DISSOLVABLE PACKERS: ENABLING DAY-ONE GAS LIFT INSTALLATIONS AND ESTABLISHING AN INTERVENTION-FREE WELL CONTROL STANDARD IN HIGH-PRESSURE DELAWARE BASIN WELLS – FIELD RESULTS FROM MORE THAN 125 INSTALLATIONS

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ABSTRACT

Traditional well control methods for high-pressure annular gas lift installations in the Delaware Basin have involved the use of kill fluids or mechanical packers, resulting in increased operational costs, risks, and non-productive time (NPT). Historical practices included kill fluids (applied in approximately 70% of operations), mechanical packers and plugs (approximately 20%), and snubbing operations (approximately 10%). These approaches incurred higher costs, formation damage risks, intervention requirements, and delayed production onset.

An alternative approach was implemented using a Dissolvable Packer as temporary well isolation tool designed for pressure control during gas lift installations. The packer provides reliable sealing without foreign fluids or subsequent mechanical retrieval required. Dissolution occurs predictably through reaction with wellbore fluids, eliminating retrieval interventions and associated risks, costs, and NPT.

The packer's design enables installation of gas lift equipment on day one while preserving the option to initiate artificial lift when required. Following the expenditure of an internal dissolvable pump-out plug, flow is established with full wellbore ID available upon packer dissolution. Field application across more than 125 wells has demonstrated reliable performance, with consistent pressure isolation confirmed for upwards of a month and full dissolution within days in typical Delaware Basin fluids.

This method has been adopted as the standard well control approach for applicable gas lift operations, eliminating routine use of retrievable packers and snubbing, with the dissolvable packer applied in more than 50% of relevant completions and saving Devon Energy an estimated $250,000 per well in delayed production associated with downtime, for wells that would have traditionally forgone initial tubing install.

INTRODUCTION

Devon Energy operates approximately 3,800 wells in the Delaware Basin, with true vertical depths ranging from 9,000 to 13,000 ft in the core area and lateral lengths of 2 to 3 miles. Annual drilling activity includes approximately 250 horizontal wells, supported by an average of 13 drilling rigs and approximately 25 workover rigs. The artificial lift strategy for this area employs a hybrid gas lift design, with approximately 95% gas lift and 5% electrical submersible pumps for initial installations, selected based on gas-oil ratio, sour gas presence, and compression availability.

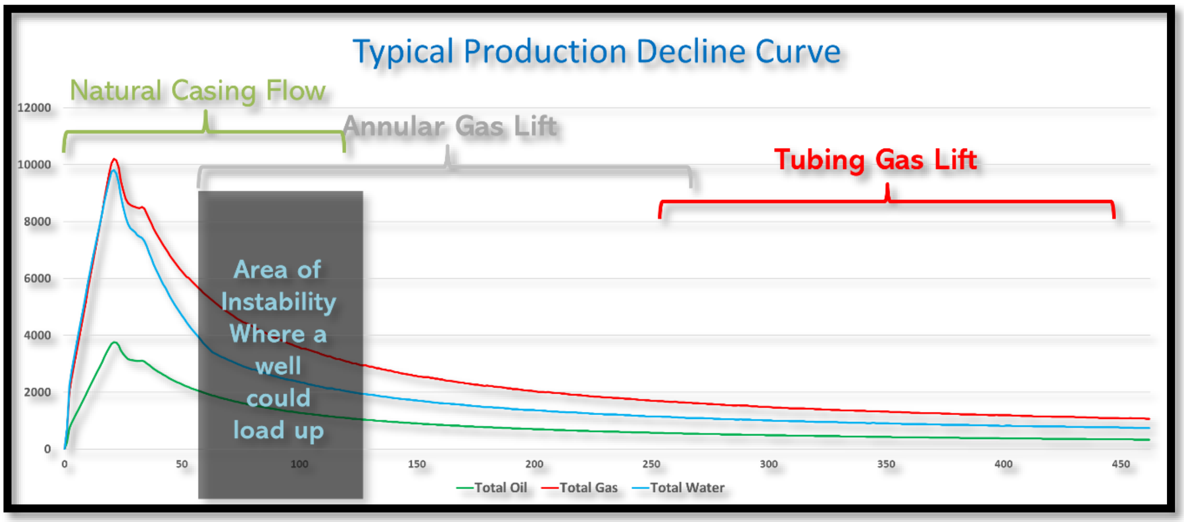

Figure 1: Typical production decline curve for Delaware wells

Wells in the Delaware are initially produced via natural casing flow before transitioning to annular gas lift (typically eight valves) and later tubing gas lift (approximately ten valves) as production rates decline. High bottomhole pressures in these wells require reliable well control during gas lift mandrel and tubing installation to ensure safe blowout preventer nipple-up and equipment deployment.

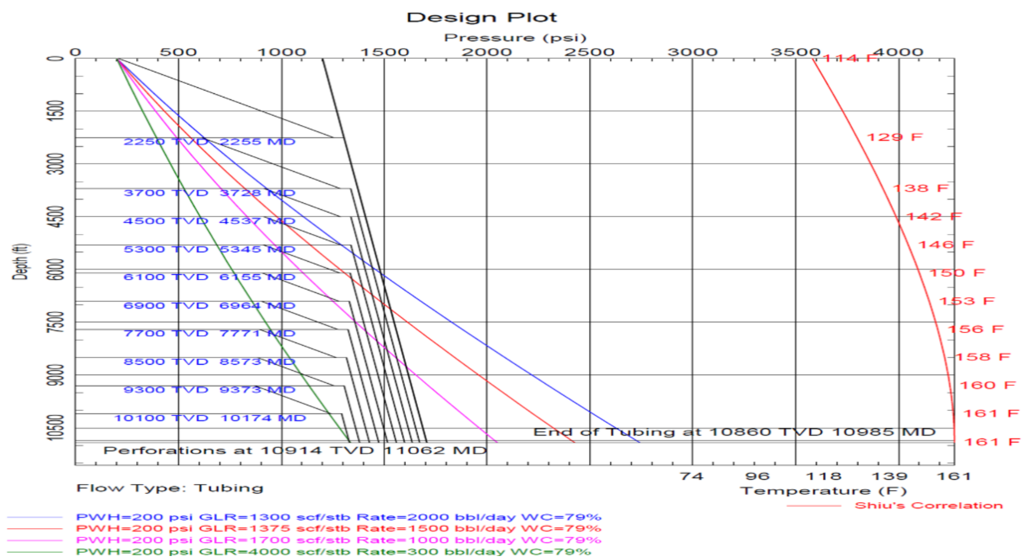

Figure 2: Typical Gas lift design for Delaware Operations

Running gas lift (GL) equipment into wells earlier in the life of the well is beneficial as an operator can gain more drawdown on their reservoir improving production. Additionally, if GL systems are in place during the natural casing flow period, the duration and stability of the natural flow period can be extended and enhanced. It is in this natural flow period of a wells life cycle where a well will often load up due to a multitude of unplanned reasons (for example a Frac hit from an offset stimulation treatment or surface takeaway issues) which would then require a costly intervention and subsequent installation of GL equipment to return the well to production. Either of these scenarios will require some form of well control.

Conventional methods for well control include flowing the well to low pressure and killing with 10–11 ppg brine which is used in approximately 70% of operations. Alternatively, setting mechanical packers (e.g., AS1 X type) with a pump-out plug has been used in approximately 20% of operations. Lastly, snubbing units have also been utilized in approximately 10% of operations to run tubing and gas lift systems under live pressure. All of these methods presented drawbacks including decreased well performance, intervention costs and non-productive time for packer retrieval, restricted wellbore access, and elevated health, safety, and environmental risks with snubbing.

This paper describes utilizing a new strategy for artificial lift deployment. By applying a dissolvable packer for temporary pressure isolation, operators can deploy the Gas Lift equipment on day one, directly after well cleanout operations and before natural flow enabling longer and more reliable natural flowing periods in their wells. Using this hybrid gas lift design, Operators are able to flow naturally up both the tubing and annulus till pressures require switching. This paper presents field results from more than

125 dissolvable packer installations enabling the earlier and deeper installation of gas lift systems.

Traditional Well Control Methods and Limitations

Well control during annular gas lift installations must maintain pressure control while running completion and artificial lift equipment. The primary options evaluated and used in traditional operations include:

1. Flow and kill with brine
   In this scenario, the well is flowed to approximately 300 psi surface pressure, then killed with 10–11 ppg brine. Gas lift equipment is run while maintaining hydrostatic balance.

   Benefits of utilizing this methodology include no downhole restrictions and peak initial production rates through casing.

   Limitations include higher brine costs, potential for formation damage, pressure balancing difficulties, risk of loading up due to takeaway constraints, extended downtime from rig scheduling, and the potential requirement for multiple wellsite visits.

2. Mechanical packer (e.g., AS1 X) with pump-out plug
   A retrievable packer rated to 10,000 psi from below is set with a pump-out plug for isolation.

   Benefits include reliable pressure handling with limited kill fluid use.

   Limitations include high cost of downhole components, potential for erosion, corrosion, sand accumulation, or scaling at the restriction; restricted future access for coiled tubing cleanouts or ESP setting; and requirement for a retrieval trip, which may involve fishing if complications arise. Setting depth is limited by retrieval feasibility.

3. Snubbing gas lift system post well cleanout and plug drill out.
   A snubbing unit controls pressure and maintains well control while running the gas lift assembly.

   Benefits include no permanent downhole restrictions.

   Limitations include high equipment and personnel costs, complexity in achieving optimal hybrid gas lift valve spacing, reduced tubing flow area with injection mandrel valves, and pressure balancing risks.

An evaluation of all these methods contributed to elevated non-productive time, costs, and operational complexity in high-pressure environments.

Dissolvable Packer Technology

The Dissolvable Packer is a temporary isolation tool constructed primarily of magnesium alloy components with hybrid sealing elements. Key specifications include:

- Casing compatibility: 4.5 in (11.6–13.5 lb/ft), 5.5 in (17–20 lb/ft), 6 in (22.3–24.5 lb/ft), 7 in (26–32 lb/ft)
- Pressure rating from below: Up to 8,000 psi (e.g., in 4.5 in casing)
- Temperature rating: Up to 275°F
- Integral pump-out plug: Adjustable shear values (up to 6 shear screws), expends to enable immediate flow through packer bore (post-expenditure ID approximately 1.5–2.22 in depending on casing size)
- Setting methods: Wireline or hydraulic with standard tools
- Dissolution: Controlled reaction with wellbore fluids, accelerated by chlorides; designed for at least 72-hour pressure seal, with full dissolution typically within approximately 14 days in Delaware Basin production fluids

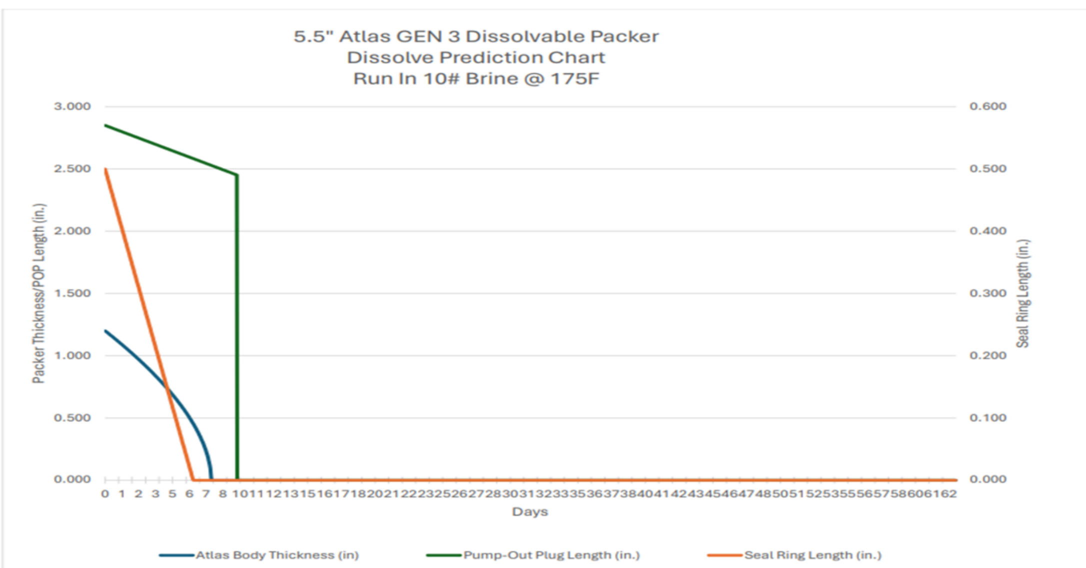

Figure 3: Dissolution chart for the Dissolvable Packer illustrates the life cycle and seal integrity for the major components of the packer.

The tool is set during gas lift assembly deployment, providing bi-directional pressure isolation for safe operations. The tool has an integrated dissolvable pump-out plug which once activated terminates well control and allows for fluid flow from the reservoir which initiates packer dissolution. Post-dissolution, only minor non-obstructive elements (buttons and seal remnants) remain, restoring full bore access without intervention. The compact design supports setting in high inclinations, including 90° sections.

Pilot Trials and Implementation Methodology

Our technology implementation trial occurred in **4 phases**.

In **Phase 1,** we leveraged a well candidate where the packer technology was utilized in a low risk operation. The goal in this phase was to pilot the technology, prove that the packer could hold at least 1000 psi differential pressure for more than 3 days and then dissolve, leaving no restriction in the wellbore. The dissolvable packer was placed into a pilot well where gauges had been installed and the pressure across the packer was measured and performance was confirmed as demonstrated in Figure 4.

Figure 4: Pressure gauge data showing that the packer was able to hold ~1000 psi DP for multiple days. Plot shows BHP and temperature before and after the activation of the pump out plug.

In **Phase 2,** we focused on implementing the dissolvable packer in traditional Gas Lift installations and continued with iterative testing. An additional 10 wells were identified for low-risk testing. In this phase, the dissolvable packer was set in the vertical portion of wells providing well control allowing the GL systems to be run above the packer. Additional downhole gauges demonstrated adequate pressure isolation and eventual intervention work, confirmed the dissolution of the packers and full wellbore access below them.

In **Phase 3,** we expanded the operating envelope where the packer technology was applied to improve well performance. An additional 20 wells were selected and packers were set earlier in the flowback life of the well, requiring the packers to hold more differential pressure (exceeding 4000psi) than earlier installs. In this phase, the dissolvable packer provided well control while the GL systems were deployed in vertical sections of the well completion. The ability to run the GL system earlier in the flow cycle of the well enhanced well performance and mitigated some of the risks associated with an unplanned well load up event.

In **Phase 4,** we expanded the operating envelope where the packer technology was applied to include setting of the packer in the deviated sections of the wellbore. In this phase, the dissolvable packer provided well control while the GL systems were deployed to deeper depths. The ability to run the GL system deeper into these wells enhanced well performance.

Deployment expanded to more than 125 successful installations across Devon Energy's Delaware Basin assets. The tool became the primary barrier for well control during blowout preventer nipple-up in applicable high-pressure gas lift operations.

Best practices included:

- Flushing wells with fresh water during well drill out/cleanout operations to reduce risk of premature dissolution of the packer
- Maintaining backup packer, weighted brine, and 15% HCl on standby in case of operational issues
- Ensuring at least 100 ft spacing between packers in cases where multiple packers wight be utilized to prevent pump-out plug interference and lodging into the lower packer.
- Settled on the non-dissolving rubber sealing elements for Delaware operations.

Installations typically occurred post-cleanout, often with workover equipment on location for day-one readiness. The majority were set at inclinations of 45° or greater. Pressure differentials were monitored, with tagging attempts post-flow to confirm dissolution.

FIELD RESULTS AND PERFORMANCE

In these extended field trials, pressure isolation performance has been consistent and dissolution has occurred predictably, with full dissolution confirmed via tagging in typical production fluids within days to approximately 14 days. No premature failures were reported across more than 125 runs. Adoption has progressed to become a standard practice for applicable wells, with dissolvable packers used in over 50% of relevant completions. Routine application of brine kill fluids, retrievable mechanical packers, and snubbing was eliminated.

- **Number of installations:** More than 125 wells
- **Average pressure packer held:** 1,500 psi differential pressure (DP) for 85 hours
- **Maximum pressure packer held:** Exceeded 4,500 psi DP held for 240 hours.
- **Maximum time packer held:** Exceeded 2,500 psi DP held for 600 hours.
- **Deviation of well at packer depth:** Majority of packers have been set between 45 and 60 deg.
- **Average isolation duration:** Up to one month, with typical seal lasting at least 72 hours
- **Full dissolution time:** Confirmed within days to approximately 14 days in Delaware Basin fluids
- **Financial Impact:** By enabling stable flow prior to GL activation, likely well load up events were eliminated or mitigated in 40% of the target wells. This saved Devon on average a week of downtime on a key group of high production rate wells, which has delivered Devon a $250,000 per well savings from delayed production.

Quantitative field data demonstrates the reliability, predictability, and operational value of dissolvable packers for well control.

CONCLUSIONS

Dissolvable packers have become the standard well control method for applicable Delaware Basin operations, applied in more than 50% of relevant completions. Continued use supports operational efficiency and production optimization, reducing intervention needs, costs, and NPT. The technology offers a safer, more reliable, and accessible solution for high-pressure gas lift installations.

The dissolvable packer is a proven, intervention-free well control solution, offering significant performance and operational advantages for oilfield professionals.

With field deployment of more than 125 Dissolvable Packers, we have demonstrated reliable pressure isolation and predictable dissolution in high-pressure Delaware Basin gas lift installations. The tool enabled day-one gas lift readiness, eliminated routine use of kill fluids, retrievable packers, and snubbing, and reduced associated non-productive time, costs, and risks.

ACKNOWLEDGMENTS

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