GAS LIFT IN A BEAM WORLD: GETTING YOUR WELLS, FACILITIES, AND PERSONNEL IN ORDER

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ABSTRACT

This paper will discuss well applicability for gas lift installations, including identifying the best candidates for lift conversion, and benefits of converting in a capital constrained environment. The topics of GOR, deviated wells, solids handling, and typical production rates will be discussed, as well as comparing gas lift to other popular lift types' efficiency and range.

While particular wells may be good candidates based on the aforementioned criteria, surface considerations also play a pivotal role in gas lift installations. The impact of electric infrastructure vs. gas powered compressors is an important topic, as operators today seek to minimize grid impact of artificial lift. Field-wide opportunity costs of gas & electric supply, fluid processing considerations at central tank batteries (CTBs), and permitting will also be discussed. Finally, this paper will cover operating considerations and installed equipment to enable successful operations (metering, control, protection, all-weather reliability, automation/surveillance, safety).

Operating practices, maintenance, training, and personnel costs are discussed in the final section, as gas lift is only successful with qualified operations personnel. A comparison of gas lift operations to other lift types will be made, and will feature the differences in surveillance.

INTRO

As production in the Permian Basin has seen a dramatic increase over the last 3-5 years, so has the use of gas lift as a method of artificial lift. Gas lift is a preferred method of artificial lift to deal with the type of production that is associated with the Wolfberry, Wolfbone, Bone Springs, and other unconventional reservoirs with high Gas Oil Ratios (GOR). The widespread use of gas lift is causing a paradigm shift when considering artificial lift in the Permian Basin.

Well Characteristics

Due to the recent exploration of shale formations that contain 40+ API oils, the candidate selection for gas lift wells has increased dramatically. This is mostly due to the higher GOR's (1500+ SCF/STB), that are typical to the lighter crudes. Most artificial lift resources claim that beams and ESPs are fair at handling gas with a basic bottom hole assembly (see Table 1), but it has been proven time and time again that they are actually very poor at handling gas. Beams and ESPs with a more robust gas handling system, such as charge pumps, gas separators and variable slippage pumps can be considered fair at handling gas. In reality, wells are not steady state, and these lift systems are no match for some of the extreme gas volumes (2500+ SCF/STB) that are seen on depleted solution gas drive reservoirs. These large gas volumes will cause ESPs to gas lock regularly. While beams will experience gas locking as well, it is gas compression that can be the most dangerous. This is due to the violent rod dynamics after the plunger breaks out past the gas bubble, and is a reason for failing parts. The problems presented to these mentioned pumping systems by gas not only delay production, but can make the cost of workovers extremely expensive per year. This expense was the primary driver to identify a different lift type that can effectively lift fluid and gas.

Gas lift by its very nature is excellent at dealing with the biggest problem that shale production has introduced – gas handling. Not only is it perfect for gassy wells, but it is also very effective at dealing with solids. This is because it eliminates the moving parts. In addition, the equipment is typically full tubing drift, therefore decreasing the possibility of failing equipment due to erosion.

ESPs and beams typically don't do very well with solids, and are prone to catastrophic failure. Additionally, Operators are in search of a different artificial lift method due to unconventional reservoirs yielding a wide range of production rates in a very short period of time. Because of these wide production ranges and the cost of working over a well, some operators sought out a lift type that could handle a wide range with a minimal amount of workover expense. Typical production rates can vary from 3,000 BFPD all the way down to 50 BFPD. Although gas lift has always been known for its wide range, recently there have been design changes that allow gas lifted wells to reach levels that can compete with a beam pump. The equipment paring in these systems allow for a change over to intermittent lift without needing a rig to do any work. To account for the rate changes mentioned above, ESP equipment would have to be changed at least once. In regards to beams, an operator would have to utilize two different pumping systems, since a beam would never be able to pump at the higher production rates.

Wellbore constraints are also a big factor when determining the artificial lift method that suits an operator's needs. Because of time-conscious drilling programs, many wellbores handed over to production teams are riddled with extreme doglegs. In some cases the dog leg severity (DLS) can be as high as 20°/100'. The DLS can occur anywhere; when DLS starts shallow or in the middle of the wellbore they make beam pumping difficult. When pairing extreme DLS with 5-1/2" casing, running ESPs is problematic.

While gas lift can mitigate typical downhole problems across the Permian Basin, operators need to supply low pressure gas to the compressor, and deliver high pressure injection gas to the wellhead consistently and cost effectively while balancing operability. Existing infrastructure, capital and long-term operations costs, and environmental considerations all play a role in selecting the best compressor for the job and keeping it running.

INFRASTRUCTURE AND INITIAL CAPEX

Existing infrastructure can play a pivotal role in determining which type of gas compressor is installed at a particular location. For electric-driven compression, operators will want to ensure the power grid is robust, reliable, and has capacity for future expansion. With the ever-increasing demand on area electrical power grids, and susceptibility to poor-weather outages, operators may find it more expedient and reliable to install gas powered compression at the sites instead. Although some electrical power is still required for off-skid metering, monitoring and data transmission regardless of compressor type, these requirements can often be supplied by solar panels and/or small wind generators. If close to the skidded compressor, electrical power can also be routed from the compressor batteries or alternator. The electric power costs for a gas-powered compressor are therefore significantly less than constructing a dedicated PME for an electric driven compressor. Competing demands for limited power (central tank batteries and salt water disposal facilities for example) may drive operators towards gas-driven compression for artificial lift, allowing for rapid field development without having to install additional electric infrastructure.

Both initial capital costs and long-term operations costs are important when considering gas compression options. Gas and electric options yield similar electric and gas powered compression costs. A common gas-powered engine, CAT 3306 TAA (turbo aspirated), coupled to an Ariel or CIP 3-stage compressor with on-skid Programmable Logic Controller (PLC), costs roughly $215M. A 200 HP Toshiba electric motor, driving the same 3-stage Ariel compressor with PLC costs approximately $230M. The surface infrastructure in the immediate vicinity of the compressor is similar for both options as well. A poly pipe low pressure gas supply line with meter, suction side and discharge side control valves, injection metering, high pressure injection piping, and automation/communications to suit the operating environment ranges $25M to $75M per well. Automation complexity, lengths of suction and discharge piping and labor charges are key variables in this evaluation.

OPEX CONSIDERATIONS

In terms of operating costs, three primary considerations are at play: reliability, power/fuel costs and maintenance. Many compressor companies quote gas-powered reliability as 97%, while electric-driven compressors are even higher, at 99%. Unfortunately, most operators do not realize these values, as the oil field operating environment is challenging. Overall gas lift system reliability is therefore reduced significantly (perhaps as low as 80%). In winter months, freezing condensates requires methanol, combination methanol and insulation, or methanol and heat tracing (depending upon desired level of protection). Consistent monitoring of operating conditions will allow early detection of abnormal conditions, while regular monthly maintenance of each unit will prolong compressor life and avoid more costly repairs.

Overall system reliability can be improved by placing several compressors in a centralized arrangement. As a general rule, 200 HP compressors yield 0.9MMSCFD, or enough gas to lift two horizontal wells. Installing slightly more compression than steady-state demands require (two compressors for three wells, for example) is a good practice. This ensures that, should a compressor drop off-line for maintenance or unforeseen difficulties, the gas compression loss is minimal and could be distributed among the total wells on the distribution system. This arrangement would further reduce well down-time and bring operators closer to the advertised reliability numbers. There are costs associated with a multi-compressor arrangement, however, including added complexity and longer high-pressure piping runs.

Maintenance, as a general industry rule, costs $120/HP/year to maintain a gas-powered compressor. The annual maintenance costs for a 200 HP model totals approximately $24,000/year, with fewer dollars spent early in life and progressively more dollars spent up to and including overhaul year(s). For 200 HP electric compression, third-party monthly maintenance costs are approximately $800 (or $9,600/year). Added to this, as mentioned earlier, electric driven compression has generally higher reliability than gas-driven, further reducing operating costs.

Power/fuel costs are also important to consider in long-term OPEX calculations.   Operators considering electric powered compression should calculate monthly power consumption using contract rates. Although rates are highly dependent upon the specific area, usage quantity, contract duration, etc., a nominal rate of $0.08/KW-hr is used for this example. A 200 HP electric-driven compressor would then cost $7,600 per month to operate. On the other hand, natural gas prices today remain low at $2.30/MMBTU. With a similar-size gas-driven compressor using approximately 40MSCFD in fuel, the monthly fuel cost is much less at $2,700. Finally, gas powered compression is beneficial if area gas sales options are limited. Using or storing produced gas for gas lift needs instead of expending CAPEX to deliver gas to third-party sales can be an attractive option.

ENVIRONMENTAL AND SURFACE USE CONSIDERATIONS

Operators should also evaluate emissions to ensure compression plans are environmentally responsible. Federal regulations prescribe a CO emission standard of 2.0 g/HP-hr for engines of 100 to 500 HP (NSPS, 1). Based on the advertised CO emissions for a 200 HP (CAT 3306 TAA) engine with Electronic Ignition Control System (EICS) of 0.5 g/HP-hr, operators could install four of these engines within a quarter mile before exceeding permit limits. These figures assume sweet gas, and continuous ops during the year with engines built 2011 or later.   Per regulations, engines must be tested “within 60 days of achieving maximum production rate but not later than 180 days after initial startup” to make sure they meet emission limits based on their type, HP, and manufacture date (NSPS, 2). This testing is typically conducted by compressor contractors or other third-party testing companies, and averages $2500-$3500 per compressor. The good news: experience shows that the actual emissions are often much less than advertised, which allows even greater density than four per quarter mile, if other conditions remain the same.

Operators should consider surface rights when evaluating gas compression installation. Clearing Rights of Way (ROWs) for high density polyethylene (HDPE) surface-laid supply gas lines, buried high pressure injection piping, electric power distribution, and compressor pads are not trivial exercises. Areas with additional Bureau of Land Management (BLM) constraints may find the additional surface equipment is cost or time-prohibitive. Surface-owned properties lend themselves most readily to gas compression installation, and permit the greatest flexibility with suction and discharge line-routing to minimize costs.

TRAINING

The last piece of the gas lift puzzle is providing proper training to the office surveillance team and lease operators. The approach must be methodical and thorough in order for employees to grasp these new concepts and procedures. The oilfield resists change, so an authority figure must be at the forefront of this directive in order for employees to accept that gas lift will be coming into their area.

Employees should be exposed to the concepts of gas lift early and often. To help retain these concepts, they should be given every opportunity to train around the equipment in the field – any overtime incurred is well worth the cost when the gas lift operations kick into full gear. The equipment and the method of operation are different than a beam unit or ESP, but employees will learn the personalities of the gas lift wells and in time make them produce to their fullest potential.

The training program developed by an operator can be aided by gas lift vendors, subject matter experts, or outside consultants. It should be started as soon as possible, be conducted weekly, be less than 30 minutes for each module, have a 5 minute recap from previous modules, and allow for questions/discussion. This structure will allow for engaged employees to ask questions and share their experiences while providing repetitiveness so that employees retain the knowledge shared. Visual aids and cheat sheets are encouraged so that employees can build a library of references.

The material should be covered in modules (explained above) and contain the following subjects at a minimum:

1. Oilfield Processing Facilities – general overview of processing facilities to make sure employees are on the same page and ready for the upgrades that will be coming to their facilities.
2. Gas Scrubber and Gas Distribution System – the first piece of equipment in sending clean, dry gas out to the gas lift units. Must include the size, pressure and throughput of the operator's typical scrubber and where liquids and gases subsequently move. A review of the distribution system and the piping specification is helpful.
3. General Compressor Theory – technical aspects of compression ratios, compressor types and respective rates, pressures and temperatures. Should include properties of natural gas and how this can affect the overall compressor package.
4. Gas Lift Unit Overview – packaging compressors and engines, the workings of the engine, inlet scrubbers and associated equipment, gas coolers, and typical engine rpm. A review of pressures, temperatures and capacity for the whole unit.
5. From Gas Lift Unit to Wellhead – discharge piping and pressure protection, gas metering, flow control equipment, data collection, communications and associated automation.
6. The Wellhead – tubing and casing connections, pressures and valving.
7. Downhole – technical aspects of the tubing, packer, gas lift valves and the general flow path of the wellbore equipment.
8. Normal Operating Conditions – specific to the operator, determined by the asset development team and artificial lift group.

Establishing a good foundation of knowledge is important, so it is imperative to seek feedback about how the team is absorbing and processing the information. Trainers should tailor the training program to fit operators' needs. This can be achieved by administering a short quiz at the beginning or end of each module to give the trainer, supervisor, or engineer a feeling of how the training should be adjusted before the next module.

Once the lease operators begin working around the gas lift operation, they will need training in the following areas:

1. Equipment Set Points – engine rpm, flow rates, pressures and temperatures.
2. Wellhead Specifics – flow rates and pressures.
3. Well Testing – expected results, setting up and operating a two pin chart (or similar automation) for tubing and casing readings, interpreting and understanding tubing and casing pressure trends.

The training should never stop, and the pace of these additional modules should be determined by your employees. Each new module is an opportunity for employees to ask questions that the entire group will benefit from. Engaged employees should find themselves leaning on the knowledge gained in the initial 8 modules and making inferences and educated assumptions about how and why their equipment is responding the way that it is.

As employees enter the organization or move around within the organization, it will be important to continue training in order to keep a level of acceptable competency. Once the curriculum is set and employees get in a rhythm, this will not be the time-consuming task it appears to be.

OPERATING PRACTICES AND SURVEILLANCE

The descriptions below describe the duties of a lease operator for each of the major forms of artificial lift in the Permian Basin:

> Beam – visually inspect the unit and control boxes, listen for abnormal noises, check the wellhead for leaks, check polished rod for alignment, check pressures on tubing and casing (preferably while pumping), check for fluid being brought to surface, make sure the polished rod is lubricated, and record tester readings.
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> ESP – check if it is running, visually inspect the electrical equipment, check the wellhead for leaks, check pressure on tubing and casing, check for fluid being brought to surface, and record tester readings.
>
> Gas lift – visually inspect the engine and compressor, listen for abnormal noises, check the gas flow control and metering equipment for appropriate readings, check the wellhead for leaks, check the two pin chart/automation, and record tester readings.

Depending on the operating procedures of a company, the lease operator may or may not be heavily involved in the office-based surveillance of wells. An office surveillance team might take much of the responsibility, and can expect the following from their wells based on these descriptions:

> Beam – drawing good surface and downhole cards, counterweight in balance, daily run times and cycles are appropriate, calculated fluid level trends are in range, minimum and maximum surface loads indicate no downhole issues, and well tests are acceptable for given beam activity.
>
> ESP – yesterday's and today's run times and cycles are as expected, and well tests are acceptable for given ESP activity. Check amperage, hertz settings, and pump intake pressure (PIP) trends/charts.
>
> Gas lift – yesterday's and today's total gas volumes and flow rates are in range, pressure and temperatures are acceptable, two pin chart (or automation) is recording as expected, and well tests are acceptable for given gas lift activity.

MAINTENANCE

ESPs have no maintenance to speak of. Beam units and gas lift units require about the same amount of maintenance in terms of a total program. In-house maintenance by company personnel could require significant additional resources, as compressor numbers ramp up to satisfy full-field needs. Alternately, several third-party companies offer maintenance contracts, including most compressor manufacturers. Starting with a third-party maintenance contract and transitioning to an in-house capability could be a viable option for operators who wish to gradually move into the gas compression arena while minimizing risk.

The following descriptions provide an insight to the regularly scheduled maintenance on surface equipment:

Beam –	Daily – tighten or replace loose or missing bolts, check belts
	Monthly – check gear box and bearings
	Quarterly – check brake, sheave, brake drum, brake cable, crank phase marks
	Annually – change gear box oil, grease bearings, inspect wireline, tighten bolts
ESP –	None
Gas Lift –	Daily – tighten or replace loose or missing bolts, check lube oil

Monthly – check belts and air filter

Quarterly – change oil and filters

Bi-Annually – inspect valves

CONCLUSION

Gas lift is becoming a preferred artificial lift type across the Permian Basin, as well as in other areas. This paper discussed reasons for converting to gas lift, and how to select the best candidates for lift conversion. The topics of GOR, deviated wells, solids handling, and typical production rates were discussed, as well as comparing gas lift to other popular lift types' efficiency and range. Surface considerations also play a pivotal role in gas lift installations; electric infrastructure, gas availability, and environmental considerations are also discussed. In the final section, operating practices, maintenance, training, and personnel costs are discussed, with comparisons to other lift types. Armed with this information, operators can succeed in bringing gas lift to bear, avoiding pitfalls and succeeding in overcoming associated challenges in bringing 'gas lift into a beam world'.

REFERENCES

1. 40 CFR Part 60, Standards of Performance for new Stationary Sources, Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines), Table 1.
2. 40 CFR Part 60, Standards of Performance for new Stationary Sources, Part 60.8d (Performance Tests).

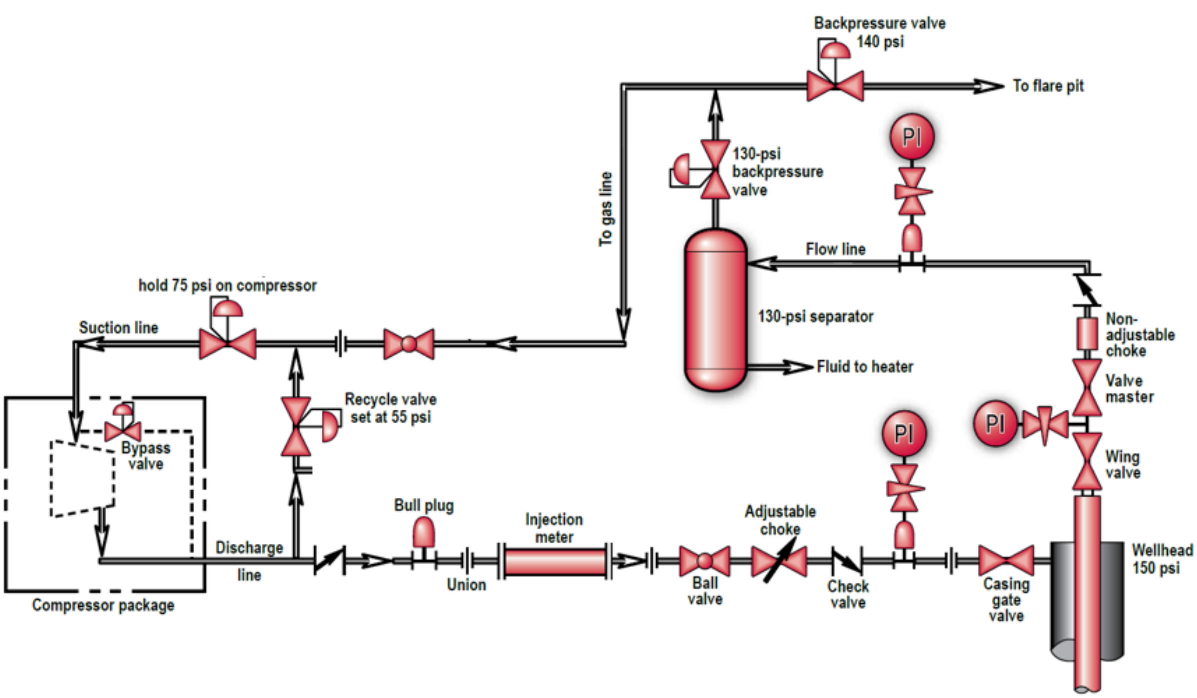

Figure 1: Basic Low pressure to High Pressure Gas Lift Surface Schematic

Table 1: Applicability of Artificial Lift Methods					
Condition	Rod Pumps	Hydraulic Pumps	PCP's	GL	ESP's
Scale	fair	fair/poor	fair	fair	poor
Sand	fair	very good	good	very good	fair
Paraffin	poor	fair/poor	good	poor	food
Corrosion	good	fair/poor	fair	fair	fair
High GOR	poor	fair	fair	very good	fair
Deviation	poor	very good	fair/good	very good	good
Rate	poor	fair	fair	very good	good
Depth	fair	very good	fair	good	fair
Flexibility	very good	very good	good	very good	good
Temperature	very good	good	poor	good	fair