STRATEGIES FOR MAINTAINING COMPRESSOR RUNTIME IN COLD WEATHER

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ABSTRACT

Gas lift is long known to be an effective and versatile form of artificial lift and is widely used in oil and gas production. The gas lift process is dependent on gas pressures not naturally available from oil and gas production facilities. Rather gas must be pressurized through use of a compressor and thus compressors are a vital component to the gas lift process. Unfortunately, some production operators have experienced unsatisfactory levels of compressor runtime, particularly during periods of cold weather. When the compressor is down, well production suffers. Thus, some operators have turned away from gas lift as a viable artificial lift method over concerns of compressor reliability. This is unfortunate and demands education on compressor design and operation strategies to increase compressor runtime, especially during periods of cold weather. This paper addresses the key factors that impact compressor runtime during periods of cold weather and offers insight as to how to increase the reliability of gas lift system.

INTRODUCTION

The advent of unconventional production has demanded that operators rethink their artificial lift methods. Conditions present in unconventional production such as high gas/oil ratios (GORs), solids laden fluid production and deviated wellbores creates challenges for the longstanding artificial lift methods such as beam pumps and Electric Submersible Pumps (ESPs) (Pronk et al. 2019; Richter, et al. 2016). Gas lift is a versatile and robust artificial lift method that is now a preferred artificial lift method with many operators in their Permian Basin unconventional resources (Richter, et al. 2016).

Gas lift is dependent upon pressures not naturally found in most production environments however. Thus, a gas compressor must be employed to increase the pressure of gas to be used in the gas lift process. As mentioned above, the gas lift process brings multiple advantages to the table, fundamentally its simple downhole design, which reduces complications that are often time intensive and costly to fix. However, gas lift is not without its vulnerabilities. The gas compressor, a key component to the gas lift process, if not understood well can create complications and downtime. Gas compressors are not new and a whole industry exists to provide oil and gas producers with rental compressors to serve their gas lift needs (Elmer et al. 2017). Yet one particular aspect of gas compressor operation seems confuse, frustrate and repeatedly inflict downtime upon compressor operators and mechanics alike: cold weather operation.

Understanding how to properly design, fabricate and operate compressors for use in periods of cold weather is imperative to maintaining acceptable runtimes. Compressors are often considered but a necessary evil by oil and gas production companies and their design and operation often overlooked and even balked at. However, compressor runtime directly correlates to oil and gas production, which is of prime concern to the production company. Thus, compressor reliability and runtime must not be overlooked in order for gas lift to be a viable artificial lift method for production operators.

DEFINITIONS

"Cold weather" is very much a relative term and warrants definition to be of greatest help to readers. For the sake of this paper's subject matter, cold weather will be defined as any ambient temperature below approximately 40°F. This is not intended to be a hard and fast rule, but rather an approximate number that considers compression equipment typically specified and operated in the Permian Basin region of the United States. To be clear, compression equipment can certainly be specified, designed and built to operate suitably at temperatures considerably below 40°F without retrofit or special operating procedures, but this is not the norm for equipment specified and sourced for the Permian Basin. For reference, the typical "West Texas Package", the title that is commonly bestowed upon compression equipment utilized in the Permian Basin, is typically characterized by lack of an enclosure (exposed to ambient conditions), nor is it fitted with heaters to add outside heat to the process.

THE CHALLENGES OF COLD WEATHER

In order to understand how to keep equipment running in cold weather, operators first need to understand the underlying issues that cause compressor shutdowns and/or prevent restart. Two issues surface as the most common culprits: first, problems created by the formation of hydrates in the process gas system. The term hydrate may be new to some readers and will be discussed more thoroughly in a subsequent section. Hydrate formation most often afflicts compressors when they are running, causing shutdowns. Since gas lift compression equipment is generally operated continuously (24/7/365), hydrate formation is generally the initiator and most common cause of downtime in cold weather. Other factors certainly contribute to downtime, but tend to be secondary issues. Thus, preventing hydrate formation will be of prime importance in maintaining runtime in cold weather.

Secondly, changes to lubricating oil viscosity in the engine and compressor crankcases can contribute to downtime in cold weather. Lube oil viscosity changes more commonly afflicts compressors when they are shutdown, making restarting difficult. But, if a compressor can be kept free of shutdowns from other issues and lube oil temperatures (and in turn lube oil viscosity) can be maintained, downtime is rarely incurred because of this issue.

HYDRATES

In wintertime oil and gas production environments, the words "ice plugs" and "freeze ups" are often tossed around. Yet the technicalities of what these terms really are is generally poorly understood. The subject is almost never discussed in field training classes. Engineering thermodynamic courses do not typically broach the subject. Taken at face value and with no further education, one would assume that that frozen water is at play. Yet, oddly enough, the so called “ice plug” or “freeze up” commonly occurs above the freezing point of water (32°F). This leaves one to question what is going on and whether an “ice plug” is indeed frozen water.

In the early 19th century English chemist Sir Davy Humphrey, while working with chlorine, discovered an “ice-like solid formed at temperatures greater than the freezing point of water and that the solid was composed of more than just water” (Carrol, 2020). When the ice-like substance melted, chlorine gas was released. In other words, this ice-like substance, known as a hydrate, is a combination of a hydrate former (generally a gas) and water, and forms when the mixture is under pressure. Natural gas commonly present in oil and gas production environments is also a hydrate former. All the necessary elements of hydrate formation are commonly present inside of compressors used in the gas lift process: water, natural gas, elevated pressures, reduced temperatures. Anyone familiar with compressor operations will confirm that theory aligns with reality when it comes to hydrates, namely that hydrates are a real factor to contend with in cold weather.

Though the term “ice plug” is not technically correct, it is instructive in the problems that hydrates create in compressors and piping systems in general. Hydrates form restrictions in flow paths and even block flow altogether as shown in Figure 1.

Figure 1 – Hydrate blockage in a pipe

Blockages to flow are perhaps the most common problem that hydrates create in compressors and gas lift operations. Partial blockages increase pressure drops in systems. A very common outcome of hydrate formation is a partial blockage in the main process flow path which restricts flow and causes an overpressure event and in turn a shutdown. Alternatively, a blockage in an instrument sensing line can cause an inaccurate pressure reading of a process variable. Playing that out, an inaccurate process reading can put equipment health at risk because equipment is allowed to operate in unintended conditions. In turn this can lead to severe equipment failure, causing extended downtime. It should be clear that partial blockages, even as insignificant as they might seem, can be the source of downtime and even equipment failure. Following this, little discussion ought to be warranted on the subject of complete blockages to flow paths. The outcome is often essentially the same, just with reduced time to shutdown and/or increased downtime to return equipment to running condition.

While rare, it should not be overlooked that there are also stories of near misses when ice plugs have become projectiles while trying to clear them out of pipes. Differential pressure across a hydrate plug inside a piping system that is beginning to thaw can dislodge and create a projectile that damages components when it moves, often very rapidly. In extreme cases dislodged hydrate plugs have been known to catastrophically damage piping systems, causing lack of containment of gas or even the hydrate plug itself.

It should be clear that hydrates are the cause of considerable trouble in oil and gas production operations and more particularly compressors. The subject is worth understanding better in order to mitigate lost production and even prevent injury. A number of strategies exist to deal with hydrates. As with many other things in life, prevention is the best policy and is the primary focus of this paper.

MITIGATING HYDRATE FORMATION

In theory, preventing hydrate formation in compressors is fairly simple. The first part of that process is understanding the conditions when hydrates can exist. As mentioned earlier, hydrates can form when water and a hydrate former (natural gas in this case) are present where elevated pressures and reduced temperatures exist. Defining the conditions where hydrates can exist is perhaps most easily done by looking at a chart known as a hydrate locus (reference Figure 2). The curves, or the diagonal lines in the center of the graph represent different gas specific gravities and delineate between regions where hydrates can form and where hydrates do not tend to form. Note that the area of lower pressures and higher temperatures is in the lower right region of the chart labeled "Region of no hydrates". Thus, if process pressures and temperatures are kept to the lower right side of the appropriate hydrate formation line, hydrates cannot exist. Admittedly, this chart is a simplistic method to gauge where hydrates do and do not exist. There are more complex and accurate methods to calculate the pressures, temperatures and gas compositions where hydrates exit. Those are discussed in other texts that deal more thoroughly with hydrates, such as Natural Gas Hydrates: A Guide For Engineers (Carrol, 2020). Or, if doing this work is a daunting task, many companies can perform this service. Regardless of the method chosen, the task at hand is determining if the process is operating in a pressure/temperature area where hydrates can exist. If so, determination must be made of whether the process can be modified to stay out of the region.

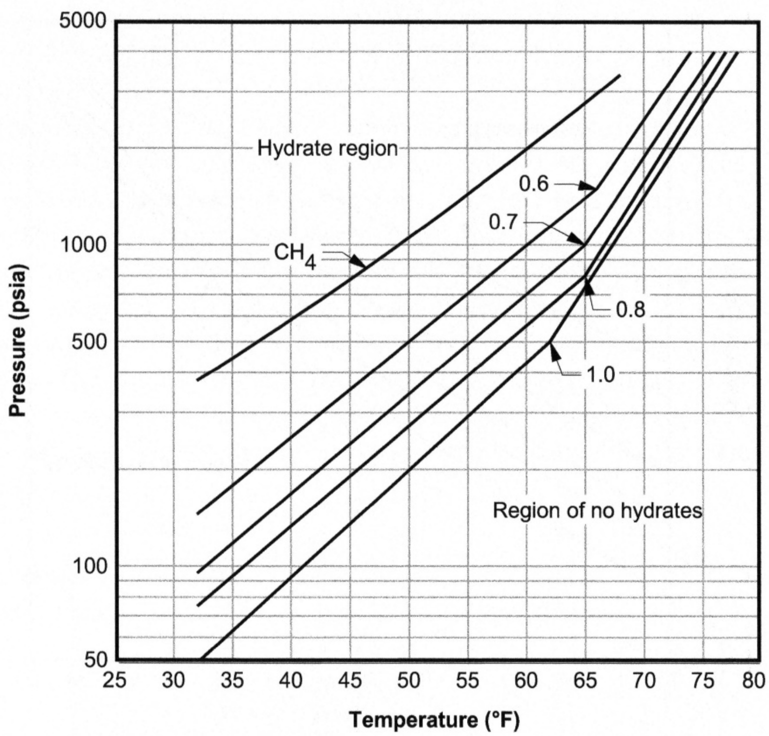

Figure 2 – Hydrate Locus for Natural Gas

Fortunately, compressors used in the gas lift application can pretty readily be adjusted such that process temperatures can kept out of hydrate forming conditions. Note that only temperature is mentioned in the last sentence. Previously, discussion is made of both temperature and pressure. Pressure is left out as a variable to be adjusted as it is rarely able to be adjusted much in the compression process. Temperature on the other hand is readily adjusted in the compression process given the right hardware on the compressor package. The next task is understanding what that right hardware is and how to implement it such that the appropriate temperatures are maintained.

SWINGING PROCESS TEMPERATURES

Compressing gases not only increases the pressure of the gas, but also increases the temperature of the gas. For the sake of preventing hydrate formation this is convenient. However, temperature limits exist within the gas compressor package and the system that receives the gas post compression. Thus, when gas is compressed in multiple stages, as is typical in gas lift applications, the gas must be cooled after each stage of compression to avoid exceeding temperature limits. These coolers use ambient air to cool the gas, so the amount of cooling changes as ambient temperatures changes. It is not hard to see then that as ambient temperatures change, so do the process gas temperatures at the outlet of each stage of cooling. During the warmer summertime and daytime temperatures, discharged gas is warmer; during the cooler wintertime and nighttime temperatures, discharged gas is cooler. Temperature swings of the discharged gas must be kept above hydrate formation temperatures and below material temperature limits of components in the gas lift compressor and system.

CONTROLLING PROCESS TEMPERATURES WITH LOUVERS

Skipping a lot of technical discussion on compressor package and cooling system design, control of process temperatures is done via altering the flowrate of ambient air through the gas cooling sections. This is generally done in one of two ways. First and most commonly, louvers are placed over one side of the gas cooling section. When fully open, the louvers allow airflow through the cooling section, creating maximum cooling. When fully closed, louvers restrict airflow through the cooling section, reducing cooling. Lovers can be partially open/closed and cooling can be regulated to some degree. When louvers are fully closed, airflow through the gas section is largely stopped, but airflow across the face of the gas section is still present, thus cooling doesn't cease entirely. Occasionally, louvers are placed on both sides of the gas cooling section and that arrangement can be rather effective in minimizing cooling to the lowest possible amount.

A second method of controlling process temperatures by way of cooler airflow changes is to alter the speed of the fan inducing the airflow. This is only really practical on electric motor driven fans. When using electric motors, a Variable Speed Drive (VSD) can be incorporated that alters the speed of the fan, and in turn and airflow and ultimately the process temperature. Louvers are generally installed even on electric motor driven fans (reference Figure 3) and when a proper control strategy is used can be very effective in controlling process temperatures.

Figure 3 – Electric motor drive gas cooler with automatic louvers

The presence of a louvers and/or a variable speed fan in and of themselves does not eliminate the formation of hydrates. Rather, it is only in the proper control of these devices that freedom from hydrates is found. Recall that swinging ambient temperatures create swinging process temperatures. Thus, altering the amount of process gas cooling is sometimes necessary. In springtime and fall-time when large ambient temperature swings occur throughout the day, the necessary frequency of changing the amount of cooling is twice a day. Practically an operator would have to change the louver position or the fan speed once in the morning and once in the evening. This is often impractical or simply does not happen. Consequently, process gas temperature limits are either exceeded or allowed to dip into hydrate formation ranges and a compressor shutdown occurs. Manually controlling louvers is generally not a successful proposition. Rather, automatic control of these devices is a more successful approach, decreasing shutdowns and increasing runtime. As an added bonus, operator labor is often reduced as well. Reference Figure 3 and note the pneumatic louver actuator (top right) that is set to automatically control louver position and in turn process gas temperatures.

Selecting a setpoint for process temperatures to be controlled to is the final step in the process. In gas lift compression applications, there is rarely need for real tight control of the process temperatures. The fundamental requirement is that process temperatures be kept above the hydrate formation temperatures and below material temperature limits. Practically, this generally means keeping temperatures between about 75°F and 125°F. Certainly, deviations from this general rule exist and each case warrants at least a quick review. One matter to be aware of is that heat is continuously being lost from process gas to the surrounding environment. Thus, if process gas temperatures are barely above the hydrate formation temperature right out of the cooler, it is likely that they will dip below the hydrate formation temperature as gas travels through the piping system and heat is lost to the environment. Therefore, there is value in maintaining a margin of temperature above the hydrate formation temperature to account for downstream heat losses. Alternatively, piping systems can be insulated to help maintain temperatures.

PRESERVING PROCESS HEAT WITH INSULATION

In environments where ambient temperatures are particularly low or winds are high, process gas heat lost to the atmosphere through piping systems can be significant. Elevating process gas temperatures out of the cooler may not be enough to overcome heat lost through piping systems, allowing gas to dip below hydrate formation temperatures. Insulating piping systems is a cost effective, long lasting and low maintenance way to help preserve heat in piping systems. Components with large surface areas transfer large amounts of heat away from of process system, thus are of prime concern when insulating. Separators (called "scrubbers" on gas compressor packages), for example, with their large surface areas, are the source of a large percentage of the on-skid hydrate problems and can really benefit from insulation (reference Figure 4 for a nicely insulated scrubber).

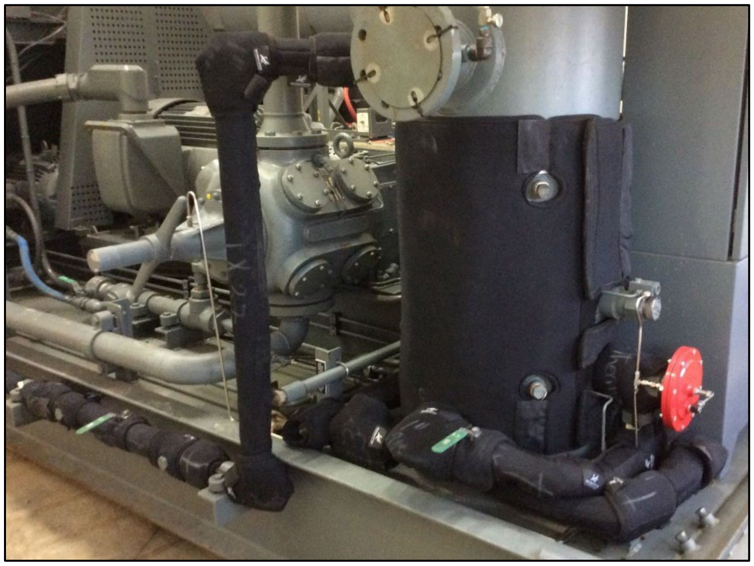

Figure 4 – Insulated scrubber and connected piping

ADDING HEAT TO PROCESS SYSTEMS

Sometimes controlling process gas temperatures via louvers and preserving heat with insulation is still not enough to keep temperatures above the hydrate formation temperature. In these situations, adding heat to the process system from external sources can be productive in reducing problems with hydrates. External heat can come from a number of sources, including Engine Jacket Water (EJW) from internal combustion engines, natural gas fired heaters or electric heat tracing. As most gas lift compressors are powered by internal combustion engines and must reject the heat of the combustion through an EJW system, that heat can be used to add heat to process gas. A particularly effective way to combat hydrate formation with EJW heat is to heat trace the liquid section of scrubbers. This can take on several forms, including circulating EJW in the scrubber skirt. This non-pressurized base of the scrubber contains EJW such that the bottom head of the pressure vessel portion of the scrubber is bathed in hot EJW, as shown in Figure 5. Doing so heats the separated liquids in the base of the scrubber such that when they are dumped and take a large Joule-Thompson induced temperature drop, they do not form hydrates. Sometimes heat is needed in places where bathing the component in EJW is not practical and in those cases circulating EJW through tubing that is wrapped around the component or run alongside the piping system can be productive. While the tubing method can be convenient, far less heat is transferred to the process gas and is less effective. Covering the heat tracing tubing and piping system with insulation is recommended.

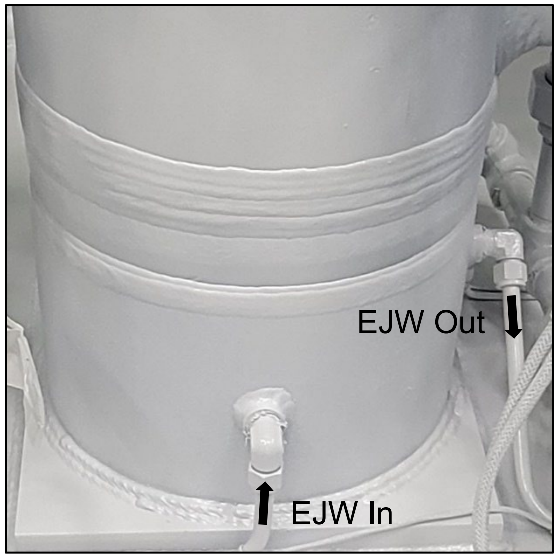

Figure 5 – EJW scrubber heat tracing

On electric motor driven compressor packages, EJW is not available and thus heat must come from another source. Natural gas fired catalytic heaters are another method of adding external heat to specific components within a process system, especially control valves. Catalytic heaters are commonly affixed into a removable enclosure that may installed on a control valve. Catalytic heaters are flameless, so no concern of an ignition source is warranted. The obvious advantage of natural gas fired heaters is that no electricity is required, which in some cases is not an option. When electricity is available, or for lengthy piping runs that call for heat, electric heat tracing can also be effective. Not unlike heat tracing with EJW tubing, electric heat tracing is most effective when covered with insulation to help maximize heat transferred into the piping or component.

<u>CHEMICAL HYDRATE INHIBITORS</u>

Emphasis has been on placed on modifying process temperatures to keep them above hydrate formation temperatures. On the compressor skid and with proper planning, this is an effective and cost-efficient strategy. In fact, Elmer concludes his paper stating “Maintaining elevated gas-cooler discharge temperatures…eliminates the need for methanol injection for hydrate prevention.” (Elmer et al. 2017) The author does not disagree, yet acknowledges that a couple of situations arise where alternative methods of hydrate prevention can prove to be useful. First, if cold weather occurs and none of the measures previously discussed have been implemented, a quickly deployable method of hydrate prevention might be needed. Secondly, off-skid, preserving heat in the process system can be difficult as the sources of heat, namely the heat of compression, are not present. Thus, maintaining temperatures above the hydrate formation temperature can be challenging or impossible.

Fortunately, chemical inhibitors exist that also prevent hydrate formation. Not unlike the use of salt on sidewalks, or antifreeze in engines, various substances can be injected into gas streams to act as an antifreeze agent, or more technically a freeze point depressant. A myriad of fluids exist that can be used, but the more common ones to consider are: methanol, ethylene glycol and triethylene glycol. When using a chemical inhibitor, the freeze point or hydrate formation temperature depends largely upon the concentration of the inhibitor in the process stream. In other words, the higher the flowrate of the process stream, the higher the injection rate of your chemical of choice. Similarly, the lower the desired freeze point, the higher the required concentration of chemical (and thus a higher injection rate). Oilfield chemical companies exist that specialize in chemical hydrate prevention and can make recommendations on both the chemical used and the injection rate.

Chemicals must be continuously injected to prevent hydrates. The expense of a chemical injection program can add up quickly making chemical injection as a hydrate prevention strategy less desirable than temperature management. However, chemical injection has its place and should not be ignored entirely when battling problems due to hydrate formation.

CHALLENGES WITH LUBE OIL VISCOSITY

In extreme cold weather (< 20°F) and if frequent or extended downtime is anticipated, the viscosity of crankcase lube oil may contribute to equipment downtime. As mentioned earlier, this factor is not usually the instigator of equipment shutdowns, but rather one that extends downtime by making equipment restart difficult. Compressor and engine crankcases require lube oil to be within a certain viscosity range to operate successfully and that viscosity is controlled in part by temperature. If equipment shuts down for extended periods and temperature in the crankcase dips and viscosity rises above manufacturer specified values, heat must be added to the crankcase to safely restart the equipment. While heat can be added manually by external heaters, this can be a laborious process and is not welcomed by equipment operators if frequently required. To address the issue, electric crankcase heaters may be added to the engine and compressor that are thermostatically controlled and turn on when oil temperatures drop below a specified value.

CONCLUSION

Understanding how to maintaining compressor runtime in cold weather is a necessary tool in tool bag of engineers, technicians and operators alike. The task is not difficult, but knowing the proper tools and how to use them is necessary. The most effective strategies and hardware have been discussed and can be summarized in this way:

1. Control process temperatures via use of automatic cooler louvers and/or a VSD
2. Preserve process heat through use of insulation, particularly on problematic components

3. Add heat to problematic process components by use of external heat sources like EJW, catalytic heater and/or electrical heat tracing
4. Inject methanol to the process stream, but only after implementing above-mentioned strategies
5. Install crankcase lube oil heaters if restarting compressors becomes a problem

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