a reciprocating compressor, and open/close as many times per minute as the crankshaft rotates.

The capacity of a reciprocating compressor is directly proportional to:

- The rotational speed of the compressor,
- The number and size of the cylinders on the compressor,
- The stroke length of the compressor, and

- The density of the gas to be compressed at the inlet temperature and pressure of the compressor.

The size of a reciprocating compressor will depend upon the number of cylinders needed to accomplish the required gas compression, which is determined by two major factors:

1. The rise in pressure that the reciprocating compressor must accomplish. The pressure rise across the compressor, or compression ratio (discharge pressure: suction pressure) will determine the number of stages of compression required in the reciprocating compressor. Reciprocating compressor stages are generally limited to a compression ratio of three; at ratios higher than this, the force on the piston rod during the compression stroke may be too high and exceed the manufacturer's design or the discharge temperature will exceed manufacturer's recommended maximum temperatures (often 350 °F).
2. The volume of gas to be compressed by the reciprocating compressor. Engineers in the gas industry often work in mass or molar flow rates, but a reciprocating compressor is a volumetric machine. For every compression stroke, a given volume of gas is compressed. As a result, reciprocating compressors may require multiple large bore cylinders per stage of compression for low suction pressure applications and only be able to compress a relatively small mass or molar amount of gas. A multistage centrifugal blower is sometimes added upstream to increase the mass throughput capacity in the reciprocating compressor. This generally has the effect of increasing the inlet pressure helping the compression ratio identified in #1 above.

Figure 2 is a photograph of a reciprocating compressor installed in the field. This compressor is a four stage, six-cylinder reciprocating compressor. The first stage is the three cylinders on the side of the compressor furthest away from the reader, while the second stage is the largest cylinder on the side of the compressor closest to the reader. Third and Fourth stage cylinders are on the same side as the second stage.

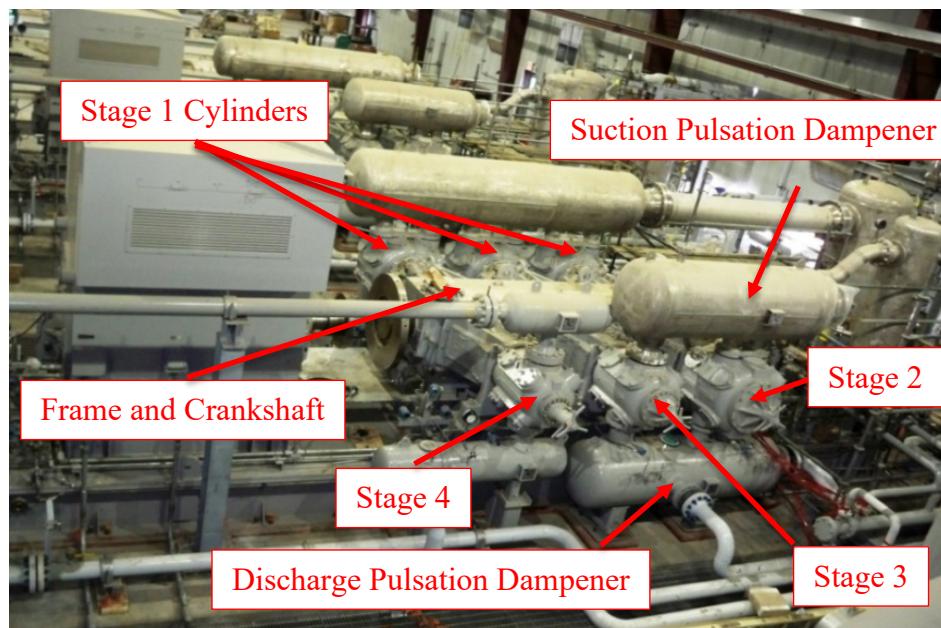


Figure 2. Example Reciprocating Compressor.

Figure 2 illustrates the point about the volumetric nature of reciprocating compressors; the first stage of compression at the lowest inlet pressure requires the three largest cylinders on the compressor to compress the large volume of gas. For the second stage of the compressor, only one large cylinder is required, and at the last stage of compression only one small bore cylinder is required. The second and third stage cylinders appear to share the same suction and discharge pulsation dampener, but an internal dividing wall is in each dampener to separate the stages from one another. The overall footprint for this compressor, including the electric motor and interstage coolers was approximately 100' long by 20' wide (30.5 m x 6.1 m). The compressor capacity was 12.5 MMSCFD (14,740 Nm³/hr) compressing carbon dioxide gas from 15-1,400 psig (1 – 97 bar(g)).

Figure 3 shows another reciprocating compressor installed in the field, but this compressor has significantly less capacity than the compressor in Figure 2. In Figure 3, the compressor is a four stage, four-cylinder reciprocating compressor. Stage 1 and 2 are the cylinders facing the reader while stages 3 and 4 are on the opposite side of the compressor.

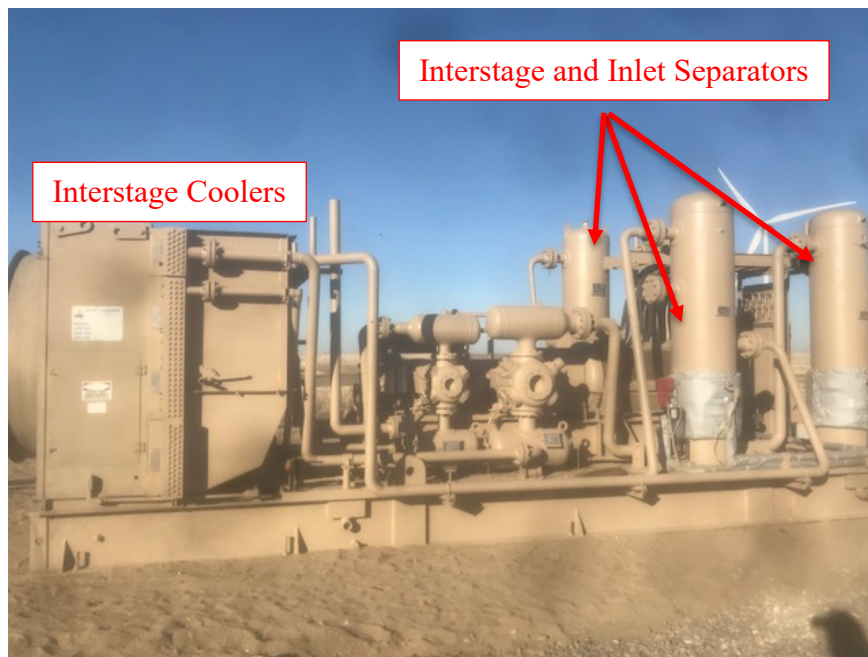


Figure 3. Example Reciprocating Compressor.

The reciprocating compressor in Figure 3 is a good example of the flexibility of reciprocating compressors. This compressor was originally designed to compress sales quality natural gas from 80-4,500 psig (5.5 – 310.3 bar(g)) to fill natural gas vehicles and was re-purposed to compress rich production gas from 50-3,500 psig (3.4 – 241.4 bar(g)) for injection back into a producing oil formation. The original design flow rate of 2.5 MMSCFD (2,948 Nm³/hr) was reduced to 1.5 MMSCFD (1,769 Nm³/hr) after re-purposing the compressor. The original compressor also had tandem cylinders installed as shown in Figure 4. Tandem cylinders may be used for high pressure applications when more stages of compression are required than there are available throws. In this instance, a four-throw compressor became a five stage compressor with the addition of the tandem cylinders.



Figure 4. Example Tandem Cylinders on Reciprocating Compressor.

The changes required to make the compressor suitable for rich gas compression were minimal. New interstage separators were required since the rich gas had some condensation occur between stages. The overall footprint for this compressor, including the electric motor and interstage coolers was approximately 35' long by 12' (10.7 m x 3.7 m) wide.

Reciprocating compressors have been in the gas gathering and treating industry since its inception and are the most common compressor type found. As a result, they are found in almost every application in the gas industry even as other compression technologies have begun to supplant them in some applications. A good example of this is oil flooded screw compressors used in refrigeration systems in gas processing. Older facilities generally have reciprocating compressors in this service.

Gas gathering systems frequently use reciprocating compressors and they are also usually found in plant feed compression, residue gas compression, and pipeline gas compression applications.

Slow and Moderate Speed Reciprocating Compressors

Reciprocating compressors in the gas treating industry can be separated into two different types: low speed and moderate speed. There are other types of reciprocating compressor, such as non-lubricated, vertical, integral, submerged, etc., but the most common reciprocating compressors in the gas treating industry will be classified according to the rotational speed.

Low speed reciprocating compressors have a slow rotational speed (defined as speeds between 200-700 RPM while moderate speed is defined as 600-1800 RPM¹), potentially a larger number of cylinders or throws, larger cylinder bores, and longer cylinder stroke lengths compared to moderate speed units. Table 1 shows the effect these differences have on the overall cost, footprint, and portability of the compressors.

¹ Engineering Data Book, FPS Version Vol. 1 Section 13. GPA Midstream Association, 2016.

Table 1. Capital Cost and Operating Power Differences for Low and Moderate Speed Reciprocating Compressors.

Parameter	Low Speed Reciprocating Compressor	Moderate Speed Reciprocating Compressor
Footprint	Larger	Smaller
Portability	Limited	Skid-Mounted, Capable of Relocation
Capital Cost	Higher	Lower
Efficiency	Higher	Lower
Preventive Maintenance Frequency	Lower	Higher

The larger footprint translates directly to increased mass of the compressor, and therefore increases the capital cost of a slow speed compressor when compared to a moderate speed compressor in an identical service. Slow speed compressors are also generally permanent residents; once set in a location they are difficult to move to a different location. This can be a large drawback in field gas applications.

Slow speed compressors will be more efficient than moderate speed compressors in an identical service due to the “valve losses” that occur on every rotation of the crankshaft. “Valve losses” is the generic term for energy losses caused by gas flow in and out of the cylinders. Some references suggest that the horsepower penalty paid for this inefficiency can be as high as 20%, although it will vary depending upon a variety of factors. The more frequent valve cycling can also lead to premature soft parts failures in moderate speed compressors, but this has been reduced over time with improved materials development. Valve type selection is a critical part of reciprocating compressor design and selection.

Reciprocating Compressors in Process Simulations

Reciprocating compressors can be accurately modeled using common process simulation software. As with any process simulation the engineer must be aware of appropriate equations of state to use for the system being modeled and the limitations of different pieces of equipment represented in the simulation. The following guidelines should also be considered when developing the simulation:

1. The compression ratio across a single stage of compression for reciprocating compressors should typically be around 3, with some exceptions. Compression ratios above this value may either exceed the manufacturer’s allowable force on the piston rod (rod load) or exceed the design discharge temperature.
2. Discharge temperatures from each stage should usually be kept under 300 °F to ensure that soft parts such as compressor valves, piston ring and rider bands, etc. do not fail prematurely. Regulating standards for reciprocating compressors set maximum discharge temperatures to 350 °F, but this temperature is considered by many operators to be too high for normal design operation or long-term continuous operation, and this limit is often used as a shutdown temperature. Some operating companies use even lower maximum temperatures: 280 °F or 275 °F. Over time, even well-maintained reciprocating compressor soft parts will wear down and gas will leak between the head and crank ends of the cylinder, through the discharge valves back into the cylinder, or out

- of the suction valves and into the upstream piping. These leaks cause compression inefficiency and will often manifest immediately as higher than expected discharge temperatures. If designed for lower discharge temperatures, the compressor can operate longer in a slightly impaired condition caused by leaking valves before needing to be shut down, which allows maintenance to be planned. Lower discharge temperatures will help wear-parts in the compressor meet or exceed their design lifetimes.
3. Pressure drop between reciprocating compressor stages can be higher than one might expect and can vary from what even compressor manufacturer software predicts. A typical multi-stage reciprocating compressor will have a compression stage followed by an interstage cooler and then a separator to remove any condensed liquids before the next stage of compression. At first glance, this would indicate a few psi of pressure drop, perhaps as much as 10 psi for the entire piping circuit and equipment between each compression stage. In practice, the pressure drop between stages may be much higher due to the pulsation dampening devices. Each rotation of the reciprocating compressor sends a pulse of gas out of the cylinders. Left unattenuated, these pulses can lead to large vibrations in the compressor and associated piping that can damage equipment, pipe supports, etc. To mitigate the vibrations pulsation dampeners and orifice plates are usually installed. A typical reciprocating compressor will have a pulsation dampener installed on the suction and discharge end of each cylinder. Inside of each pulsation dampener there might be choke tubes, orifices, or diffusers that tend to increase pressure drop between each compression stage and should be accounted for by the engineer.
 4. The efficiency of a compressor stage or the efficiency of the overall compressor can be difficult to model correctly in a process simulator. A typical generic compressor unit operation in a process simulator will allow the process engineer to input an adiabatic or polytropic efficiency value (typically on the order of 70-80%) for obtaining the expected horsepower of the compressor and discharge temperature, providing the engineer with a reasonable estimate of the compressor performance. Real-world inefficiencies such as valve losses, suction and discharge gas passage losses, and coupling slippage, will only be accounted for in the polytropic or adiabatic efficiency value used. Perhaps most importantly, the generic compressor unit operation does not tell the engineer anything about the number of cylinders required for the compressor or compressor stage. To obtain more accurate estimates of compressor performance and the actual number of cylinders required for the compression step, several compressor manufacturers offer software packages for moderate speed reciprocating compressors that can help with selection of mechanical parameters and compressor performance sheets that can then be used to improve the process simulation model.

Advantages/Disadvantages

Reciprocating compressors are found in almost every service in the gas treating industry due to their familiarity of operation and flexibility. Some advantages that reciprocating compressors have include:

1. Capability to achieve high compression ratios and high compressor discharge pressures with multiple stages (>10,000 psig). Compression ratios greater than 100 are easily achieved with multistage reciprocating compressors.
2. Reciprocating compressors can have capacity control devices installed that increase dead space in the cylinder (pocket unloaders) for limited turndown. Another turndown option

- deactivates one end of the compressor (usually the head end) and reduces the compressor's capacity to 50% of design, without reducing the overall volumetric energy efficiency of the unit. Note that additional engineering studies will need to be completed for these different capacity steps. Additional turndown below 50% may be possible on a reciprocating compressor, but this is usually done through recycling gas around the compressor, which has an efficiency (energy) penalty. Adding a VFD has a lower energy penalty but can have high capital costs in high horsepower applications and will require additional engineering studies similar to the capacity steps noted above. Destructive harmonic frequencies (certain VFD speed ranges) must also be avoided if a VFD is used.
3. **High flexibility in design and operation.** Reciprocating compressors can be designed for small or large flows with low or high discharge pressures. Additional stages or capacity for the compressor can be achieved by just adding another cylinder to the machine. In operation, a well-designed reciprocating compressor can tolerate relatively large changes in gas composition and inlet pressure.

Some disadvantages that reciprocating compressors have when compared to other compressor types include:

1. Extreme sensitivity to contaminants. Solid particles or liquid droplets can quickly damage soft parts in a reciprocating compressor and accelerate compressor maintenance requirements and score the cylinder walls. Corrosion can also occur if the liquid droplets contain dissolved acid gases. Large amounts of liquids carrying over into the compressor cylinder can cause catastrophic compressor damage including bent or broken piston rods, connecting rods, bent crankshafts, and cylinder damage.
2. Large compressor footprint. Reciprocating compressors will have a large footprint, especially when considering the footprint of interstage coolers and separators, and the piping to and from each compression stage. This can increase the total investment required for a reciprocating compressor system and may be a drawback if space is limited. A horizontal reciprocating compressor will need enough empty space around it for the compressor pistons to be removed from the machine during maintenance.
3. High maintenance frequency. As mentioned above, a reciprocating compressor has several soft parts that wear over time. Some parts like compressor valves or piston rings and rider bands are in direct contact with the process gas while others like wiper packing are not in contact with the process gas but still wear out over time. A reciprocating compressor will require periodic preventive maintenance throughout the year and periodic long duration overhauls; three years is a common frequency for overhauls. Packing that seals the space around the compressor piston rods will also leak over time and venting these leaks to atmosphere may be an environmental concern or a safety concern, if the gas is particularly hazardous.
4. Engineering studies. Required to properly design a reciprocating compressor system. These can include Torsional, Harmonic, and Pulsation studies.
5. Entrained lubrication in compressor discharge. Reciprocating compressors have lubrication oil injected into each compressor cylinder to minimize wear on piston rings and rider bands. Eventually, this cylinder oil will migrate to downstream equipment and can foul equipment that is sensitive to contamination. A coalescing filter may be necessary on the discharge of the compressor to mitigate oil fouling concerns.

Oil-Flooded Screw Compressors

General Description

Oil-flooded screw compressors are another type of positive-displacement compressor widely used in the gas processing industry. A simplified sketch of the internals for a typical oil-flooded screw compressor is provided in Figure 5. Screw compressors generally have two parallel screws turning in counter directions with interlocking lobes separated by gaps with tight tolerances.² The process gas is compressed as it is squeezed through the gaps between the screws. The screws are surrounded by circulating oil that serves three functions: 1) provides a seal for the gas to prevent backflow, 2) removes some of the heat of compression, and 3) provides lubrication for the rotating parts. The bulk of the oil is removed from the compressed gas in a coalescing separator directly downstream of the compressor body while the gas and oil are still hot. Effective oil separation is an important factor in the operating of oil-flooded screw compressors. Poor oil separation leads to carryover of oil in the process gas, which can lead to fouling of downstream equipment and loss of the oil. Hot oil from the separator flows to an oil cooler, which cools the oil down to a suitable temperature before the oil is injected back into the compressor. Compressed gas flows out of the top of the separator and on to downstream cooling or other further processing.

The type of oil used to flood the screw chamber is selected based on the manufacturer recommendation for the combination of process fluid properties and operating conditions. Options range from generic mineral oil (e.g. for air compressors) to specialty synthetic oils (e.g. for fluorocarbon refrigerants used for low temperature applications). The mutual solubility of the process fluid and the oil is a key factor in the selection. High solubility of the process fluid in the oil or vice versa may lead to poor separation and contamination of the oil. Highly specific oil types have been developed for different applications, and these oils can be a costly operating expense if the oil is lost through poor filtration or contaminated. Although pressure and temperature are increasing as the gas passes through the screw compressor, water and hydrocarbon dew points must be considered with respect to oil contamination. Once contaminated, the oil may cause mechanical failures in the compressor. Oil carryover with the process fluid to the downstream equipment can also lead to fouling and excessive oil makeup requirements.

Screw compressors that are operated dry (without oil as a seal fluid) also are available. Typical applications for dry screw compressors are those for which trace oil contamination of the process fluid is not acceptable (i.e., high purity systems) and/or entrainment of process liquids in the oil could lead to a dangerous condition (e.g., toxic gases like H₂S). The basic operating principles and equipment designs of dry screw compressors are similar to oil-flooded screw compressors and so are not addressed in this paper.

Oil-flooded screw compressors typically are supplied by the manufacturer on a skid that includes the body of the compressor, a drive (most often an electric motor), and the oil separation and cooling equipment. A photo of a typical skid is provided in Figure 6. The skidded package

² Oil-flooded screw compressors may have only a single screw, but this is not as common in gas processing applications.

nature of oil-flooded screw compressors lend themselves to being somewhat easily relocated to different locations if necessary, like moderate speed reciprocating compressors.

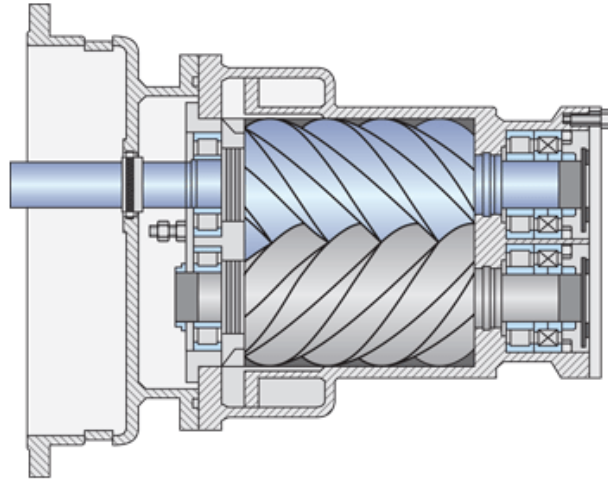


Figure 5. Typical Configuration of Screw Compressor Internals.

<https://blog.exair.com/tag/air-compressor>



Figure 6. Typical Oil-Flooded Screw Compressor Skid (Courtesy of GEA FES).

Oil-flooded screw compressors may have compression ratios as high as 20:1, higher than most other types of compressors. This is due to the oil absorbing a large fraction of the heat of compression. The oil cooling method depends on local utility availability and may use a fin-fan air cooler, a water cooler, or liquid refrigerant injection. The maximum discharge pressure for standard oil-flooded screw compressors is approximately 400 psig, which makes them an ideal candidate for processes such as natural gas boosting, vapor recovery units, or refrigeration compressors where high compression ratios, but not high compression discharge pressures are often required. Custom configurations with discharge pressures up to 600 psig or higher are available but are not as common.

Turndown for oil-flooded screw compressors typically is provided by a device known as a slide valve that effectively shortens the compression length of the screws. Turndown to less than 20% of the rated volumetric capacity is commonly possible for oil-flooded screw compressors and

does not require a VFD. Screw compressors also have fewer vibration issues or considerations than a reciprocating compressor.

Capital costs for oil-flooded screw compressors are generally lower than reciprocating compressors for an identical service application. In an example case of gas compressed from atmospheric pressure up to 150 psig, a reciprocating compressor would require a minimum of three stages of compression with the associated pulsation dampeners, interstage coolers, interstage separators, and piping associated with the compressor. An oil-flooded screw compressor in comparison is a much smaller machine for the same compression requirement, and usually represents a lower capital investment.

Typical Services

The most common applications for screw compressors in the oil and gas industry are for vapor recovery units (VRU), refrigerant compression, and instrument air compression. Screw compressors are the workhorse for refrigeration and instrument air applications and may also be used in gas gathering applications where the required discharge pressure is relatively low.

VRU service is a difficult application for any type of compressor. Vapor from storage tanks is, by definition, saturated with whatever liquid is present in the storage tanks and will usually cause liquid concerns in the vapor recovery compressor system. The gas flow rate from most storage tanks can be relatively low and highly variable. Most VRU compressors are installed to comply with environmental regulations to either limit emissions, flaring, or both. It can be difficult (though not impossible, particularly at larger sites) to offset VRU capital and operating costs with the revenue generated by the recovered gas. VRU compressors may be frequently turned on and off, loaded and unloaded, etc.

As a result, a relatively low-cost compressor that can compress a small volume of atmospheric pressure gas back up to an intermediate or feed pressure within the facility or pipeline pressure, an oil-flooded screw compressor often fills this role admirably. Although other compressor types are also used in VRU applications. The turndown with a screw compressor with a slide valve is often very advantageous in VRU applications. Figure 7 shows a small oil-flooded screw compressor in VRU service. In this case, this was one of four identical compressors installed in the same service with only two running at any given time. This allowed for the compressors to undergo the relatively frequent maintenance associated with this service while still avoiding flaring or venting any gas from the storage tanks.



Figure 7. Example VRU Screw Compressor.

Several other approaches for VRU use in natural gas processing have also been developed and used in the industry that have been the subject of other LRGCC publications but are not covered additionally in this paper.

Modeling in Process Simulation Software

Oil-flooded screw compressors are difficult if not impossible to model accurately in many of the standard process simulation software packages. Both oil and gas are being fed concurrently to the compressor and the heat of compression of the gas is distributed to both the gas and liquid phases, reducing the outlet temperature of the gas. Many process simulation software packages do not allow for the feed of an oil with the process gas to a compression module, thereby resulting in the inability to accurately model an oil-flooded screw compressor in a standard simulator compression module. A series of paired compressor stages and heat exchangers may be used to represent a screw compressor in a simulator from a heat and material balance basis, but the work calculated by the simulation software for the case may not be accurate. To accurately estimate the power requirements of a screw compressor, one of the proprietary software packages available from the screw compressor manufacturers should be used. These software packages will also estimate the required oil flow rate and duty for the oil cooler of the compressor, which has a significant cooling requirement.

Operating Power Requirements

Typical efficiencies for oil-flooded screw compressors are in the range of 40-65% (although efficiencies up to 80% are possible in some applications). The best-case brake horsepower requirement for a screw compressor is estimated to be 1,000 hp for an example case of compressing 5 MMscfd of natural gas from 14.7 psia to 120 psig. 1,200-1,300 hp may be a more realistic planning factor in case the compressor rated capacity does not line up with the most efficient operating point for the model selected. In all cases, an oil-flooded screw compressor will be less efficient than a reciprocating compressor in an identical service, but will likely have

a lower capital cost, particularly if the compression ratio required by the process is greater than what a single stage reciprocating compressor could accomplish, so long as it is within the capability of a single oil-flooded screw stage.

Maintenance Concerns

Oil-flooded screw compressors can be maintenance intensive. In some applications, such as VRU service, the feed gas may be saturated with water and/or hydrocarbons. As the gas is compressed by the screws, the pressure of the gas may approach dewpoint. In other compression technologies, the gas temperature would be rising proportionally with the pressure, but the presence of the oil reduces the temperature rise. In some cases, condensation can take place in the compressor, which can contaminate the oil. Contaminated oil may “thin out” or become an emulsion and lose the transport properties that make it a suitable lubricant, which can quickly lead to mechanical failures in the compressor. In this case, the oil must be changed out completely. This is a situation that can also occur frequently, and the specialized nature of some oil-flooded screw compressors can make an oil change very costly.

Oil vendors can provide services to sample and analyze the oil on a regular basis to check for impurities or decomposition products. Oil contamination can also be a problem in gas gathering or booster service applications.

In refrigeration service oil contamination is less likely since the refrigerant is in a closed loop system, but periodic charging of refrigerant is sometimes required in an operating plant due to maintenance activities, small leaks, etc. Plant personnel should verify that the refrigerant being charged into the system meets the purity requirements set forth in the plant design. Refrigerant systems must be thoroughly dried and evacuated after they are opened to the atmosphere or oil contamination and freezing concerns will quickly become apparent in the system. The oil filters, including the standard oil filter for particulate removal and the coalescing filters for separation of oil from the process gas, must be replaced on at set intervals or sooner if pressure drop across the filters increases.

Advantages/Disadvantages

Advantages of oil-flooded screw compressors:

- High compression ratios in a single stage due to cooling provided by injected oil
- Relatively low capital costs
- High turndown ratios without a VFD

Disadvantages of oil-flooded screw compressors:

- Higher energy requirements
- Potential for oil carryover with process gas
- Potential for accumulation of impurities and water in the oil – oil requires frequent testing and replacement in some applications
- Relatively maintenance intensive
- Limited capacity when compared with reciprocating compressors

Centrifugal Compressors

General Description

Centrifugal compressors (which are sometimes called radial compressors) are considered a type of turbo compressor. In turbo compressors, kinetic energy (or velocity) is transferred to the process gas by rotation of an impeller or rotor; the fluid accelerates as it passes through the impeller, then the fluid is carefully slowed down in the diffuser section to convert the kinetic energy into static head pressure. Figure 8 shows a typical gas flow path inside the casing of an in-line centrifugal compressor. There are several types of centrifugal compressors including integrally geared, inline/single shaft (or barrel), and axial flow compressors. Inline and integrally geared (IG) centrifugal compressors are common types of centrifugal compressors in the gas process industry and will be the focus of this paper. The focus here is on an IG compressor although many of the points (except pinion gear items) also apply to inline compressors.

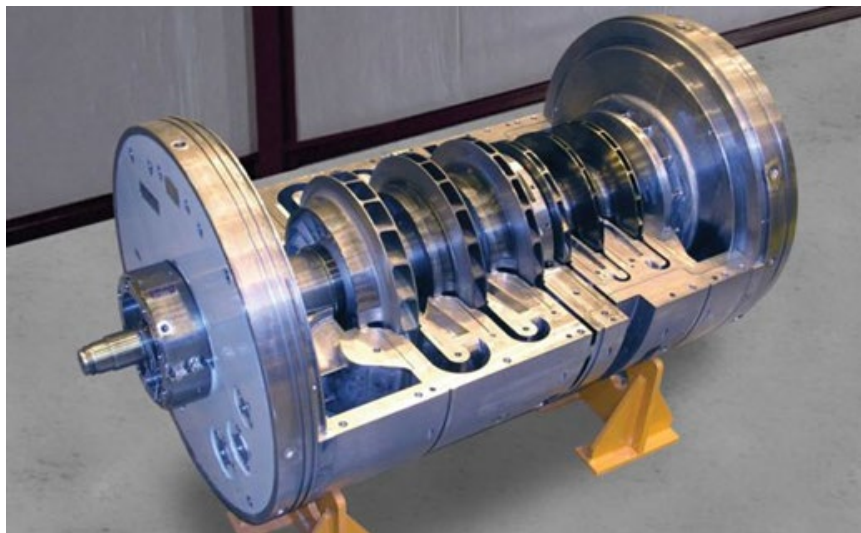


Figure 8. Fluid Flow Path in In-line Centrifugal Compressor.

<https://www.turbomachinerymag.com/types-of-centrifugal-compressor-configurations>

Multistage Centrifugal compressors are often selected for suction flow rates ranging from 100 acfm up to 100,000 acfm, with a discharge pressure as high as 10,000 psig. The maximum compression ratio in a single stage is typically in the range of 1.6 to 2.3, and external process cooling is often required between stages.

Integrally geared compressors often have multiple stages in one machine to achieve the required discharge pressure. One or more pinion gears with two impellers on each pinion gear are arranged around a centrally driven bull gear. The bull gear is driven by the main driver for the compressor, which can be an electric motor, steam turbine, or gas turbine. Figure 9 provides a schematic of a central bull gear with three shafts for a total of six compression stages (each impeller represents a compression stage). On the suction feed, the fluid enters the nozzle of the centrifugal compressor and typically flows through inlet guide vanes to the inlet of the impeller. The impeller spins on the shaft to accelerate the fluid. The fluid then flows through the outlet diffuser downstream of the impeller which gradually slows the fluid velocity to convert the

kinetic energy into pressure. The fluid flows out of the diffuser through the collector, which gathers the flow to discharge into a downstream pipe. The gas then proceeds to an interstage cooler or directly to the next stage of compression.

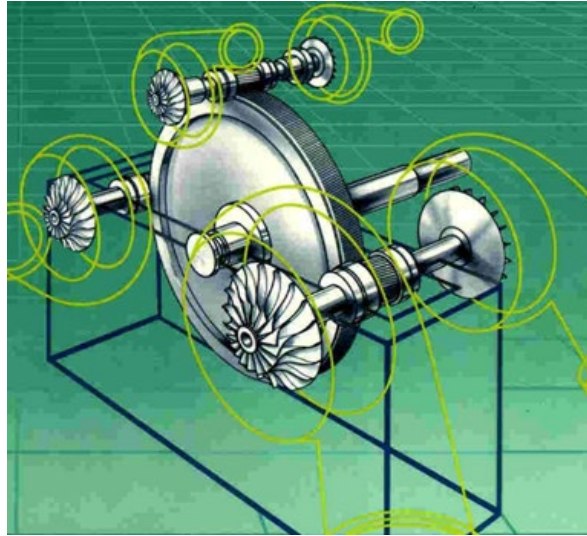


Figure 9. IG Centrifugal Centrally Driven Bull Gear with Multiple Shafts (Courtesy of MAN Energy Solutions).

Each pair of impellers on a pinion gear can be operated at a specific speed by changing the gear ratio; this enables performance efficiency optimization. Typical rotation speeds vary depending on the application and range from a few thousand rpm up to 50,000 rpm for highly specialized machines, or perhaps even higher in some applications. A lubrication oil system is required for the driver bearings and gears, but it does not contact the process gas. Figure 10 shows an IG centrifugal compressor. This compressor is a seven-stage compressor with four different pinions driven by a main bull gear. Additional stages are on the opposite side of the compressor, away from the reader. Since the compressor is a volumetric flow machine, the larger wheels will be the lower pressure stages.

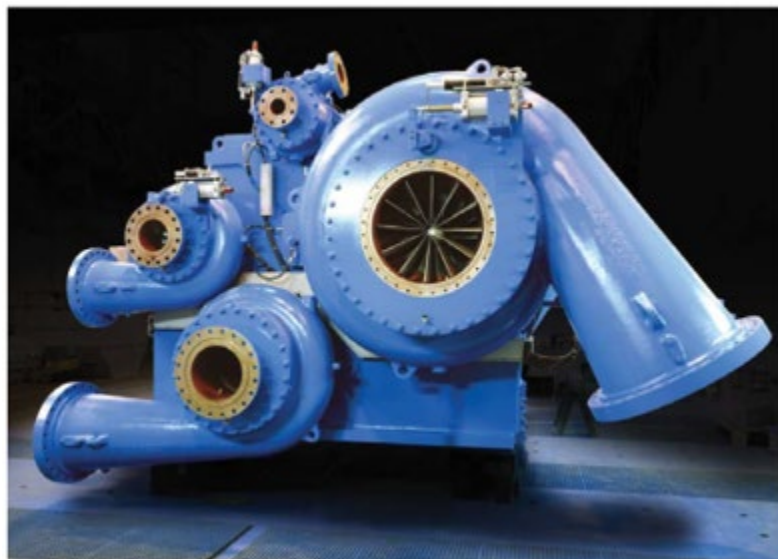


Figure 10. Example Integrally Geared Centrifugal Compressor (Courtesy of Siemens).

The turndown capability of a centrifugal compressor is typically less than a reciprocating compressor or a screw compressor. Without adding a VFD, maximum turndown without recycle is typically down to 70% of the design flow rate. The centrifugal compressor will follow a compressor curve like a fan or centrifugal pump curve that relates the differential pressure across the machine to the volumetric flow through the compressor. Flow rate turndown in constant speed centrifugal compressors is accomplished by throttling the inlet to the compressor, either with a butterfly valve or inlet guide vanes, which act to reduce the pressure of the fluid entering the compressor. In line with Boyles Law, gas density is proportional to pressure, flow capacity of the machine is reduced with lower pressure given a fixed impeller volume.

The efficiency of the machine at reduced capacity can be significantly lower than the efficiency at the design point at reduced flow volume. As the flow rate through a compressor is reduced the differential pressure across the compressor increases eventually reaching a point where the compressor can no longer overcome the pressure of the gas downstream of the compressor. In this condition, known as surge, gas from the discharge pressure will flow backwards through the compressor in rapid cycling events that can cause severe mechanical damage to the compressor. For this reason, centrifugal compressors are limited in practice to a minimum flow or maximum discharge pressure well away from the surge limit. A recycle valve is usually required to reduce the net capacity and prevent surge, although at the expense of increased power requirements.

Typical Services

Centrifugal compressors are most often selected when a high flow capacity is required. The gas to be compressed must be clean, as centrifugal compressors are not tolerant to continuous operation with liquids or particulate matter in the feed gas. Centrifugal compressors are also sensitive to changing inlet conditions; changes in inlet temperature, suction pressure, or gas composition will all have an impact on the gas density entering the compressor. This will change the compressor performance curve, which will also change the point at which the compressor enters surge. As a result, the ideal condition for centrifugal compressors is one in which the feed gas conditions are nearly constant and the flow demand for the compressor is within the normal performance curve of the compressor. Centrifugal compressors are often used for high volume product/sales gas transport applications, high-capacity refrigerant systems, and large-scale CO₂ transport. A centrifugal compressor at this size may be driven by an electric motor, but steam turbine and gas turbine driven centrifugal compressors may be found in some applications where electrical power is not available in large quantities and a different utility, such as natural gas may be more readily available. Some liquefied natural gas plants utilize gas turbine driven compressors, for example. The high capacity and complexity of centrifugal compressors mean that they typically have a long lead time, and it can be more difficult to repurpose centrifugal compressors for the reasons previously discussed.

The high capacity and complexity of these compressors also means that, on a per machine basis, they are usually the highest capital cost option of the compressors considered in this paper. In most instances, centrifugal compressors will become a capitally competitive option when multiple compressors of a different technology are required to compress the same volume of gas. Even in this instance, if the feed gas conditions will change over time, it may be more economical to install multiple reciprocating compressors to increase the compression block's flexibility. The significant lead time and limited turndown and repurposing options for

centrifugal compressors also may be considerations that outweigh the capital cost advantage enjoyed at high flow rates. One application where a small centrifugal compressor may be encountered in the gas treating industry is in dryer regeneration gas service. In this service, a small centrifugal compressor will compress a small volume of gas to flow through the regeneration equipment and dryer bed(s) in the various regeneration steps.

Modeling in Process Simulation Software

Centrifugal compressors can be modeled with reasonable accuracy using standard simulation software package compressor modules, assuming that an appropriate property package is selected. Two main factors that will impact the results are the selected efficiency and the number of compression stages with intercooling. Lacking vendor data, a good starting point for the simulation may be 70-80% polytropic efficiency with compression ratios of 1.6 to 2.3 for each stage. Intercooling is often utilized after most or all stages of compression. Some software applications even allow for specifying compressor curves in order to model performance under a range of conditions. Since centrifugal compressors are customized, highly engineered machines, the vendor should be consulted if precise power requirement estimates are needed.

Operating Power Requirements

Polytropic efficiency is often used for centrifugal compressors. Typical polytropic efficiencies for centrifugal compressors are in the range of 70% - 85%, with polytropic efficiencies approaching 90% in some applications.

Maintenance Concerns

Centrifugal compressors are relatively simple to maintain compared to other types of compressors. With routine maintenance of the gears, motors, rotors, and lubrication oil system, significant repairs and downtime can often be avoided. Well-maintained integrally geared compressors can offer well over 90% availability, with API compressors providing up to 98 – 99.5% availability. Impellers are relatively expensive, long lead items. Some operators purchase and store spare impellers in applications where maintaining uptime is critical.

Advantages/Disadvantages

Advantages of centrifugal compressors:

- High efficiency
- High reliability
- Low maintenance, very long (5 years plus) run time without service
- High capacity
- No oil in contact with the process gas
- No vibration and little harmonic concern

Disadvantages of centrifugal compressors:

- Limited compression ratio per stage
- Higher capital cost than other options
- Less turndown capability

- Sensitive to changes in gas composition and density
- Difficult to repurpose to other uses
- Long lead time and expensive to inventory critical spare parts

General Guidelines for Compressor Selection

The selection of the type of compressor for an application can be dependent upon many factors, not all of them pertaining specifically to the mechanical details of the compressor type. Other issues come into play, such as history in the company with that type of compressor, convenience of maintenance, availability, cost, etc. This section compares the different types of compressors and discusses their applicability to some common situations in gas recovery and processing.

Key Issues

Some of the key issues to be considered when specifying a type of compressor are listed below. A more detailed discussion follows.

Gas Compression Requirement:

- Volume of gas: Large volumes of gas to be compressed may favor technologies associated with higher capital cost but greater efficiency.
- Compression ratio required: The number of compression stages required to achieve a given ratio may result in capital cost differences between some technologies.
- Composition and cleanliness: Compression conditions that result in condensation of a vapor, and gases containing entrained liquids or solid particles can be problematic to most compressor types. Compressor design should anticipate the potential for forming hydrates in piping and equipment; this can occur in heat exchangers or areas where the expanding process gas cools down significantly (recycle valves for example).
- Type of application: Distinct types of compression applications found in gas processing may favor different compressor types (see Table 2).

Practical and Maintenance Issues:

- Capital and operating costs: smaller gas volumes may result in a preference for a lower-cost, lower-efficiency unit. In some applications, a screw compressor or single stage centrifugal may be installed upstream of a reciprocating compressor to boost pressure to the inlet of the reciprocating compressor.
- Location: Extremely remote locations can dictate the use of more mechanically reliable, simpler units.
- Utility Availability: For large stream and high compression ratio applications, high-power drives (often in the thousands of horsepower range) will be required. Electrical motors are usually preferred when the amount of power required is available. Field and short-term applications may opt to use gas-fired engines instead of electric motors in order to avoid the high cost of new high-voltage power supply lines, substations, transformers, etc.
- Permanence: Large processing plants usually have a long enough on-stream life such that major equipment will be specified and purchased specifically for the application and permanently installed. However, some applications have fast decline rates (~ 1 - 2 years) or relatively short project life. Rental compression skids are an important consideration

for shorter-term applications and are widely available particularly in oil and gas production areas.

- History and experience: Compressors are typically the most mechanically complex part of a processing plant, and often the most expensive. The knowledge gained over the years by maintenance and operations staff working with specific types of compressors is valuable. A company's experience and history with a specific type (and often brand) is logically a key part of the decision-making process.

Gas Compression Application

The starting point in the selection of a compressor type is often the type of application. Some important applications (mostly focusing on midstream facilities) include:

- Refrigeration, auto-refrigeration and external: Compression is widely used for refrigeration, in both external refrigeration (contained, closed loop refrigerant fluid transferring heat across exchangers) and in auto-refrigeration (compression and expansion of the process fluid, usually to condense hydrocarbon liquids or dehydrate in some cases).
- Flash gas recycle: In midstream processes, such as amine and physical solvent sweetening, flashing of rich-solvent process streams results in a small gas stream that is often compressed for recycle.
- Plant feed: Feed gas streams to processing plants are often compressed, in the plant itself, or upstream.
- Pipeline feed and boosting: Gas transfer pipelines, both processing plant feed and product gases, are often transported long distances requiring substantial compression at the originating locations and sometimes at booster stations.
- Acid gas injection: Gas treating often includes the production of an acid gas stream, which particularly in field locations, can be injected, requiring substantial compression of a challenging gas stream for environmental, safety, and operational reasons.
- CO₂ processing and reinjection: CO₂ is widely recovered, treated, and recompressed for injection into oil and gas reservoirs for enhanced oil recovery (EOR) or enhanced gas recovery (EGR).
- Vapor Recovery: Atmospheric storage tanks and intermediate pressure separators / heater-treaters often generate gas streams which must often be recompressed for recovery to limit process emissions and generate revenue (particularly at larger sites). The quality and flow rate of the gas to be compressed can vary greatly and cyclical operations are common.
- Upstream: Compression is also very important in upstream applications at the wellhead, for gas-lift, gathering systems, etc. These applications may be shorter term in some areas and may be subject more uncertainty.
- Dehydration: Used to boost gas pressure on molecular sieve regeneration.

Selection Comments

The compressor selection will depend upon different variables for different situations. A summary table comparing some of the key characteristics of the three compressor types is shown in Table 3. Some examples of rationale that may be used in selecting a compressor type are shown below.

- In a field application requiring quick implementation and a limited service time, the availability of existing skidded units, often rental, is paramount. Reciprocating units (usually medium speed) in many sizes are available. Oil-flooded screw units are also available for many applications.
- Power supply must also be part of the early decision-making process, since that will define what drives can be considered for use; a reasonable model of the compression process is essential to define the power requirements.
- Condensable components of a gas are an important consideration. Oil-flooded screw compressors should usually not be chosen if condensation can occur with compression. Since heat is usually not removed within a stage of compression for reciprocating and centrifugal units, these might be better choices.
- Sour and acid gas compression may require special materials of construction (NACE may apply, stainless steel and higher alloys may be needed). This can affect the relative cost, delivery time, and rental availability of different compressor types. Specialty compressors, such as acid gas compressors or compressors with high discharge pressure are generally hard to lease.
- None of these compressor types are amenable to use with a gas feed containing solid particulates or liquid mist. Premature mechanical wear, poor operation, and possibly equipment downtime or failure can result in any of these compressor types if the gas feed contains solids and/or liquids.
- Oil-flooded screw compressors are often applied, taking advantage of their relatively low capital cost, in well-defined applications where they are proven to work well. This includes external refrigeration and instrument air; they are also often applied as VRU's since these rather difficult operations often require substantial turndown flexibility and the compression ratio required is often within the capacity and pressure requirement of one screw compressor, avoiding multiple stage reciprocating machines.
- Centrifugal compressors are often selected for large applications in processing facilities expected to have a substantial on-line life. They represent a good long-term investment balancing higher capital costs against lower operating and maintenance costs. Higher capex associated with centrifugal units may not be an issue where one centrifugal unit can handle the entire gas stream versus multiple trains of reciprocating units. They are the lowest capital and operating cost options in applications with very large flow rates (For example, 50 MMscfd or more).
- Centrifugal compressors are a particularly good choice for mol sieve dehydration regeneration because they have a small footprint and can produce the pressure needed with in a single stage and are low maintenance with good availability as prove in service.
- Reciprocating machines are, for many upstream and midstream operators, the default device that is selected when there is not a reason to select one of the other technologies given their wide applicability, familiarity, and easy access to replacement parts and services.

Table 2. Summary of Characteristics of Three Compressor Types

	Some Common Applications	Capacity Constraints	Pressure Ratio Constraints	Maintenance / Reliability	Turndown / Operation Flexibility	Advantages	Disadvantages
Reciprocating	VRU, flash gas refrigeration, plant feed, pipeline, boosting, gathering systems	Highly flexible, may require multiple trains (commonly done).	3:1 max per stage, but multiple stages can go to very high pressure.	Higher maintenance required to maintain reliability.	Reasonable turndown and can retrofit machines for new conditions.	Common, widely adapted. Cover any pressure and flow range (multiple trains common). Reasonable turndown & can be modified for different conditions. Rental units commonly available.	Complex machines with higher maintenance. Large footprint. High pressure drop and a significant amount of ancillary equipment is required between stages.
Oil-Flooded Screw	VRU, flash gas, refrigeration	Small-medium volume applications are typical.	High pressure ratio: up to 20:1. Usually not applied to high outlet pressures.	Higher maintenance required to maintain reliability.	Very good turndown.	Lower capex, up to 20:1 comp ratio in one compressor. Small footprint. Very good turndown. Rental units available.	Low efficiency. Cross-contamination of oil and gas. Limited proven applications. Limited pressure range. Higher maintenance.
Centrifugal	Plant feed, pipeline, boosting, auto-refrigeration, mol sieve regeneration	Economics generally relegate these machines to larger applications.	Typically, 1.6 – 2.3 per stage, multiple stages can be used.	Lower maintenance and high reliability.	Limited turndown and flexibility.	Largest volume through one train. Best efficiency. Low maintenance.	High capex per unit. Long lead time. Lower flexibility and turndown. Difficult to repurpose or spare.