RECOMMENDED PRACTICES IN HIGH PRESSURE GAS LIFT INSTALLATIONS

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ABSTRACT

High Pressure Gas Lift (HPGL) has established itself as a viable and valuable high-rate artificial lift method well suited to the challenges in modern unconventional production environments. Operators across all unconventional basins in North American are increasingly turning to HPGL to help them produce wells, especially during the initial production (IP) phase of the well's life. To help operators successfully and efficiently implement HPGL into their operations, learnings from the first seven years of HPGL installations is being compiled into the industry's first recommended practices for HPGL. The experiences and learnings from multiple operators using HPGL, along with the experience of HPGL experts is sought and shared.

INTRODUCTION

This paper is intended as a practical guide for production engineers, facilities engineers or anyone considering implementing and optimizing HPGL. What follows is a discussion of the issues that have been found to be important to the success of HPGL installation and operation. In depth treatment of the issues is not the intent, but rather a brief explanation of the core issue and perhaps a few related issues to consider. Where existing research or case histories offer insight on the various issues, those references are given for additional reading. It is hoped that this paper will aid HPGL practitioners in more effectively implementing and optimizing an increasingly popular form of gas lift.

NODAL ANALYSIS

The success of every project is impacted by advanced preparation and a HPGL project is no exception. Long before any equipment is ordered or set on location, planning should be occurring. Of utmost importance is conducting a nodal analysis. First, readers should be aware that nodal has been shown to closely match real-world observations in HPGL installations (Pronk et al., 2019). Next, readers should be aware that nodal does more than accurately predict fluid lift rates. Nodal analysis also serves as a helpful engineering tool in designing the entire gas lift system. For instance, downhole tubular selection and flowline selection are critical variables in determining production performance. Nodal enables development of a sensitivity analysis of these variables and their impact to well production. While discussing nodal, reminder should be made that gas lift performance is dependent on injection rates. Many operators simply use a nominal gas injection rate that perhaps they heard from a colleague or maybe was used previously. Variations between wells are often significant enough that using the same recipe leaves a lot to be desired in terms of well production. Too, optimal gas injection rates can change throughout the life of the well and should be evaluated and adjusted as necessary (Abdelkerim et al., 2024). To say that using nodal analysis to help guide the design of a HPGL installation is important would be an understatement.

GAS SUPPLY

As the name implies, gas lift utilizes gas and thus an adequate supply of gas is required to initialize and sustain a gas lift operation. How much gas is needed to perform the gas lift will be determined by the nodal analysis discussed previously. Most wells that are candidates for gas lift have a relatively high

Gas-Liquid Ratio (GLR) and give up some gas on their own. Occasionally, such as in a kick-off operations, the well does not produce enough gas to sustain the gas lift operation. In such cases an outside supply of gas is needed to bring the well on and start the natural flow of gas. This outside gas supply could be from other nearby wells that come into the production facility. Alternatively, sometimes a “buy back line” is needed, where gas is purchased from the local gas gathering company. In either case, ensuring adequate gas is available is essential for a successful HPGL operation.

FLOWLINE SIZE

Mentioned briefly earlier, but worthy of a more discussion is the selection of flowline size. An inverse relationship exists between fluid lift rates in gas lift and the back pressure that is put on the production side of gas lift systems. Thus, to maximize fluid lift rates in gas lifted wells, back pressure must be minimized. Operators accustomed to Electric Submersible Pump (ESP) installations in particular are often unaware of the negative production impact that undersized flowlines can have on HPGL installations. This is not untrue of gas lift installations in general. However, the problem is exaggerated in HPGL installations as the flowrates are considerably higher. In turn the pressure drops through those lines are correspondingly higher. Thus, pressure drops in flowlines must be carefully considered and managed to maximize HPGL performance (Pronk et al., 2019; Jordan, 2022).

FLUID TAKEAWAY CAPACITY

HPGL has been praised for and is desired by operators for helping achieve high IP rates. Thus, it is reasonable to think that accommodation has been made for the desired large production flowrates. However, unexplainably, multiple operators have cited bottlenecks in takeaway capacity from HPGL installations. Some operators have simply converted existing conventional gas lift facilities to HPGL facilities and have not made necessary changes to accommodate the corresponding large increase in fluid volumes. When implementing HPGL into an existing production facility, review of the entire facility should occur, including fluid takeaway capacities. Potential fluid volumes can be accurately predicted by nodal analysis, previously discussed.

PRODUCTION TREE PLUMBING

HPGL tends to be used early in the life of a well to help achieve that high initial production rates that many operators are seeking. Subsequently another form of artificial lift is employed that is more fitting for the next phase of production. Increasingly, operators are thinking about the subsequent artificial lift method and the longer-term artificial lift strategy for their wells. This is an important consideration as early planning and design can considerably ease and reduce the cost of transition to the next phase of artificial lift. For instance, increasing numbers of operators employing HPGL are now configuring their production trees for bi-directional flow (Fig. 1) through the use of valving. Valves allow for changing production flow direction without disassembly or modification of production trees, injection and/or flowline piping. As such, transition from annular flow HPGL to tubular flow HPGL is readily possible (McNeilly et al, 2024). In other instances, operators can transition to conventional gas lift (tubular flow). Either way, elimination of the need to shut in a well and perform work on the production tree and piping is almost always worth the added additional expense up-front.

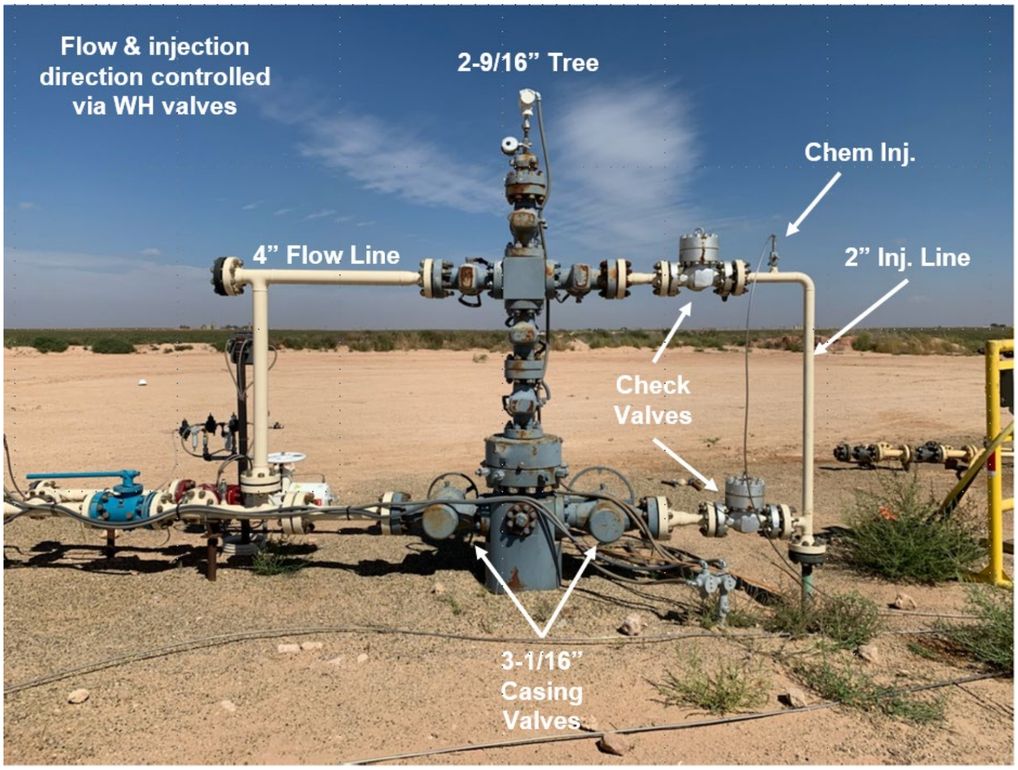

Figure 1 – Production tree configured for bi-directional flow

TUBING DEPTH

One of the primary benefits of HPGL is the ability to lift from end-of-tubing (EOT) from day one. Lifting from EOT lightens as much of the fluid column as possible and in turn achieves the lowest bottom hole pressure (BHP) possible. The deeper the tubing is inserted into well, the lower the BHP that can be achieved. Clearly, lifting from the deepest point reasonably possible is advantageous. Inserting the tubing into the heel of the well has become commonplace and is widely accepted. Practically, many operators are inserting EOT to inclinometer readings of 60°-70° (Pronk et al., 2019). Greater depths begin to require snubbing or special operations that seem to be deemed not worth the expense and/or effort for the added gain in depth of tubing.

CORROSION PROTECTION

Historically, oil and gas wells have been competed with a production packer, isolating the well's casing from production fluids and providing safety from corrosion. With HPGL production flow occurring up the annulus, isolation of the casing is no longer possible and protection from corrosion by another means is necessary. Admittedly, concern over casing corrosion has been one of the primary concerns by operators venturing into HPGL. Fortunately, excellent chemical corrosion inhibitors exist that have proved to be quite effective. In the eight years since its first implementation, the author is unaware of a single instance of a well casing corrosion problem in an HPGL installation. While a few chemical delivery strategies exist, atomization at surface is undeniably the simplest and has been shown effective. Injection of the liquid chemical corrosion inhibitor occurs downstream of the discharge of the compressor and before the production tree. It is worth bringing up here that many compressors used in HPGL installations do not have an aftercooler and thus the gas injection temperature can be upwards of 250°F. Suitability of the corrosion inhibitor should be confirmed at the elevated temperatures (McNeilly et al, 2024).

OFF-SKID COMPRESSOR PIPING CONNECITONS

Several topics should be addressed with regards to operator piping connections to the HPGL compressor. First, all HPGL compressors are of the reciprocating type and inherent to this design are pressure fluctuations in the process gas known as pulsation. Pulsation can couple with pipe at elbows and tees to induce a lateral vibration. Off-skid piping should be supported more substantially than merely holding it up. Rather, off-skid piping connected to compressors often needs relatively substantial bracing that imparts stiffness and resist vibration. This can be a complex matter and periodically calls for an off-skid piping vibration analysis.

Secondly, recognizing that HPGL can be a relatively short-lived form of artificial lift, an off-skid bypass around the HPGL compressor is recommended. In other words, the inlet side of the compressor is connected to the discharge side with a block valve located in between (Jordan et al, 2022). When the compressor is decommissioned and demobilized, gas supply from the upstream feed compressor or the gas lift system is not stranded and can readily continue to flow to the well. The bypass loop should be constructed in such a way that removal of the compressor is not impeded and that reinstallation in the future is possible. Periodically HPGL is employed later in the well's life for kick-off following workover or to unload water from frac hits.

Third, all compressors have on-skid separators ("scrubbers") that separate fluids from the process gas and must be drained. The scrubber dump line, as it is known, must be connected to a lower pressure system where fluids can be injected. The production flowline is a suitable and common location to connect this dump line to. Some operators like the protection afforded by connecting the dump line downstream of the production choke, but upstream of the Emergency Shut Down (ESD) valve. Regardless of where exactly the dump line ties into the flowline, the flowline should be adequately protected from overpressure events by a properly sized pressure relief valve.

COMPRESSOR FLEET MANAGEMENT

Many operators that have embarked on trying HPGL find themselves liking it and subsequently starting a broader HPGL program for many wells. Ensuring a timely supply of HPGL compressors is imperative to a successful HPGL program. Many operators end up leasing a fleet of compressors to serve their needs. Differing from compressors used in conventional gas lift or other applications, HPGL compressors tend to be moved around much more frequently. Like other compressors, HPGL compressors are typically leased on yearlong (or longer) contracts. Rotating leased compressors off wells that no longer need them to new wells or to wells requiring kick-off tends to be a more frequent occurrence. As such, management of the fleet of compressors tends to be overlooked and can become a challenge if not understood early on and planned for. While compressor leasing companies will likely help in the effort, no organization is better positioned to manage the effort than the operator given the intimate knowledge of wells' stage of life and artificial lift needs.

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