

# HIGH PRESSURE GAS LIFT UPPER COMPLETION DESIGN STRATEGY

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## **ABSTRACT**

This paper explores the High Pressure Gas Lift (HPGL) upper completion design strategy, focusing on optimizing gas lift design for a life-of-well approach that ensures optimal economics. High Pressure Gas Lift is a relatively new concept in the gas lift space, utilizing compressor discharge pressures up to 4,000 psi to enable single-point injection at depths unachievable with conventional low-pressure compression. While HPGL unlocks maximum drawdown and higher initial production rates through annular flow, the upper completion design must account for the full well lifecycle – from initial annular flow through eventual tubing flow and compressor release. A comparative analysis of six upper completion design options – Slick Tubing, Single Point with Conventional Gas Lift Valves (GLV), Side-Pocket Mandrels (SPM) for tubing flow, Hybrid SPM, High Pressure GLV, and Conventional GLV with check valves or burst discs – was conducted using field data from over 100 HPGL installations across the Delaware Basin. Economic modeling across annular flow periods of 18, 24, and 30 months reveals that day-one SPM installations with dummy valves significant OPEX savings per well compared to slick tubing designs while eliminating the need for a workover to transition from high-pressure to low-pressure compression. Operational trial data, including annular-to-tubing flow conversions and HPGL-to-conventional gas lift transitions, quantify the production impacts of these design changes. Pull findings from eight completed tubing pulls identify collar erosion as a consistent integrity concern in annular flow environments. The result is a decision framework that matches upper completion design to expected annular flow duration and compressor release strategy, balancing cost, reliability, and operational flexibility across the life of the well.

## **INTRODUCTION**

High Pressure Gas Lift represents the latest advancement in gas lift technology for unconventional wells. Traditional low-pressure gas lift compressors output approximately 1,200 psi, which limits injection depth and drawdown capability. HPGL compressors, by contrast, deliver discharge pressures up to 4,000 psi, enabling single-point injection at significantly greater depths. This deeper injection point creates what is effectively a “maximum drawdown mode” for gas lift, allowing operators to maximize early-life production rates.

In the Permian Basin Delaware operations, HPGL is applied primarily to 5.5 inch, 20# casing wells with 2-7/8 inch tubing. Wells are produced on annular flow during the high-rate early life period to maximize production and meet initial target rates. As wells

decline and fluid rates drop below the critical velocity required to sustain annular flow, they must transition to tubing flow using gas lift valves – and eventually be released from high-pressure compression to lower-cost alternatives.

The challenge is not the HPGL concept itself, but the upper completion design required to support the full well lifecycle. A slick tubing completion is the simplest day-one installation, but it provides no mechanism to transition from annular to tubing flow without a workover. Installing gas lift valves on day one eliminates future workover costs but introduces reliability risk during the annular flow period, where high fluid velocities and sand production can damage valves. Side-pocket mandrels with dummy valves offer a middle path: the mandrels are installed with the completion, and live valves are deployed via wireline when needed – but this adds mandrel cost and wireline complexity.

To date, over a hundred high-pressure gas lift wells have been installed across the Permian operations. This growing operational dataset, combined with economic modeling and pull findings, provides the basis for a data-driven upper completion design strategy. This paper presents comparative analysis, operational trial results, and failure observations that inform the recommended approach.

## **METHODOLOGY**

### ***Upper Completion Design Options***

Six upper completion configurations were evaluated for HPGL wells. Each represents a different approach to managing the annular-to-tubing flow transition and compressor release timing:

- 1. Slick Tubing (Annular Flow Only):** The simplest day-one installation with no gas lift equipment. Wells produce on annular flow using HP compression. To transition to tubing flow or release the HP compressor, a full workover is required to install gas lift valves if kickoff pressure requirements are higher than available discharge pressures. This design does not provide flexibility to single-stage or release HP compressors without intervention.
- 2. Single Point with Conventional GLV:** Gas lift valves are installed on day one as part of the completion. This eliminates future workover costs and enables direct transition to tubing flow. However, the valves are exposed to the full annular flow environment from day one, creating risk of erosion or damage from sand and high-velocity fluids.
- 3. Side-Pocket Mandrels:** SPMs are installed on day one with dummy valves. Live gas lift valves are deployed via wireline when the well is ready to transition from high pressure to conventional gas lift.
- 4. Hybrid SPM Design:** An optimized design combining annular flow mandrels (EC mandrels to approximately 7,000 ft TVD) and tubing flow mandrels to end of tubing, totaling 10–11 mandrels per well. Dummy valves are installed on day one. This design accommodates both extended annular flow periods and eventual tubing flow conversion, providing the most operational flexibility.

5. High Pressure GLV with Medium Pressure Discharge: Conventional high-pressure gas lift valves designed for annular flow operation. Currently under technical review as a trial configuration.

6. Conventional GLV with Check Valve or Burst Disc: Traditional gas lift valve designs adapted for the HPGL environment with additional safeguards (10k check valve or burst disc) to mitigate valve integrity risk.

### ***Economic Analysis Framework***

Economic comparisons were conducted using a cumulative cost analysis over a 48-month period. The primary cost components include day-one completion costs (mandrels, dummy valves, tubing modifications), wireline intervention costs for valve installation, workover costs for tubing pulls and GLV installations, monthly HP compression costs, and monthly LP compression costs post-transition.

Each design was modeled across three annular flow duration scenarios: 18 months, 24 months, and 30 months. These durations reflect the range observed in the field, driven by well productivity, decline rates, and critical rate thresholds for sustained annular flow. The cost analysis compares six configurations: Single Point (no valves), Single Point with Annular SPM, Single Point with Tubular SPM, Single Point with Conventional GLV, Single Point with Hybrid GLV, and Single Point with Hybrid SPM.

Shared compression economics were also considered. The facility design utilizes a shared gas lift header system with both HP (4,000 psi) and LP (approximately 1,200–1,300 psi) gas headers. This infrastructure allows wells to be swapped between high-pressure and low-pressure service, and shared compression costs across multiple wells have significantly lowered per-well expenses compared to a one-to-one well-to-compressor arrangement.

### ***Operational Trials***

Field trials were conducted to quantify the production impact of key operational transitions: annular flow to tubing flow conversions under HPGL compression, HPGL annular flow to conventional gas lift (both annular and tubing flow), and electric gas lift (EGL) installations as an alternative lift method. Trial data were analyzed using pre- and post-conversion production rates for oil, gas, and water to determine the magnitude of production changes associated with each transition.

### ***Pull Analysis***

Sixteen HPGL pulls were analyzed to identify common failure modes and integrity concerns. Pulls were categorized by driver: proactive (scheduled), plugged tubing, or hole-in-tubing (HIT). Tubing scans and physical inspections documented the condition of tubing bodies, collars, and downhole equipment.

## **RESULTS AND DISCUSSION**

### ***Section 1: Economic Analysis – 18-Month Annular Flow Period***

For wells with an expected annular flow period of 18 months, the tubing flow SPM design is the preferred configuration. The cumulative cost analysis over 48 months shows clear separation between designs.

Single Point configuration (slick tubing requiring a workover to install GLVs) accumulates approximately \$2.9 in total OPEX over 48 months. The Single Point with Tubular SPM design reaches approximately \$1.08 X – a savings of approximately \$1.8 X per well compared to slick tubing and approximately \$1.4 X in OPEX savings compared to a conventional GLV workover approach.

Single Point with Conventional GLV design costs approximately \$1.89 X, while the Single Point with Annular SPM reaches approximately \$2 X. The Hybrid SPM and Hybrid GLV configurations fall between these values.

The economic advantage coupled with reliability risks of the tubular SPM design in the 18-month scenario stems from avoiding both the workover cost and the extended HP compression costs associated with slick tubing. By installing SPMs on day one, the wireline-deployed valve installation at month 18 is significantly less expensive than a full workover, and the well can transition to LP compression without requiring rig mobilization.

Options - HPGL Upper Completion (Day One Install)	Workover Timing	GLV Install Cost	Wireline Required	HP Compressor Removal	Total Cost* (48 Months)	Risk of GLV Leak
<b>Slick TBG</b> (Single Point)	18 Months	\$0 Y	No	18 Months	\$2.90 X	Zero
<b>SPM</b> (Hybrid)	48 Months	\$4.5 Y	Yes	12 Months	\$1.89 X	Low
<b>SPM</b> (TBG Flow)	48 Months	\$3.5 Y	Yes	18 Months	\$2 X	Low
<b>Conv. GLV</b> (TBG Flow)	48 Months	\$1 Y	No	18 Months	\$1.5 X	Medium
<b>Hybrid Conv. GLV</b> (Annular + TBG Flow)	48 Months	\$1.5 Y	No	12 Months	\$1.08 X	High

*Figure 1 – Cumulative cost analysis for upper completion designs with 18-month annular flow period*

## **Section 2: Compressor Optimization and Release Strategy**

The upper completion design needs to be considered in tandem with the compressor release strategy. Several factors govern when and how HP compressors can be released:

- Discharge pressure requirements for well kickoff after shutdown events dictate the minimum available compression pressure. During stable production, the

required discharge pressure may be lower, but the system must be designed for the worst case.

- Injection pressure and gas availability on the shared header system mean that every well on the pad matters – one high-demand well can constrain compression availability for the entire pad.
- Production decline rates and the critical rate threshold for annular flow determine when a well naturally transitions to tubing flow. Wells with higher initial rates or slower decline curves maintain annular flow longer, extending the period of HP compression dependency.

The Hybrid SPM design directly addresses compressor release by allowing continued annular flow without HP compression. The annular flow mandrels enable wells with prolonged annular flow periods to be switched to LP compression and single-staged, freeing HP compression capacity for other wells on the pad. Similarly, the tubing flow SPM design allows for rigless conversion from annular to tubing flow, enabling more depleted wells on a pad to be converted to LP or central compression sooner, lowering HP injection gas demand.

### **Section 3: Operational Trial Results**

Annular flow to tubing flow conversion trials were conducted across multiple wells with fluid rates ranging from 1,450 to 1,850 bfpd. These conversions yielded production haircuts averaging approximately 17–20%, with the average reduction being 20%. This production loss is an expected consequence of transitioning from annular to tubing flow and must be factored into the economic analysis when determining optimal conversion timing.

HPGL to conventional gas lift conversions provided additional data points. Table 1 summarizes the key trial results.

<b>Well</b>	<b>Configuration</b>	<b>Oil (bopd)</b>	<b>Gas (mcf/d)</b>	<b>Water (bwpd)</b>
Well A	Annular Flow HPGL	179	1,075	1,720
Well A	Annular Flow EGL	97	297	608
Well A	Tubing Flow EGL	113	582	798
Well B	Annular Flow HPGL	177	1,498	1,380
Well B	Annular Flow Conv. GLV	168	1,340	1,340

*Table 1 – Operational trial results: HPGL to conventional conversion*

Well B annular flow HPGL to conventional annular flow conversion showed a modest approximately 5% production haircut, indicating that the transition from HP to LP

compression in annular flow mode preserves most of the production. In contrast, Well A conversions from HPGL annular flow to conventional tubing flow resulted in 17–20% haircuts, consistent with the annular-to-tubing conversion trials.

Well A electric gas lift trial showed a more significant production reduction when transitioning from HPGL to EGL, though this well also experienced a change in flow regime from annular to tubing. Two electric gas lift installations were completed and the EGL trial data have been applied to inform both HPGL and conventional designs.

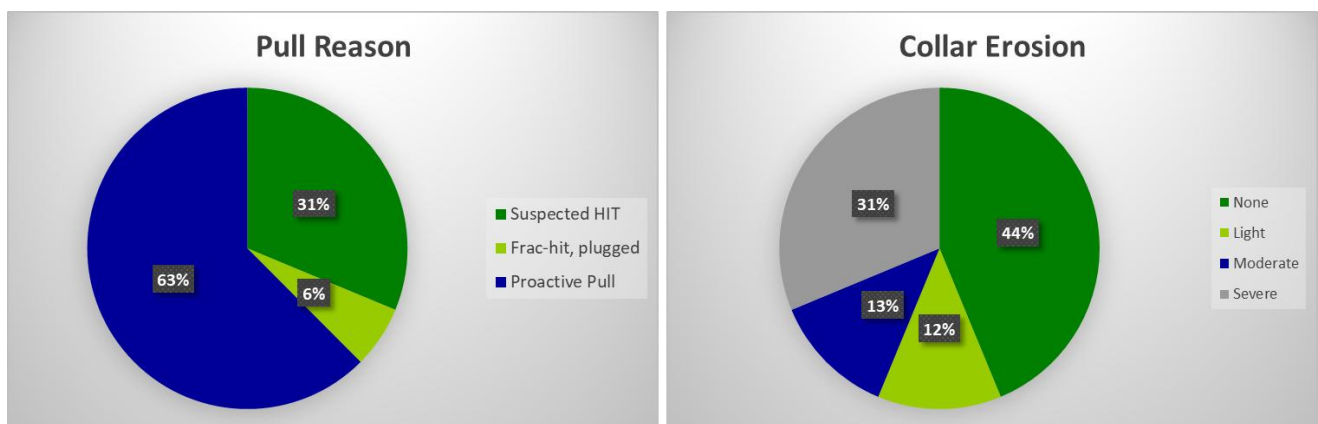
### **Section 6: Significant Learnings from EGL and Gas Lift Optimization**

The electric gas lift trials provided insights beyond the EGL technology itself. EGL data brought a different perspective on the gas lift unloading process and true valve requirements. This was a major driver in optimizing the standard side-pocket mandrel hybrid design for day-one completions on new wells. Analysis of the EGL unloading data showed that fewer valves were needed than traditional designs specified, leading to the elimination of 4 side-pocket mandrels per new well.

These learnings also supported a more aggressive approach to conventional gas lift design optimization, resulting in wells running fewer valves, achieving deeper injection points, and realizing improved reliability. The convergence of HPGL, EGL, and conventional gas lift operational data has created a feedback loop that improves design across all lift methods.

### **Section 7: Tubing Pull Findings**

Eight tubing pulls from HPGL wells have been completed, providing critical data on downhole conditions in the annular flow environment. The pulls were driven by three categories: proactive inspections (63%), plugged tubing (6%), and hole-in-tubing failures (31%).



*Figure 2 – HPGL tubing pull drivers by category*

### **Collar Erosion**

Collar erosion is the most consistent finding across the pull program and is a common observation among other operators utilizing annular flow gas lift. The erosion mechanism is driven by high fluid velocity and sand flowing past the tubing in the

annular space. At tubing collar upsets, localized flow disturbance creates erosional wear patterns that reduce collar wall thickness over time.

Tubing scans from the pulled wells yielded mostly yield-body (YB) grade tubing apart from a few wells with corrosion failures, where more severe degradation was observed. Several mitigation solutions are currently under technical review:

- Nickel-plated and heat-treated collars
- Special clearance collars to reduce annular velocity at collar upsets
- Boronized collars
- Protective coatings applied to collar OD surfaces

### ***Tubing Body Corrosion and Erosion***

On a few wells, hole-in-tubing failures driven by tubing body corrosion and erosion were observed. These failures are currently under root cause failure analysis (RCFA) investigation. The distinction between corrosion-driven and erosion-driven failure mechanisms will determine the appropriate mitigation strategy. Solutions under technical review include coated tubing (internal and/or external), continuous coiled tubing chemical treatment versus batch treatment, and alternative metallurgy for corrosive environments.

A positive finding from the pull program is that wireline-set packers have been successfully retrieved across the pulls conducted, confirming that the completion design allows for equipment recovery without full tubing pull in appropriate circumstances.

### ***Section 8: Third Bone Spring Gas Lift Design Strategy***

An adjacent application of the gas lift optimization framework was demonstrated on a Third Bone Spring (3BSH) well. Well C was experiencing high water influx that exceeded the capacity of the original 2-7/8 inch tubing configuration.

By downsizing from 2-7/8 inch to 2-3/8 inch tubing, total fluid volume increased from approximately 5,300 bfpd to approximately 6,700 bfpd, and oil production doubled from approximately 100 bopd to approximately 212 bopd. The smaller tubing increased fluid velocity, improving lift efficiency in the high-water-cut environment. This approach of utilizing 2-3/8 inch tubing is now being considered for 3BSH wells with increased risk of higher water influx, demonstrating how the gas lift design strategy extends beyond HPGL to the broader artificial lift portfolio.

## **LIFE OF WELL ARTIFICIAL LIFT STRATEGY**

The HPGL upper completion design fits within a broader life-of-well artificial lift framework that spans three phases:

**Early Life – Gas Lift (HPGL):** Wells are completed with the SPM or Hybrid SPM string from day one using the completion rig. During the early high-rate period, wells produce on annular flow with HP compression at maximum drawdown. The goal during this phase is to maximize production while the reservoir energy supports high fluid rates.

Mid Life – Gas Lift (Conventional): As wells decline below the optimum rate for annular flow (approximately 1,200 bfpd), they are converted to tubing flow using wireline-deployed gas lift valves in the pre-installed SPMs. HP compressors are released and wells transition to LP compression or central facility compression.

Late Life – PAGL: When wells decline to below 300 bfpd, they are considered to be converted to PAGL. This helps with improving gas lift efficiency.

The overarching objective is a “zero-touch” completion philosophy: run tubing flow SPM or hybrid SPM string from day one with the completion rig and eliminate workovers until tubing failure. Every workover avoided is both cost savings and an HSE risk reduction.

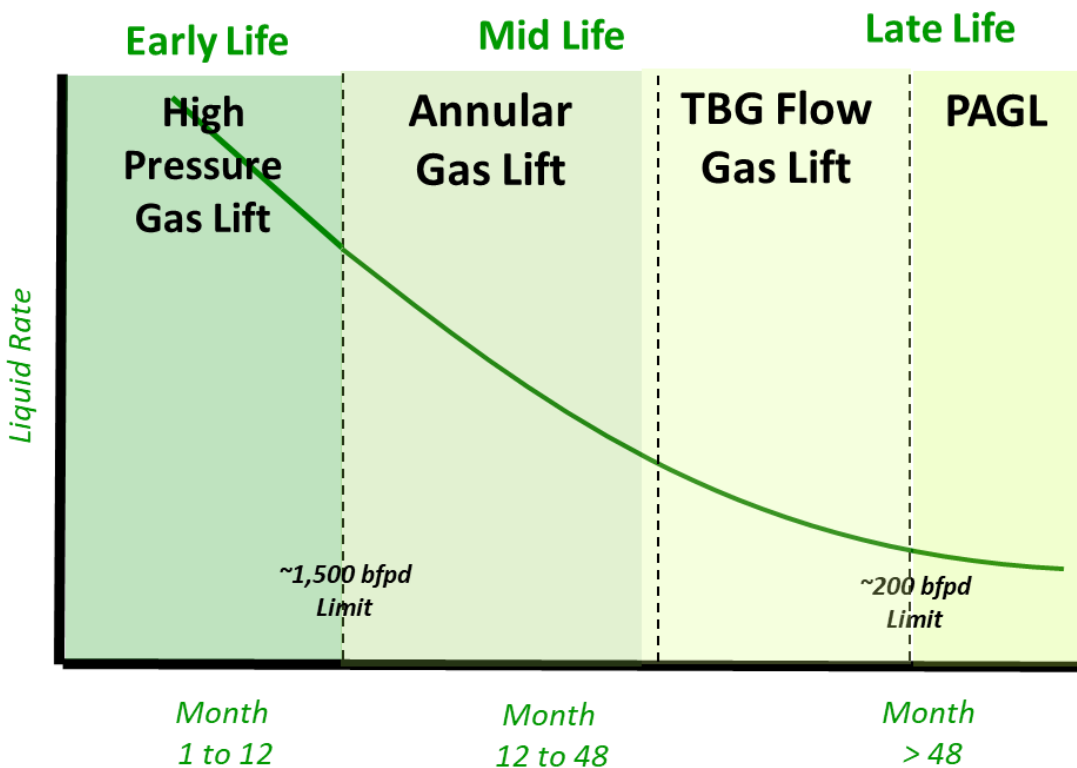


Figure 3 – Well Lifecycle

## CONCLUSIONS

1. Day-one SPM installation with dummy valves is the recommended upper completion design for HPGL wells. This approach eliminates the need for a workover to switch from HP to LP compression, provides the business with flexibility on removing and single-staging HP compressors, and reduces LOE by approximately \$1.0 X per well.
2. The optimal SPM configuration depends on expected annular flow duration. For wells with approximately 18-month annular flow periods, the tubing flow SPM design is most economical. For wells with annular flow periods exceeding 18 months, the

Hybrid or Annular flow SPM design provides superior economics by enabling HP compressor release during the annular flow phase.

**3.** Slick tubing is the most expensive long-term option. Despite the lowest day-one completion cost, the cumulative cost of extended HP compression and eventual workover makes slick tubing the least economical design across all annular flow duration scenarios analyzed.

**4.** Annular-to-tubing flow conversion results in approximately 17–20% production haircuts when done prematurely. This production loss must be factored into the transition timing decision, balanced against compression cost savings and compressor release benefits for the broader pad.

**5.** HPGL-to-conventional annular flow conversion preserves most production. The approximately 5% haircut observed on the Well B conversion indicates that transitioning from HP to LP compression while maintaining annular flow is a viable strategy for wells that can sustain annular flow at lower injection pressures.

**6.** Tubing collar erosion is a consistent integrity concern in annular flow environments. Multiple mitigation solutions are under technical review, and this represents the primary reliability risk for HPGL completions operating in annular flow for extended periods.

**7.** Shared compression infrastructure significantly improves HPGL economics. The shared HP/LP gas lift header system enables well-level flexibility in compression assignment, and per-well compression costs are substantially lower than a one-to-one well-to-compressor arrangement.

**8.** Cross-pollination between lift methods improves all designs. EGL trial data directly informed HPGL mandrel optimization, eliminating 4 SPMs per well and supporting more aggressive conventional gas lift designs with fewer valves, deeper injection, and improved reliability.

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