GALLOP INTO LATE-LIFE PRODUCTION: EXTENDING WELL LIFE BY UNLOADING FROM THE LATERAL

Ryan Hieronymus
Occidental

Scott Wilson
Ryder Scott LLC

David Green
Well Master Corp

ABSTRACT & INTRODUCTION

Thousands of horizontal wells drilled during the U.S. unconventional boom are now well into their second decade of production. As reservoir pressure depletes, many are beginning to exhibit premature liquid loading. Conventional artificial lift systems such as rod pumps, electrical submersible pumps (ESPs), and traditional gas lift often only unload fluids from approximately 30- to 45-degree inclinations, leaving several hundred vertical feet of separation between the end of tubing (EOT) and the productive perforations in the lateral. Many aging wells can no longer sustain critical velocity to carry liquids up the wellbore through this interval. This ‘heel loading’ leads to liquid accumulation in the build section, which chokes off production despite remaining reserves.

Gas Assisted Liquid Lift Oscillating Pressure (GALLOP) is a new variant of gas lift and addresses this challenge by unloading liquids from a selected accumulation point in the lateral. The system uses concentric tubing (jointed pipe or coiled tubing) with a downhole check valve to regulate fluid entry into the tubing system and is run into the horizontal section. The system operates in cycles with two main operational phases: In the fill phase, formation pressure opens the downhole check valve and allows fluid entry into the tubing system. Then, in the injection phase, gas is injected down the concentric tubing annulus causing the downhole check valve to close, and fluid in the tubing system to be lifted to surface. This isolation of the tubing system from the wellbore via a check valve, combined with intermittent gas injection, creates a higher-pressure closed lift system that is isolated from a lower-pressure wellbore, which enables production at very low reservoir pressures. This paper documents the first live pilot of this system in the Denver-Julesburg (DJ) Basin. The pilot well was a mature horizontal well that had become a plug-and-abandonment candidate due to liquid loading and low reservoir pressure. Pilot results demonstrate GALLOP's capability to extend well life and unlock stranded production from an aging horizontal well.

CONCEPT OVERVIEW

The original concept of GALLOP started in the early 1960s when one of the authors was trying to determine how the water in the bottom compartment of his parents’ espresso maker ended up in the top compartment. Fifty years later, horizontal wells are struggling to lift liquids that naturally accumulate in sumps and uphill sections of horizontal wellbores. Production and video logging studies have shown that liquids accumulate in sumps or in sections where fluids must move upwards against gravity, and gas flows preferentially over accumulated liquids (Sask et al. 2007). A study of over 1,000 Marcellus and Utica horizontal wells with available directional surveys found that 82% had at least one 'trap' in their laterals, and that undulating horizontal wellbores lead to complex slugging dynamics in multiphase flow (Sutton et al. 2012).

It is common knowledge that artificial lift options able to lift around the heel of a well are limited. Even when rod lift systems or ESPs are successfully installed deep in the build, high wellbore inclination often leads to challenges with downhole gas separation and premature failures. These pumps also generally have higher minimum flowrate requirements that can render them unsuitable for the low production rates associated with late-life production. With few other options for lifting low-rate horizontal wells from the lateral, GALLOP was designed to take advantage of the long horizontal section by using a concentric or dual tubing system installed into the lateral as an accumulator, with a screened inlet check valve to allow fluid entry into the tubing system (Wilson 2013). The tubing system is isolated from the wellbore other than through the check valve. Figure 1 illustrates the deployed concentric tubing architecture and screened intake location within the horizontal section.

The system operates in two main phases: fill and injection. During the fill phase, the production casing annulus and tubing system are both open to surface. Liquid and gas flow from the reservoir through the perforations into the lateral. Any gas produced during this period is allowed to flow up the production casing annulus to the production separator, while liquid falls back and settles into the low points in the horizontal section. From there, the liquid enters the tubing system through the screened downhole check valve. The potentially large accumulation volume associated with the concentric or dual tubing system does not increase in pressure as it fills with liquid, since there is no increase in hydrostatic head and it is open to the production separator at surface. The length of the accumulation pipe in the lateral can be used to carefully control the volume collected during each fill phase, reducing the likelihood of a dead-head or stymied lift condition.

Once a sufficient 1-2 bbl liquid load is collected into the tubing system from the targeted section of the horizontal portion of the wellbore, the fill phase ends and the second phase begins: the injection phase. During the injection phase, injection gas from the surface is applied to one side of the concentric or dual tubing system. The injected gas supplies pressure to close the downhole intake check valve and lifts the accumulated slug to the surface. After the slug arrives in the separator, injection gas is stopped, and both sides of the tubing system are blown down to the production separator. As the injection-side tubing pressure falls, it allows the downhole check valve to open and the system to re-enter the fill phase. The process is very similar to using compressed air to winterize a sprinkler system.

The two main phases of a GALLOP cycle (fill and injection) can be further broken down into four operational stages:

1. Fill: the downhole check valve is open and liquids enter the tubing system
2. Gas injection: the check valve closes and the lift conduit pressurizes
3. Liquid production: injection continues and the accumulated slug is displaced to surface
4. Pressure blowdown: injection ceases and the tubing system depressurizes to re-initiate fill.

A simple surface control scheme can be implemented using a timer-based controller and three primary surface control valves (CV), allowing repeatable cycling without complex downhole actuation. Figure 2 displays a simplified production tree schematic with the control valves that are used to control GALLOP operation. Figure 3 summarizes the four-stage cyclic unloading process.

DOWNHOLE EQUIPMENT DESIGN & TESTING

A primary design objective of the GALLOP pilot was to minimize downhole complexity, which is necessary to improve reliability in late-life wells where intervention costs are high and wellbore access may be limited. The field-deployed GALLOP configuration evolved from early "flatpak" dual-line concepts into a concentric tubing system, which provides improved practicality, availability, and deployment reliability. In the concentric design, an outer tubing string is intermittently pressurized while an inner tubing string provides the primary produced-liquid flow path to surface. A screened intake and check valve assembly is installed on the outer tubing at the targeted accumulation point in the horizontal section. This configuration is particularly suited for unloading from low points in the lateral where conventional lift systems cannot effectively sweep liquids up the several-hundred-foot interval between perforations and the end of tubing. The concentric GALLOP geometry establishes two distinct hydraulic regions:

- A pressurized concentric tubing annular volume used during the injection phase
- A central production conduit through which liquid slugs are displaced to surface

The GALLOP system required the development of a downhole screened inlet check valve assembly capable of reliable cyclic operation while deployed deep into the horizontal section of a mature well to allow fluid to enter the otherwise isolated tubing system. The GALLOP lateral assembly contains very few moving components, with the intake check valve representing the only dynamic element below surface. This check valve is the critical interface between the wellbore and the lift conduit; it opens during the fill phase to allow fluid to enter the tubing system, and it closes under injection gas pressure during the injection phase to isolate the accumulated slug for displacement to surface. Figure 4 shows a diagram of the downhole check valve assembly.

Because GALLOP depends on repeated cyclic operation, check valve durability and solids tolerance were identified as primary technical risks. To address this, an automated valve qualification test loop was designed and built to simulate downhole GALLOP cycling conditions. Nine commercially available check valve models were tested with this apparatus, including ball/seat and poppet-style designs with metal-to-metal and elastomeric seals. During testing, these check valves were repeatedly subjected to:

- Flow of a sand slurry representative of produced solids
- Differential pressure sealing to approximately 1,400 psi
- Rapid depressurization and cycle repetition under accelerated wear conditions

Cycle-to-failure results are summarized in Table 1. Commercial valve testing demonstrated wide variation in durability, with the best off-the-shelf option failing after approximately 7,000 cycles (equivalent to roughly nine months of typical GALLOP operation). To achieve reliability suitable for pilot deployment, a custom check valve was developed incorporating the most successful design features identified during failure analysis of the tested commercially available check valves. The custom valve demonstrated substantially improved endurance during qualification testing; the test was halted after the valve exceeded 17,000 cycles without failure (approximately two years of typical GALLOP cycling).

In addition to the downhole equipment, a custom tubing head was developed to facilitate the installation of the dual tubing system at surface on the pilot well. A concentric tubing system of jointed pipe was selected for the pilot (as opposed to concentric coiled tubing) to minimize workover complexity and cost. 1.315" outer diameter (OD) inner tubing was selected for use inside 2-3/8" production tubing. The 2-3/8" production tubing was terminated with a bull plug, ensuring that all fluid entry into the tubing system would be through the 2-3/8" screened intake mandrel assembly.

SURVEILLANCE & CONTROL SYSTEM DEVELOPMENT

GALLOP performance is governed not only by downhole equipment but also by surface surveillance and control of the cyclic unloading process. Effective operation requires appropriate cycle timing, injection pressure management, and production confirmation across each of the four stages of operation. The DJ Basin pilot emphasized maximum surface flexibility, measurement of key parameters and access for monitoring, control and data downloads for further analysis. Pressure monitoring points include the production casing annulus, concentric tubing annulus, and inner tubing, while injection rates and produced gas rates are measured with orifice meters. Gas and liquid production are routed through a dedicated three-phase separator to observe unloading response. All of these parameters are fed into a programmable logic controller (PLC), for use in optimization.

Remote control capability allows the adjustment of cycle timing, management of flow paths, and optimization of injection rates as operational understanding improves. The remote connectivity of the controller provides real-time updates from the field, with data resolution as frequent as one-second intervals for pressure data. The controller can be accessed through a proprietary, secure cellular-based access-point-name (APN) virtual private network (VPN) from anywhere with an internet connection.

CANDIDATE WELL EVALUATION

In mid-2021, 'Candidate Well A' in Larimer County, CO, was selected to trial the GALLOP system. Candidate Well A produces from the Codell Formation at ~7,200' total vertical depth (TVD) and was in close proximity to existing pad gas lift compression infrastructure. The well was experiencing persistent liquid loading following an ~18-month shut-in for surface facility maintenance. Attempts to return the well to production with gas-assisted plunger lift (GAPL) proved challenging, leading to an additional ~2.5 years of inconsistent, highly labor-intensive production.

An inflow production test was completed with temporary gas lift injection from surface around the end of tubing (no gas lift valves or packer) and was able to confirm a reservoir pressure of less than 700 psi. During the inflow test, it was observed that production was only possible when the injection pressure was very low; higher injection pressures led to gas circulation with no liquid production. This confirmed the well was loading in the heel. When injection pressure was low, it enabled fluid to successfully be produced at a rate of just over 20 barrels of liquid per day (BLPD) with temporary continuous gas lift. Although the temporary gas lift inflow test indicated that production with continuous gas lift was barely possible, the low liquid rates and high susceptibility to heel loading indicated that a conventional gas lift installation would be short-lived. Other than GALLOP, the only true option for the well would have been plug and abandonment (P&A) due to persistent downtime and lack of production without significant manual operation.

Outflow with the GALLOP system was modeled for Candidate Well A with a custom slug & cycling calculator, which predicted the system outflow to be capable of more than 30 BLPD with the candidate well configuration, and up to ~40+ BLPD with other configurations. Since the inflow test rate (just over 20 BLPD) was lower than the calculated GALLOP outflow rate, the inflow rate of just over 20 BLPD was used in economic evaluation as the expectation for system performance.

A high-resolution downhole survey was conducted to explore the well for an optimal set depth. As shown in Figure 1, Candidate Well A is slightly toe-up, with several undulations and low points. A set depth for the 2-3/8" outer tubing bullplug EOT was selected around 370 ft into the lateral. The screened check valve mandrel assembly was set ~190 ft measured depth (MD) shallower than the EOT (~180 ft into the lateral). The inner 1.315" tubing was set ~15' MD toward the toe from the mandrel (~195 ft into the lateral).

Candidate Well A is in an area prone to paraffin, creating concern that a paraffin plug could form in the smaller GALLOP flow conduit. This would leave few options for remediation, since the GALLOP flow conduit is too small to remove paraffin with common wireline tools. To mitigate this risk, paraffin inhibitor is pumped into the system with the injection gas. This paraffin inhibitor is injected directly into the isolated GALLOP tubing system and mixes with the liquid slug in the bottom of the system where the temperature is above the fluid's wax appearance temperature. This prevents paraffin formation as the slug is lifted to surface and passes through cooler temperatures shallower in the wellbore.

An additional concern during pilot evaluation was the potential to hydraulically lock during the injection phase if a tall slug was to enter the vertical portion of the tubing system. The GALLOP system has no unloading valves in the vertical section, so the entire liquid slug must be able to be lifted to surface utilizing only the differential between available surface injection pressure and expected wellhead backpressure (~1,200 and 200 psi respectively). Assuming production up the 1.315" inner tubing (0.00107 bbl/ft capacity), a slug could be no larger than ~2.5 bbl before the height of the liquid column created too much hydrostatic pressure to lift. To increase flexibility on the pilot well, the production tree was designed to facilitate reverse circulation with GALLOP (injection down inner tubing, production up tubing annulus). The increased flow area in the concentric tubing annulus increased the liftable slug volume from ~2.5 bbl to ~6.5 bbl. To handle the worst-case scenario where a liquid slug was larger than 6.5 bbl, a connection point on the injection side of the production tree to rig up high-pressure compressed natural gas (CNG) is available, but it has never been needed other than during initial kickoff.

PILOT INSTALLATION & PERFORMANCE REVIEW

Prior to installation, a wellbore cleanout was performed about 800' into the lateral, past the first few frac stages. This was intended to minimize risk of solids interacting with the check valve assembly. Due to the low reservoir pressure, the well was unable to support a column of fluid, and a vectored annular cleaning system (VACS) tool had to be utilized to enable cleanout operations without returns to surface. The cleanout did not recover any meaningful debris, indicating a lower probability of solid interference with the downhole check valve assembly. During installation, it was identified that no mule-shoe style bottomhole assembly (BHA) existed for the 1.315" inner tubing that would comfortably drift through the downhole check valve assembly, so an ordinary piece of 1.315" tubing was cut mid-body at an angle to replicate a mule shoe. This enabled the inner tubing to be installed at the intended set depth, ~15' deeper than the check valve assembly.

Candidate Well A initially returned to production with GALLOP in July 2022 at just over the ~20 BLPD target production (determined based on inflow testing), proving that the GALLOP system can deliver the required rate from an outflow perspective. From an inflow perspective, Candidate Well A exhibited faster decline than expected, declining to rates of less than 5 BLPD within the first 9 months of GALLOP production. After the initial decline, production stabilized at rates of only 2 to 5 BLPD and associated gas.

The GALLOP system remains fully operational in early 2026 and is now approaching four years of reliable, low-rate production. It has proven to be remarkably resilient, surviving multiple shut-ins for offset frac operations and associated pressure communication events. Production has been easily restored even after extended downtime periods related to offset activity. While in operation, it has required very little (if any) extra effort from the Operations team and is generally considered a low-maintenance well. The paraffin inhibition strategy has proven effective, with no downhole paraffin-related issues since the beginning of the trial.

Other than initial startup when the GALLOP system was full of fluid following the rig work, CNG has never been required to lift a large liquid slug; the system has always been capable of unloading itself using only the normally available surface injection pressure. There were several downtime events that led to medium-sized slugs entering the tubing that could not be lifted up the inner tubing, but these were easily removed after switching to reverse circulation with GALLOP. Following the second such event, the decision was made to operate the GALLOP system in reverse circulation mode as normal course of business for the pilot well. Since that time, no manual operation has been needed to clear the system of liquid.

Upon further consideration, the 5-day inflow test originally performed to assess the quality of Candidate Well A was likely not long enough to distinguish between true inflow and wellbore storage, leading to an overestimation of productivity (production rates of around 20 BLPD during the test did not produce a full lateral volume's worth of fluid). Due to the longevity of stable production after the initial decline, the issue is suspected to be inflow related as opposed to outflow related. Any flow assurance problem that would inhibit flow from the lateral into the tubing system would most likely have continually worsened until production was fully choked off from entering the tubing system. Figure 5 shows the production history of Candidate Well A with the GALLOP system.

Initial pilot experience demonstrated that short, frequent cycles with approximately balanced fill and lift times produced the most stable unloading response. Lift time was governed by observed liquid recovery, while fill time often required extension due to low inflow rates characteristic of the late-life, low-reservoir-pressure pilot well. Pilot operations also highlighted several practical requirements for scalable deployment:

- Adequate and stable lift gas pressure and on-demand volume
- Improved surface surge capacity for both injection and produced gas
- Simplified operational workflows for field personnel
- Robust downstream facility handling to prevent "reset" interruptions
- Wide gas measurement range is preferred – separator gas rates can be very low during the fill phase and very high during depressurization

Figure 6 provides representative pilot cycle performance illustrating the wide range of pressures and gas flowrates experienced within a single GALLOP operational cycle.

Candidate Well A shares a pad compressor with four other horizontal gas-lifted wells. The other wells are also low producers and utilize plungers (GAPL). They operate with low continuous surface injection gas rates at low injection pressures and are not generally impacted by the high initial gas rate drawn by the GALLOP well when it begins its injection phase. If more than a single GALLOP well shared a pad compressor without an accumulator for injection gas, it may create additional challenges to ensure the system could deliver very high instantaneous injection rates immediately at the beginning of GALLOP injection phase. To mitigate this, controller logic could be expanded to ensure that injection cycles do not immediately align. This is not expected to be an issue for any GALLOP well on a centralized gas lift system, because centralized systems generally have much higher well counts that serve to dampen the impacts caused by the operation of any one well. Additionally, the pilot highlighted the importance of precise valve operation; control valve 2 must fully close before control valve 3 opens to ensure injection gas does not have a direct path to the production separator.

The pilot confirmed that GALLOP can be operated safely and effectively with real-time surface transparency. The control platform provided operators and engineers with immediate feedback on injection response and unloading success, enabling rapid learning and refinement of cycle settings. While early deployments were operator-supervised, the GALLOP method is inherently suited for automation through programmable logic based on pressure thresholds, slug arrival detection, and adaptive cycle frequency as reservoir pressure declines.

CONCLUSION & THOUGHTS ON BROADER APPLICABILITY

In summary, the DJ GALLOP pilot has successfully extended the life of Candidate Well A by about 3.5 years and counting. Candidate Well A ended up not being as productive as initial testing indicated, but initial rates with the system provided proof-of-concept with regard to modeled outflow delivery, and the reduced rates after the well declined provide proof that the system is capable of enabling production at very low liquid rates. The steep production decline appears to be entirely related to inflow and reservoir productivity, and does not appear to be related to the well's outflow.

The DJ GALLOP pilot was the culmination of years of collaborative technical work, design reviews, and equipment prototyping and testing. Everything from the downhole screened intake mandrel to the custom tubing head and production tree was developed specifically for this pilot. While the DJ pilot's total initial installation cost was on par with that of a typical small pumping unit installation, the run life of the GALLOP pilot has far exceeded that of a typical pumping unit, leading to much lower average operating costs. Future installations will likely be less expensive due to the following factors:

- Designs are now established, as opposed to being developed and prototyped
- Less investigatory work will be needed on non-pilot wells (high-resolution surveys)
- Scaled manufacturing of components will drive down unit cost

As horizontal wells across U.S. onshore continue to age, heel loading will become an ever-increasing challenge. GALLOP is a viable solution to address this, especially anywhere existing gas injection infrastructure is in place.

REFERENCES

Sask, D., Hundt, C. D., Slade, J. M. et al. 2007. Production and Video Logging in Horizontal Low-Permeability Gas Wells. Presented at the Rocky Mountain Oil & Gas Technology Symposium, Denver, Colorado, USA, 16–18 April. SPE-108084-MS. https://doi.org/10.2118/108084-MS

Sutton, R., Sarica, C., and Chase, B. 2012. Marcellus & Utica Shales: Implications for Liquid Loading. Presented at the 3rd Annual Appalachian Basin Gas Well Deliquification Seminar, Marietta, Ohio, USA, 4–6 June. Available from the Artificial Lift Research and Development Council (ALRDC), https://alrdc.com.

Wilson, S. J. 2013. Method and Apparatus for Removing Liquid from a Horizontal Well. U.S. Patent Application Publication No. US20130098629A1. United States Patent and Trademark Office. https://patents.google.com/patent/US20130098629A1/en

TABLES & FIGURES

Table 1 - Check valve test results

Valve Model	Style / Seat Type	Cycles to Failure	Equivalent GALLOP Life (mo)
Mfr. 1, Model 1	Ball, metal seat	650	0.9
Mfr. 1, Model 2	Poppet, Viton seat	650	0.9
Mfr. 2, Model 1	Ball, EPDM*/metal seat	21	0.0
Mfr. 2, Model 2	Ball, Viton/metal seat	2,762	3.9
Mfr. 3	Ball, Viton/metal seat	253	0.4
Mfr. 4, Model 1	Poppet, Viton seat	0	0.0
Mfr. 4, Model 2	Poppet, Viton seat	0	0.0
Mfr. 5	Poppet, Viton seat	330	0.5
Mfr. 6	Ball, Viton/metal seat	6,885	9.7
Internally developed custom check valve		17,000+ (no failure)	24+

*EPDM: Ethylene Propylene Diene Monomer

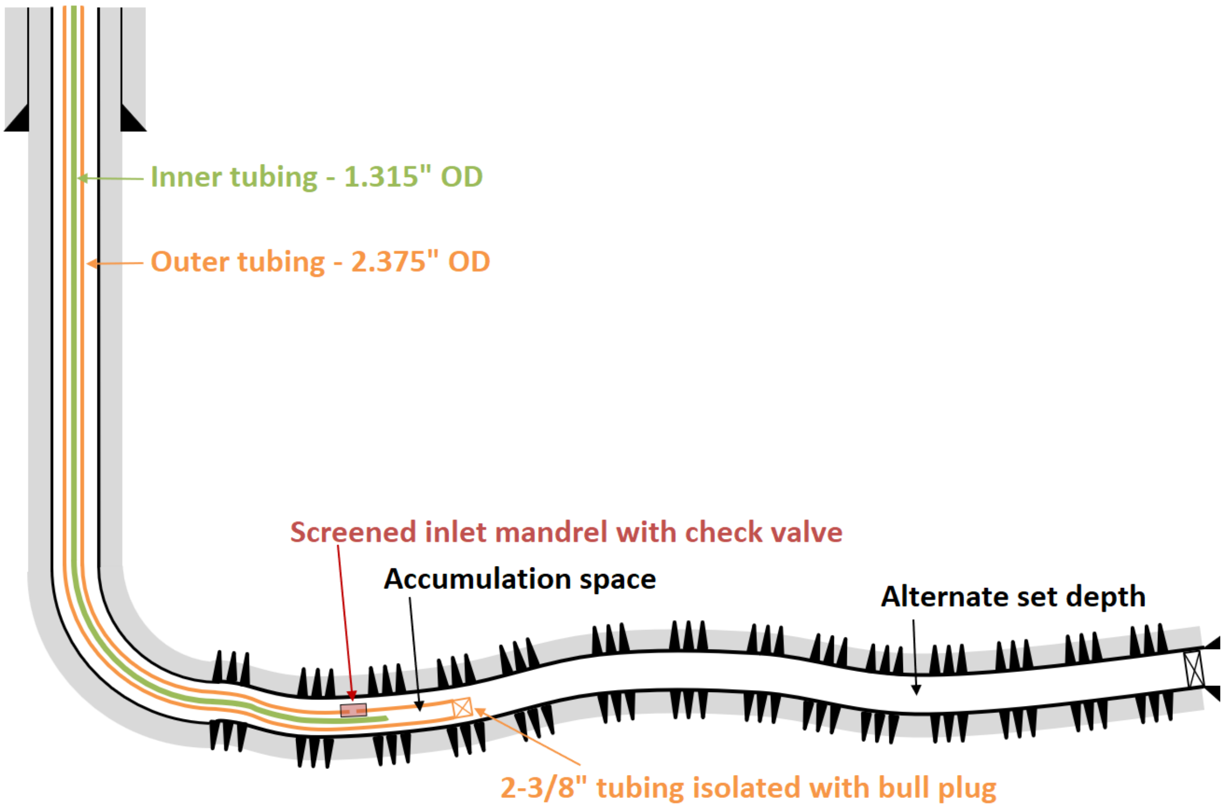

Figure 1 - GALLOP schematic - concentric tubing design with screened intake

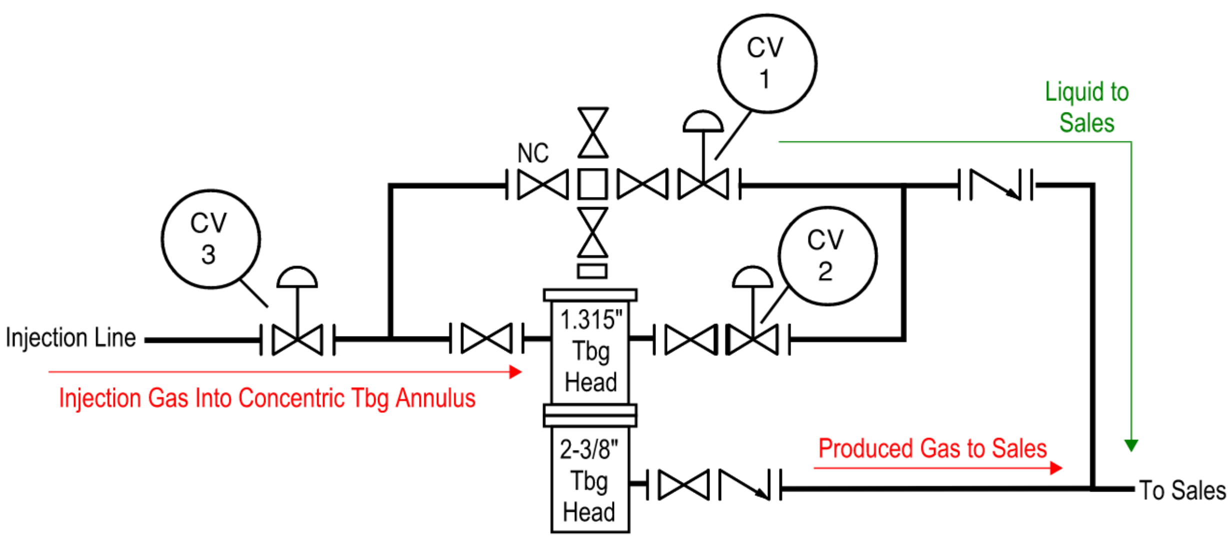

Figure 2 - Simplified rendering of GALLOP production tree

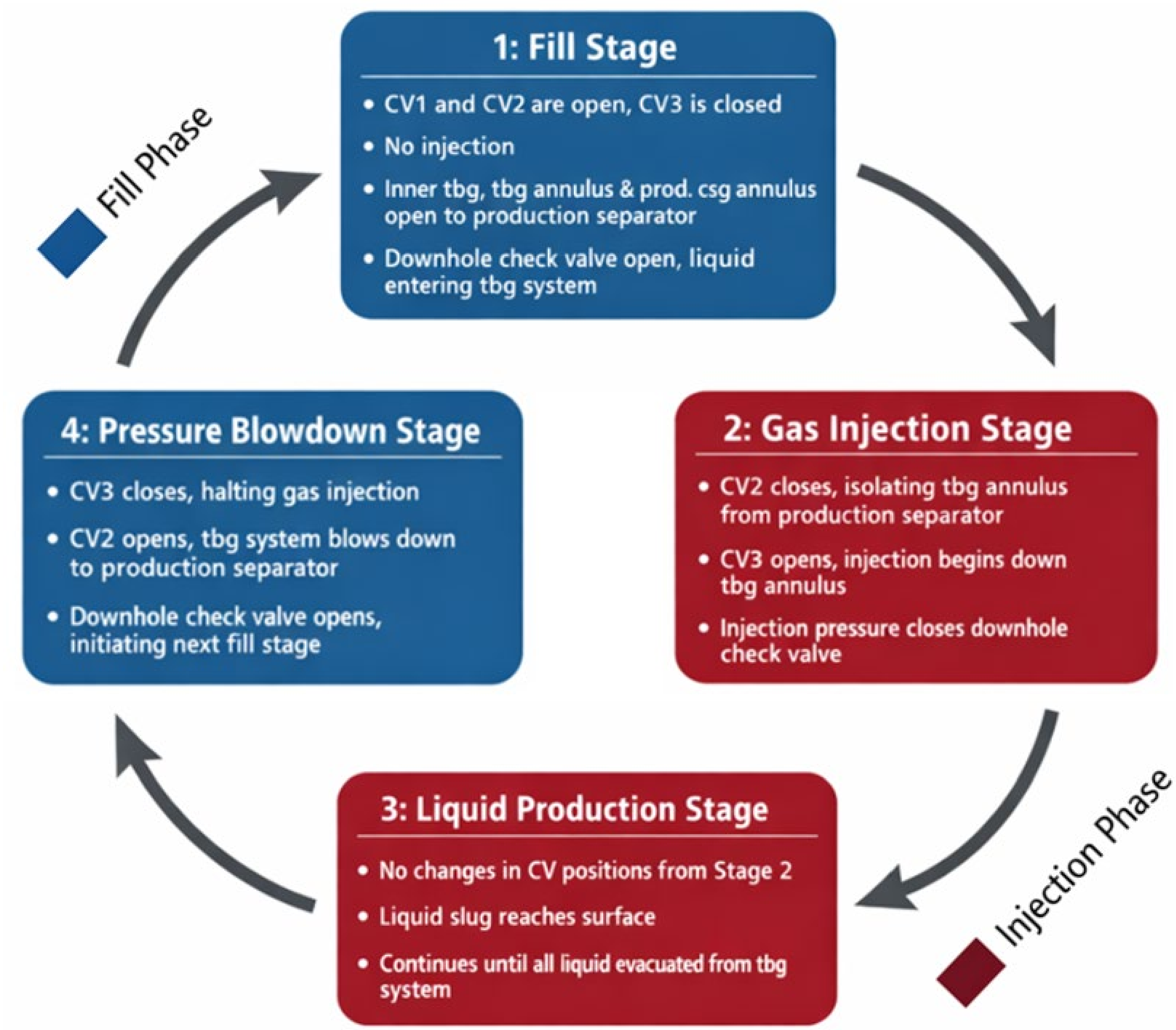

Figure 3 - GALLOP stages of operation

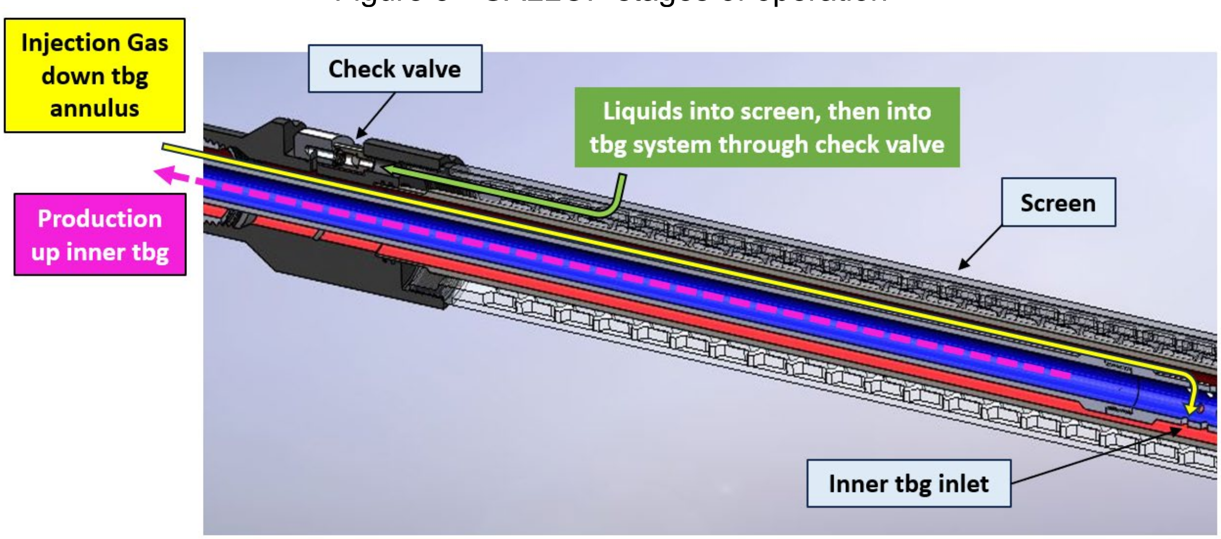

Figure 4 - Schematic of downhole screened intake and custom check valve integration

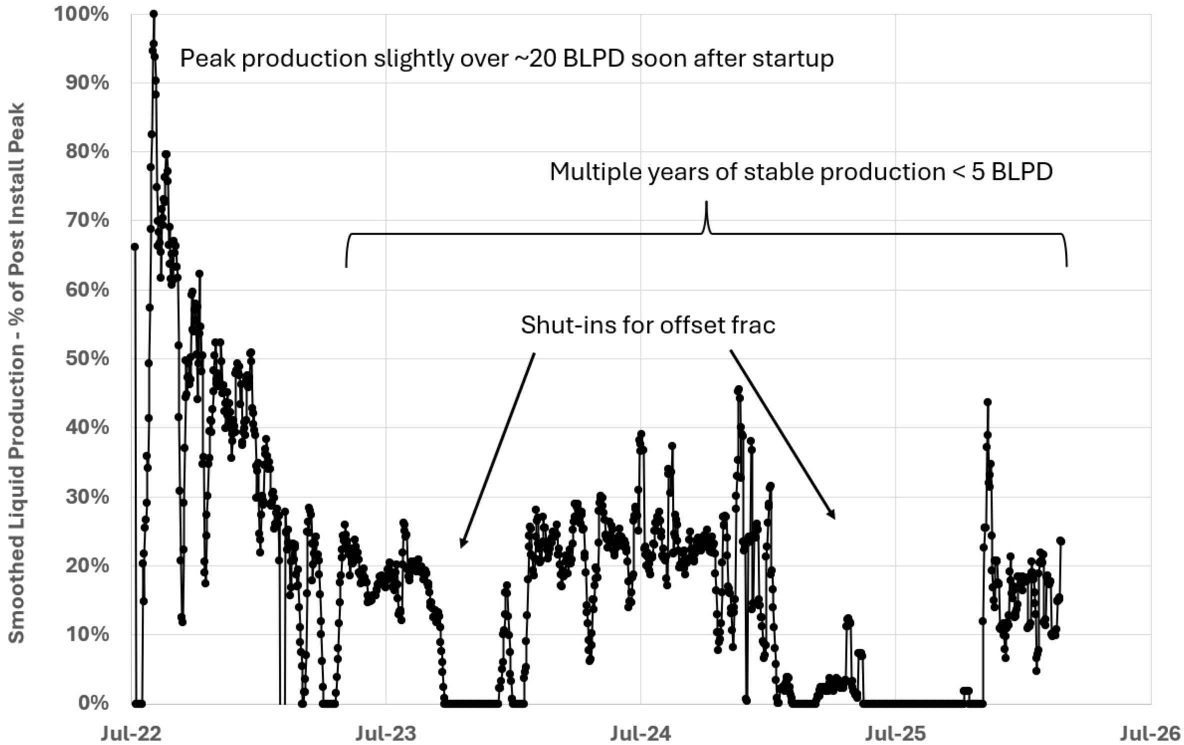

Figure 5 - Candidate Well A production history with GALLOP

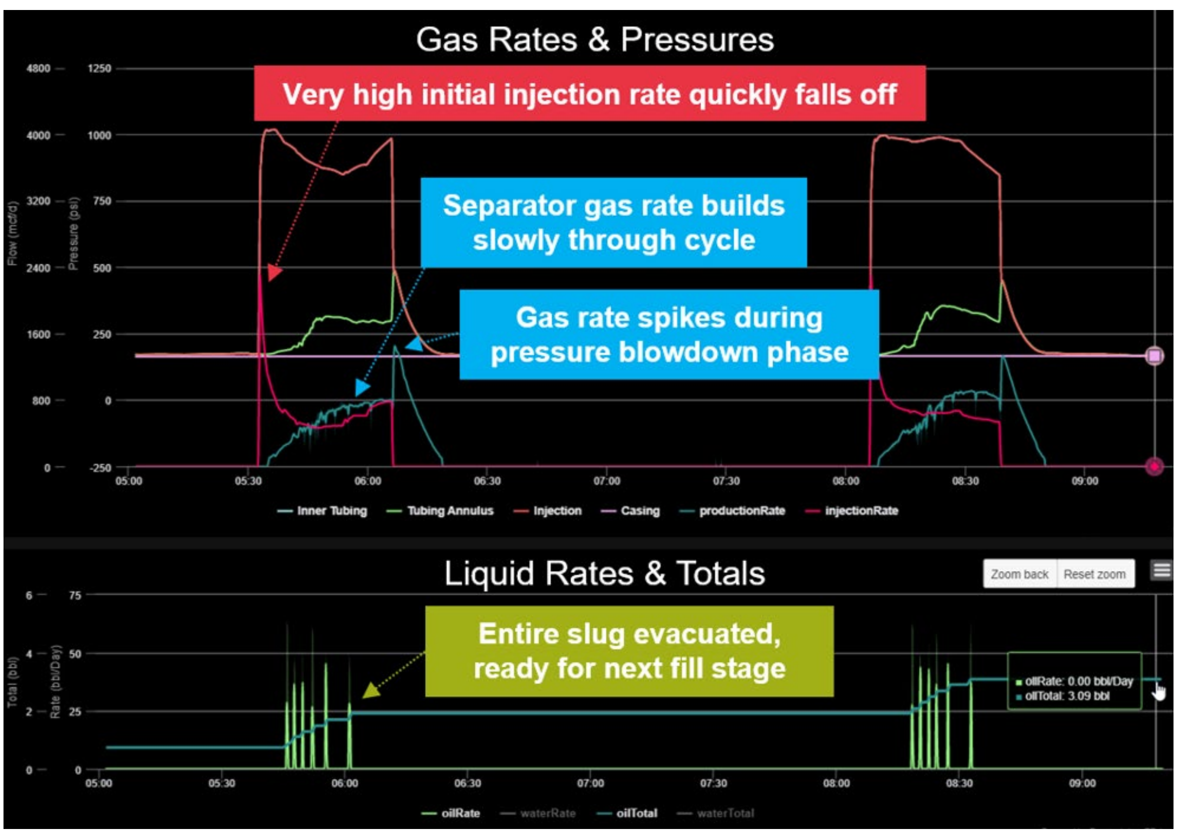

Figure 6 - Representative cycle performance