In recent years, unprecedented oil and gas production growth from major shale basins across North America has spurred an increase in the need for capacity and utilisation of natural gas processing facilities.

Many processing plants in operation today were originally designed to handle flows of 20 – 100 million standard ft³/d. However, as demand for both gas and natural gas liquids (NGLs) has risen, more facilities are being upgraded to take on higher volumes – some to the tune of 250 – 300 million standard ft³/d as shown in Figure 1.

The most popular approach from operators and EPCs conducting these expansion projects has been to replicate the existing technology in the gas plant. For residue compression, that means adding more high-speed reciprocating units historically driven by gas engines. These packages are often highly economical when incremental horsepower is required. However, when the plant capacity is being significantly increased, a business case can be made for installing one or more centrifugal compressors. Operating centrifugal and reciprocating compressor technologies in a mixed arrangement is not uncommon and can provide wide-ranging benefits to the operator, including increased reliability, lower maintenance, and reduced CAPEX, while maintaining, and in some cases increasing, the flexibility within the facility.

Utilising the two compressor technologies in series or parallel, however, does bring up a number of important questions, one of which is: how can reciprocating and centrifugal units be operated together to deliver the most value to the end-user?

This article explains the items that facility operators, EPC contractors, and original equipment manufacturers (OEMs) must consider to ensure proper operation when combining different compressor technologies within a residue service.

Travis Phoenix, Siemens Oil & Gas, USA, sets out the considerations for implementing mixed compression arrangements in gas processing facilities.
Reciprocating vs centrifugal compressors

When upgrading and/or expanding an existing natural gas processing facility, the compressor technology that delivers the most value over the life of the plant is highly dependent upon site-specific variables and operator objectives. While reciprocating units have historically served as an economical option, centrifugal units are becoming increasingly attractive as flow capacities increase.

While most of the centrifugal units installed today are going into greenfield facilities, there is a compelling case for their implementation in existing facilities undergoing expansions; primarily due to the fact that brownfield installations often have enough production from existing wells to immediately run the plant at 100% rated capacity. For a new-build, it is likely that the plant will be run at lower capacities until production from the field is ramped up.

Despite the potential benefits, many operators and EPCs do not always consider the mixed use of reciprocating and centrifugal compressors either in series or in parallel. Much of this is attributable to the belief that combining the two technologies, either in series or in parallel, can introduce unnecessary project complexity and costs. Generally speaking, however, this is not an accurate assumption. In fact, there are many different types of oil and gas facilities, including compressor booster stations, where the two technologies operate in a combination arrangement to maximise flexibility and minimise operating costs.

Ultimately, failure to evaluate combined configurations for gas plants limits available options for the end-user, which may inevitably result in higher costs over the life of the facility.

Operating centrifugal and reciprocating compressors in combination arrangements

The final required process conditions of the facility must be considered when determining the compressor designs and arrangement. If a significant increase in capacity is desired, such with expanding gas processing facilities, centrifugal and reciprocating compressors in parallel is a good option. If there is a reduction in suction pressure while maintaining or even increasing the discharge pressure, typically seen with depleting reservoirs or upgrades to booster stations, installing the two types of compressors in series is the typical configuration.

When evaluating the implementation of a mixed compressor arrangement on the same header in a gas plant, a pulsation study must be completed.

This is especially the case when the plan is to install one or more centrifugal compressors downstream of reciprocating units (i.e., in series). In such cases, the lower pressure streams from the recips combine to form one larger-volume, medium-pressure stream, which is then compressed to an even higher pressure by the centrifugal unit. These plant arrangements can sometimes lead to comparatively stronger pulsations than when they are operated in a parallel arrangement. The pulsation behaviour of not only the piping system, but each compressor must be evaluated.

A pulsation study enables operators to design a system in which pulsation levels at the centrifugal units are less than line pressure, typically between 0.5 – 2% lower. An interaction study for reciprocating compressor pulsation effects may also be conducted to determine how low pulsation levels must be to prevent surge. Appropriate pulsation control methods, such as pulsation bottles (shown in Figure 2), isolated volumes, and piping and valve configurations, can then be implemented at the

![Figure 1. Natural gas processing plant.](image1)

![Figure 2. A reciprocating compressor.](image2)

![Figure 3. Siemens Dresser-Rand DATUM centrifugal compressor.](image3)
Advantages of combination compressor arrangements

In either a brownfield or greenfield application, the use of combined reciprocating and centrifugal compressor packages is virtually identical up to around 100 million standard ft³/d. But when the plant increase is larger than this, the CAPEX of a centrifugal compressor driven by an electric motor can be as much as 40% lower than that of the reciprocating compressor solution driven by a gas engine.

These savings are largely attributable to the power density of the centrifugal solution. Take, for example, an increase in 200 million standard ft³/d. For a plant this size, the increase in the entire inlet and residue gas compression duty can be handled by just one or two centrifugal compressors. Typically, 7 – 10 reciprocating units would be required to handle that same duty.

Additionally, fewer installed units means less plot space and reduced need for foundations, piping, wiring, and electrical systems. There is also no risk of carrying over any lubricant oil into the compressed gas with centrifugal units, thus eliminating the need for an oil removal mechanism.

Increased availability and flexibility

Industry-accepted levels of availability for centrifugal compressors are -99.7%. Reciprocating units, on the other hand, are around 97.3%. Siemens, for example, recently installed a series of gas plants with a total capacity of 1000 million standard ft³/d. Since becoming operational, the plants have exhibited 99.9% availability, which is the highest level the operator has achieved at any of its existing facilities.

Combining reciprocating and centrifugal compressors in parallel also offers better flexibility over the use of just one technology. For example, when increasing an existing 100 million standard ft³/d gas plant to 200 million standard ft³/d, the operator can design the centrifugal unit to handle the total capacity of 200 million standard ft³/d, only 50% of the capacity, or any other combination (Figure 3). The combined turndown and overload capacity of this configuration then allows the operator to take the reciprocating units on- and off-line during production fluctuations.

Reduced maintenance requirements

Maintenance requirements for centrifugal machines are lower than reciprocating units due to reduced wear and tear on internal components, which allows for extended maintenance intervals. In many applications, centrifugal compressors run uninterrupted for five to seven years between inspections. This is largely why facilities that require 100% uptime, such as petrochemical plants and offshore platforms, utilise centrifugal units, often without any installed spares.

When operating in the same service, the maintenance costs (parts and service) for a centrifugal solution are approximately 10 – 15% of that of a reciprocating solution.

Operating envelope

As previously mentioned, facility expansions will typically operate at full capacity once brought online. The need for high turndown capability while maximising efficiency is still required. High turndown is one of the primary advantages of reciprocating compressors. While centrifugal units possess less flexibility, they are still capable of reliably achieving 30% turndown without the need for recycling. This turndown ability, combined with the reciprocating compressors, allows the operators the ability to operate efficiently at any capacity. In certain applications with variable discharge pressure requirements, centrifugal compressors may provide greater flexibility because surplus power can be used to increase the compressed flow.

Making the right decision

The decision of what compressor type to specify for a gas plant upgrade will ultimately be driven by project-specific factors, including location, pressure ratio, flow rate, emissions, CAPEX, OPEX, delivery time, maintenance, downtime, etc. Replication of existing designs, typically with the addition of more high-speed reciprocating units, has been the common approach for operators and EPCs. However, in cases where two or more reciprocating units are being added, the use of centrifugal technology, at the very least, should be evaluated. Duplication of existing equipment is viewed as the easiest approach but does not always yield the most value to the operator.

As outlined, the implementation of mixed compressor arrangements does require certain steps to mitigate potential issues, such as pulsation. However, these considerations are comparatively small to the cost of the overall project expansion and are typically recouped relatively quickly (if not immediately) as a result of lower CAPEX, reduced maintenance requirements, and higher plant availability. The latter alone could tip the scale in favour of implementing a mixed compressor arrangement – particularly if contractual production guarantees are in place.