Decarbonization objectives can be achieved through various techniques.

By Gautam Chhibber and Sanda Baciu.

Methods for reducing fugitive emissions from natural gas compression stations

Oil and gas companies across the supply chain are under intense pressure to reduce greenhouse gas (GHG) emissions, most notably methane. In the midstream sector, natural gas compressor stations represent a significant source of methane emissions. Historically, regulations applying to these facilities have focused on emissions generated as a result of normal combustion processes, such as burning fuel in gas turbines or gas engines and blowdown and venting during maintenance activities.

Fugitive emissions from centrifugal compressors, comparatively, have broadly been accepted as a normal part of pipeline operation. However, this sentiment is changing as pipeline companies look to voluntarily reduce their carbon footprint and ensure compliance with future regulations. This is particularly the case in Canada, where new compressor methane limits will come into effect in 2023. Other countries are also working toward implementing similar policies.

Regulatory requirements are being updated at state and local levels as well, prompting pipeline operators to pursue technological advancements that will reduce their carbon footprint.

Fortunately, numerous commercial technologies are available that can help midstream companies reduce or capture fugitive emissions from centrifugal compressors.

Understanding fugitive emissions

In centrifugal compressors, seals installed around the rotating shaft are used to prevent process gas (i.e., methane) from escaping where the shaft exits the compressor casing. Wet seals, which use circulating oil as a barrier, were used extensively from the 1960s to the 1990s. However, most compressors in operation today feature dry gas seals (DGS), which operate mechanically under an opposing force created by hydrodynamic grooves and static pressure [1].

DGS systems are available in multiple configurations. The most widely used for natural gas applications is a "tandem" design, in which two face seals (primary and secondary) are installed at the compressor end caps. During compressor operation, the primary seal absorbs the pressure differential. The secondary seal serves as a backup in the event of primary seal failure.

Though DGS systems are highly effective, small volumes of methane leak across the primary seal and vent to the atmosphere. The rate of leakage depends on several variables, including the size of the seal and operating pressure. Typically, primary leakage can be as high as 4 cfm (0.11 m³/min). However, Siemens Energy has developed DGS systems that can achieve 2 cfm (0.06 m³/min) or better of leakage.

Recompression with a recip

Recompression via an electric motor-driven reciprocating compressor provides the capability to recover and capture methane leakage across seals for injection back into the process gas stream. This typically occurs at the station suction or discharge header.

Depending on the design of the station, the recovered gas could also potentially be injected into the fuel inlet for the gas turbine.
or an onsite electrical generator. Using it as heating fuel is another potential application. The volume and flow rate of the process gas will ultimately dictate the size of the reciprocating compressor unit needed for the recompression system.

One significant benefit of recompression is that it allows for the capturing of blowdown emissions as a result of station depressurization during scheduled maintenance activities and planned shutdowns. When compressors are shut down for maintenance, process gas (often to the tune of thousands of standard cubic feet) in between isolation valves must be vented to the atmosphere or flared. Depending on how the station is operated, this could occur multiple times per year.

Another benefit of recompression is scalability. One recompression system can be used for multiple centrifugal compressors operating in the same service. Not only can it be used for compressors, but fugitive emissions from valves and other site hardware can be captured. In such cases, the sources are routed to a common header.

Reinjection into gas turbine inlet
A lower-cost alternative to recompression that allows for the burning of fugitive emissions in the gas turbine is to route the DGS primary and secondary seal vents into the turbine’s inlet. The resulting mixture of methane and air is exceptionally lean (typically around 0.007% based on a gas turbine inlet flow of 17.6 lbs/sec. [80 kg/sec.]), which is well below flammability limits.

This option may be a cost-effective solution in the future as little to no maintenance is expected, however, certain design aspects must be addressed. For instance, sufficient mixing of vented emissions with intake air is needed to ensure that flammability limits are not exceeded. This is the case when the compressor is in operation and when it is shutdown.

One primary drawback of this option is that it does not allow for capturing methane emissions during blowdown or settle out.

Enclosed combustion units
Vapor combustion units collect and burn fugitive methane emissions within an enclosed stack. However, unlike conventional flare stacks, combustion takes place at the bottom of the unit, where it is not visible.

Enclosed burners are natural draft and do not require a mechanical device to move fugitive emissions into the stack inlet. Instead, the heat generated from combustion naturally draws air in. Stacks are typically designed for high temperatures so that a large portion of the gas that escapes the flame combusts as it rises in the stack.

In general, enclosed burner systems are not well suited for higher pressure applications. The enclosed design means that too much gas will create a very intense flame, potentially damaging the stack insulation. Although the diameter of the stack can be increased to address this problem, there is a negative effect on turndown capabilities. Enclosed burners also typically require the installation of additional emissions monitoring equipment, which can increase cost and system complexity.

Flameless thermal oxidizer
With flameless thermal oxidizers, methane emissions, ambient air and auxiliary fuel are premixed and then passed through a preheated, inert ceramic media bed. Heat is transferred from the media to the gaseous mixture. The temperature eventually becomes high enough to oxidize the methane into byproducts like carbon dioxide and water.

Thermal oxidizer systems can be designed to handle emissions generated as a result of compressor blowdown or settle out. Additionally, the media bed is highly stable and resistant to temperature fluctuations, which means that the operating temperature can be precisely controlled. Lower temperatures coupled with uniformity of the media results in low levels of NOx emissions – often as little as 1 part per million by volume (ppmv). Overall removal efficiencies can be as high as 99.9%.

As is the case with enclosed burners, thermal oxidizers often necessitate the installation of additional emissions monitoring equipment at the compressor station. They also require an electric heater or gas burner to heat the ceramic media.

Double opposed gas seal
Unlike the previously discussed methods, which focus on capturing and recovering fugitive methane emissions for reinjection or combustion, double opposed gas seals work to virtually eliminate leakage of the methane from the compressor altogether.

In double seal configurations, two seals (primary and secondary) are installed in a back-to-back arrangement. An inert gas – typically nitrogen – is then supplied in between the two seals. Any leakage across the primary seal and into the vent comprises nearly 100% nitrogen, with only trace amounts of methane.

The primary drawback of this option is that a reliable seal gas supply of nitrogen is needed. Additionally, double opposed gas seals do not address methane emissions from compressor blowdown.

Ejector, supersonic ejector systems
An ejector is a device used to “suck” fugitive emissions vented to the atmosphere from the primary dry gas seal. It works similarly to a compressor or vacuum pump, however, it has no moving parts and thus requires little-to-no maintenance.

With ejectors, the motive fluid’s pressure
energy converts to velocity energy via adiabatic expansion in a converging nozzle. This results in the creation of a low-pressure area, which provides enough force to capture the fugitive emissions. The methane-air mixture then flows through a diffuser, where the velocity decreases and pressure increases, effectively recompressing the gas.

As is the case with traditional recompression systems, the gas can be reinjected into any number of operational processes, including the compressor inlet, fuel system inlet or heater inlet.

Ejectors cannot be used to capture methane emissions from blowdown or settle out. Another key drawback is that one ejector system is required per compressor, which can increase costs.

**Measuring fugitive emissions**
Decarbonization is a key objective for many organizations that use advanced instrumentation and infrared cameras to measure and report on fugitive emissions. Another solution involves using a Predictive Emissions Monitoring System (PEMS). Historically, PEMS have been associated with gas turbine emissions, but it can also be used to calculate gas seal leaks verified in the factory and correlated to site conditions.

Emissions for various scenarios like normal operation, pressurized and non-pressurized standby modes can be predicted based on speed, suction conditions and separation gas supply pressure while leveraging correction curves. PEMS can be incorporated within a turbomachinery control system to capture data and generate reports, eliminating the need for a separate system.

**Conclusion**
Reducing fugitive emissions continues to be a key area of focus for operators across the oil and gas industry. While in past years, regulations have primarily targeted emissions generated from combustion processes and blowdown activities, fugitive emissions from compressor stations are becoming more and more of a concern.

As outlined in this article, many available technologies can be leveraged to address methane emissions at compressor stations. Which specific technology to employ will ultimately be dictated by the design of the compressor station and other site-specific variables. In all cases, technical evaluation is required to ensure that the solution aligns with operator objectives for scalability, maintainability, capital expenditure and reliability.

---

**Compressor technology with a digital advantage**

Howden offers unparalleled expertise in every application where reliable, round the clock operation is paramount.

With Howden’s digital solution Uptime and our in-depth knowledge of compressor technology, we can increase compressor reliability, predict maintenance requirements and optimize performance on demand.

For more information contact:
7204 Harms Road, Houston, TX 77041, USA
t: 1-800-55-ROOTS (76687) e: inquiries.USA@howden.com

---

CT2