# 3-1/2" TUBING PAGL APPLICATION: AN ALTERNATIVE TO TUBING REPLACEMENT

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## Abstract

This study evaluates a 3-1/2 in. tubing well converted from continuous gas lift to plunger-assisted gas lift (PAGL) using a bypass plunger that initially failed to complete cycles under flowing conditions. The objective is to diagnose the root cause, determine operational boundaries for PAGL in 3-1/2 in. tubing, and assess the feasibility of PAGL relative to tubing replacement and higher gas-injection strategies using field data and plunger lift mechanistic models.

Steady-state multiphase flow simulations and drag-based mechanistic models were used to estimate plunger fall and upstroke velocities along the well, cycle durations, and kinetic energy at impact. Model results indicated that a 14-in. bypass plunger should be able to fall against flow rates exceeding 2 mmscf/d for this well. However, field data showed that the custom 3-1/2 in. tubing plunger had an undersized inner orifice, making it too restrictive to fall against flow. Consequently, prolonged shut-in times were required, which increased bottomhole pressure and reduced production. After deploying a proportionally designed bypass plunger with a larger inner orifice, PAGL operation stabilized with a 2-minute shut-in and production increased.

This paper presents a comparative study demonstrating that continuous-flow plunger deployment in larger tubing can provide a cost-effective alternative to tubing replacement, enabling operators to reduce gas injection while avoiding liquid loading.

## Introduction

The production lifetime of unconventional wells typically begins with high initial gas and liquid flow rates. As reservoir pressure is depleted through continued hydrocarbon extraction, these production rates naturally decline. This decline in gas production leads to a corresponding reduction in the gas velocity profile throughout the production tubing. When the gas velocity falls below the critical threshold required to suspend liquid droplets, a phenomenon known as liquid loading occurs. A liquid-loaded section in the tubing creates backpressure, further reduces production, and eventually leads to erratic production.

For continuous production, avoiding or postponing liquid loading is possible with three methods: gas lift, surface compression, and tubing size reduction. Increasing total gas flow rate with gas lift helps to increase the gas velocity profile. Utilizing surface compression to lower the wellhead pressure reduces the pressure profile along the well, expanding the gas and increasing gas velocity along the well. Utilizing a velocity string, or replacing tubing, effectively reduces the flow area and increases gas velocity. Using these methods typically increases the gas velocity for a given net gas production flow rate, thus helping to avoid liquid loading.

The plunger lift method allows the well to operate under liquid loading conditions as it unloads the well with each plunger cycle, thereby reducing the negative effects of liquid loading. Continuous flow plunger lift operation uses little to no shut-in time and typically uses plungers (two-piece, bypass, dart) that can fall against flow. Conventional plunger lift is operated as intermittent production, and it is used later in the life of the well when there is not enough gas flow rate to operate the well continuously. If a well utilizes both plunger lift and gas lift, and it is operated with prolonged shut-in time (typically more than 15 minutes) to build pressure in the casing, then this is intermittent production and is denoted as gas-assisted plunger lift (GAPL). Plunger-Assisted Gas Lift (PAGL) definition is used for continuous flow plunger lift applications with gas lift. The main characteristics of PAGL are related to the production valve opening sequence. PAGL applications are operated with short shut-in times to allow the plunger to be released from the lubricator.

Tubing size design decisions consider different parts of the production life cycle of the well. Larger tubing reduces frictional pressure losses and therefore provides higher production rates in the early life of the well, but it also experiences higher gravitational pressure losses and liquid loading issues as production rates decline. Replacing tubing for a smaller one to avoid liquid loading is not always feasible.

Continuous gas lift requires higher injection rates to avoid liquid loading compared to the gas injection requirements of PAGL applications. Instead of tubing replacement, gas lift to PAGL conversion has been shown to be beneficial in many studies for reducing gas injection rates and increasing production (Burns, 2015). However, this application has not been reported for 3-1/2 in. tubing with continuous flow plunger lift.

Gerrard and Hearn (2003) discussed a 3-1/2 in. conventional plunger lift application in the Green River Basin. In this study, they successfully utilized brush plungers in up to 40 wells. Up to two days of shut-in time and maximum liquid production of 70 STB/d with varying gas production flow rates were reported. Casing plunger applications were found to be successful and cheaper to install than 2-1/16 in. tubing and 1-1/4 in. coiled tubing.

## 3-1/2 in Tubing Replacement or PAGL Conversion

Well #1 was completed with 3-1/2 in. production tubing and operated with continuous gas injection. The well was producing more than 4000 Mscf/d of gas and 4500 STB/d of liquid at approximately 80% water cut after five months. Gas injection was increased to as much as 1000 Mscf/d to avoid liquid loading. As gas production declined, the injection requirement continued to increase. To reduce compression demand, emissions, and gas-injection needs, a bypass plunger was deployed to convert the well to PAGL. **Figure 1** shows the moving-average trends of oil, gas, liquid, and gas-injection rates.

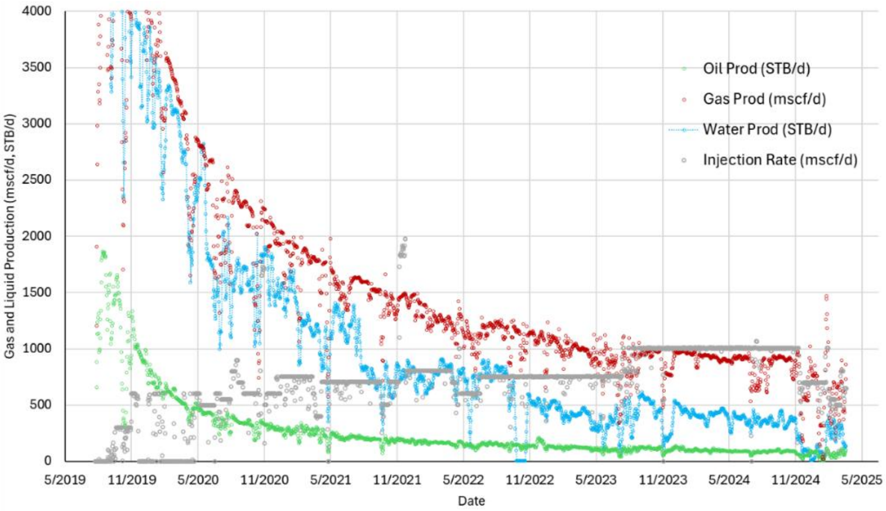


**Figure 1: Production History of Well #1**

A tubing change to 2-3/8 in. or 2-7/8 in. would improve gas velocity and reduce the gas injection needed to keep the well unloaded. However, that option would require a workover, added downtime, and higher cost. Converting the well to PAGL was therefore considered the more practical and cost-effective option.

For this pilot application, the vendor provided a custom 3-1/2 in. plunger-lift system, including the plunger, lubricator, and bottomhole assembly. The initial setup used a 14-in., five-slot bypass plunger. The first field deployment began on November 24. Early results showed inconsistent cycling, and additional downtime occurred because of equipment and gas-lift-related issues (Figure 2).

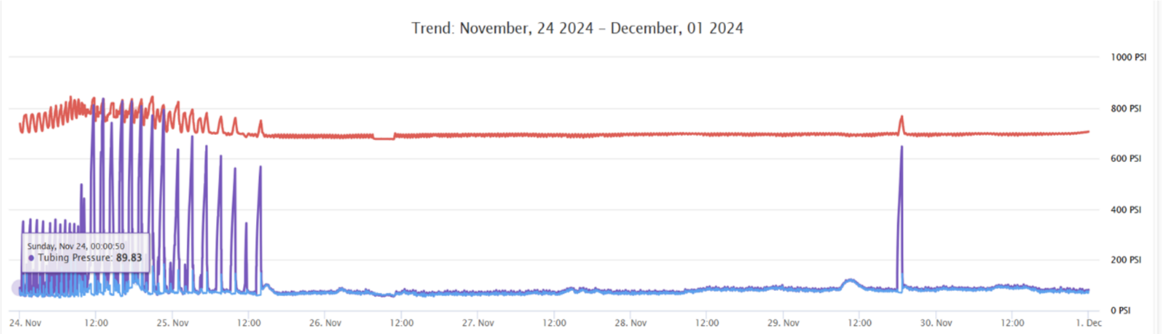


**Figure 2: Wellhead Pressure During the Initial Days of Bypass Plunger Deployment**

**Figure 3** shows the pressure measurements during the initial PAGL trials. Instead of cycling with the short shut-in times normally expected for continuous-flow plunger lift, the well required about 20 to 25 minutes of shut-in to complete cycles. This indicated that the application was not behaving as a PAGL system. Such prolonged shut-in moved the well away from continuous production and toward intermittent operation. For a well producing over 1000 mscf/d and liquid production of 500 STB/d, this is not ideal to minimize bottomhole pressure and maximize overall production. Average downhole pressure readings were also shown to follow an increasing trend over the next few days.

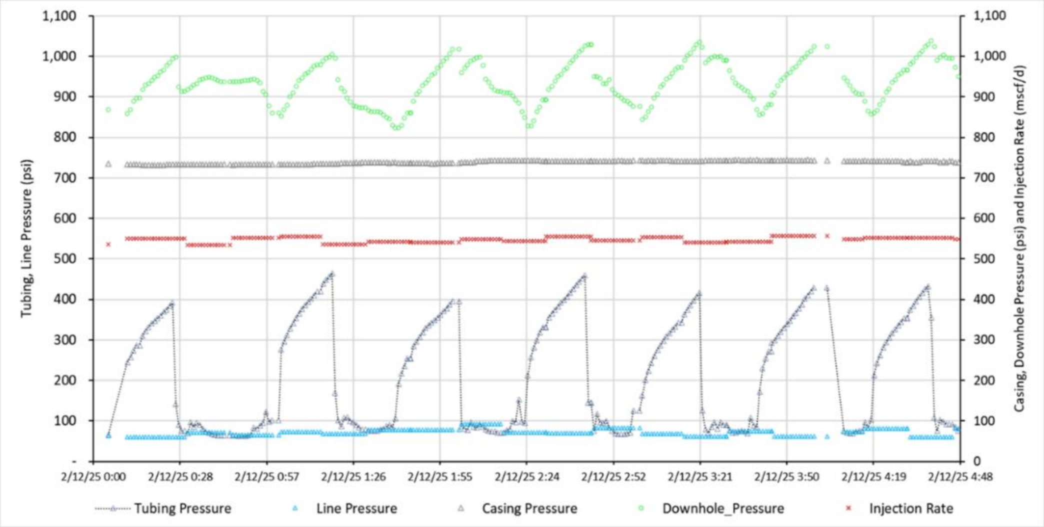


**Figure 3: Prolonged Shut-In Times During Initial PAGL Trials**

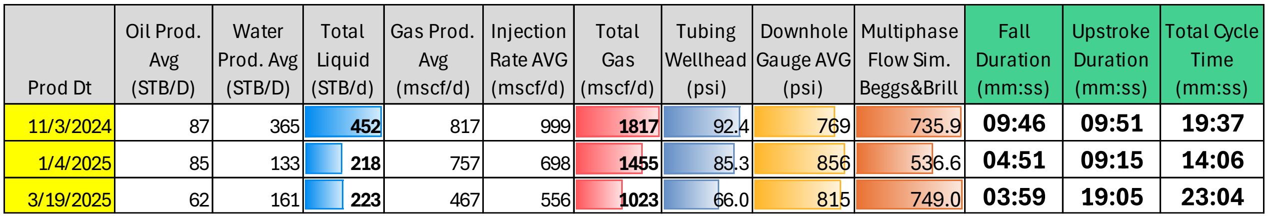
## Continuous Flow Plunger Lift Mechanistic Model

Rowlan et al. (2013) developed a plunger fall-velocity model using measured field data from plunger fall velocities. Their method used drag coefficient values back-calculated from measured velocities and applied a fall performance coefficient to predict plunger fall under different pressure and temperature conditions. That work was developed primarily for conventional plunger lift applications under shut-in conditions.

For continuous-flow plunger lift, Sayman et al. (2021) extended the drag-based approach to plungers falling under flowing multiphase conditions. The model incorporated wall effect, deviation, liquid holdup, and changing gas density along the wellbore, and used a drag coefficient versus Reynolds number relationship for different plunger geometries. By coupling the drag-based fall formulation with steady-state multiphase-flow simulation, the model can estimate fall velocity along the well, total fall duration, and the maximum flow rate a plunger can fall against. In this study, the mechanistic fall and upstroke models were used to evaluate whether the 14-in. bypass plunger should be able to cycle under the well conditions.

## PAGL Simulations

For the given well conditions, multiphase flow simulations were run with different pressure drop correlations and compared with downhole pressure gauge data. Beggs & Brill (1973) was found to be suitable for the given case. The plunger fall and upstroke mechanistic models were used to run PAGL simulations. Three representative operating points were selected from the field dataset and are summarized in **Table 1**. The simulations were performed for a 14-in., five-slot bypass plunger with a shut-in time of 2 min 15 sec. For all three cases, the model predicted that the plunger should be able to fall and upstroke under the prevailing well conditions. The cases covered total gas rates from 1023 to 1817 Mscf/d and liquid rates from 218 to 452 STB/d, with estimated total cycle times of about 14 to 23 minutes.



| Prod Dt | Oil Prod. Avg (STB/D) | Water Prod. Avg (STB/D) | Total Liquid (STB/d) | Gas Prod. Avg (mscf/d) | Injection Rate AVG (mscf/d) | Total Gas (mscf/d) | Tubing Wellhead (psi) | Downhole Gauge AVG (psi) | Multiphase Flow Sim. Beggs&Brill | Fall Duration (mm:ss) | Upstroke Duration (mm:ss) | Total Cycle Time (mm:ss) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11/3/2024 | 87 | 365 | **452** | 817 | 999 | **1817** | 92.4 | 769 | 735.9 | **09:46** | **09:51** | **19:37** |
| 1/4/2025 | 85 | 133 | **218** | 757 | 698 | **1455** | 85.3 | 856 | 536.6 | **04:51** | **09:15** | **14:06** |
| 3/19/2025 | 62 | 161 | **223** | 467 | 556 | **1023** | 66.0 | 815 | 749.0 | **03:59** | **19:05** | **23:04** |

**Table 1: Selected Production Rates Used for PAGL mechanistic model simulations**

These results indicated that the well conditions and plunger type should have been sufficient for PAGL operation with a short shut-in. Mechanistic models for PAGL were initially developed with experimental work in 2-3/8 in. tubing, and previous studies showed that they could successfully estimate fall and upstroke velocities. The investigation therefore shifted to the custom 3-1/2 in. plunger-lift equipment and possible design-related limitations.

## Plunger Type

The plunger vendor provided the plunger weight and a technical drawing for the bypass plunger used in this well (**Figure 4**). Based on that information, the plunger OD and inner-orifice dimensions were examined in more detail.

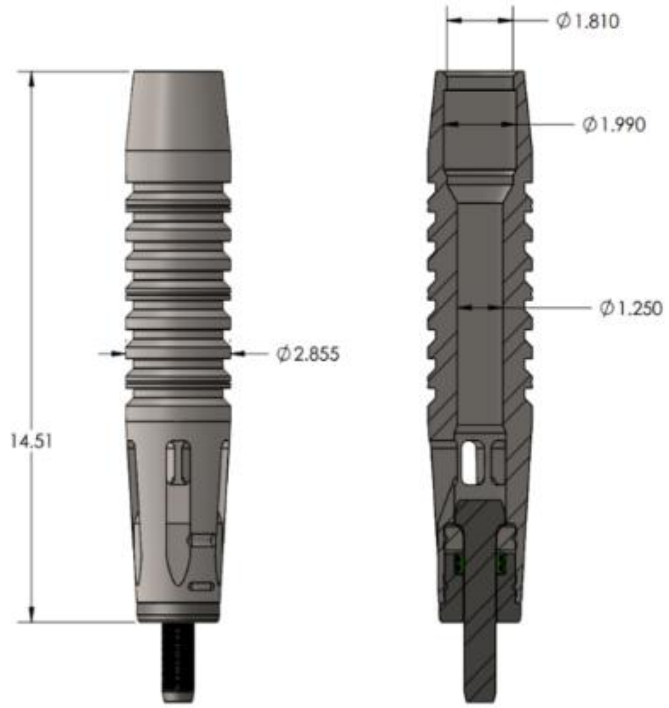


**Figure 4: Technical Drawing of 14-in Five-Slot Bypass Plunger.**

Plunger OD

Experimental work from the University of Tulsa on the fall velocity of conventional and continuous-flow plungers showed that the OD of continuous-flow plungers does not influence fall velocity significantly (Akhiiratdinov, 2020; Sayman et al., 2020).

**Figure 5** shows that bar-stock plungers with outer diameters of 1.7, 1.85, and 1.9 in. fall slower in a 2-in. acrylic tube as the annular clearance became smaller. This reflects the strong sensitivity of conventional plungers to plunger-to-tubing clearance during the fall stage.

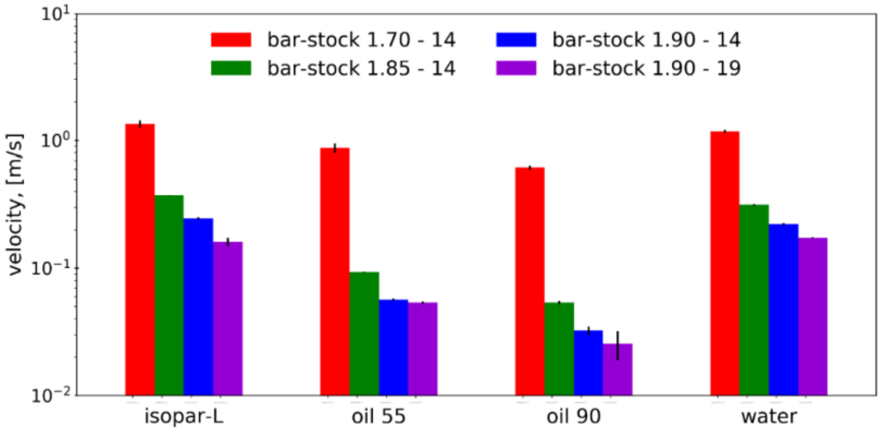


**Figure 5: Plunger Fall Velocity for Bar Stock Plungers with Different OD Tested in Static Liquid Columns.**

For continuous-flow plungers, the effect is much weaker (**Figure 6**). Tests on sleeves and bypass plungers showed only a marginal reduction in fall velocity with larger OD. Unlike bar-stock plungers, these designs still allow fluid to pass through the plunger during the fall stage, so a small decrease in clearance between plunger OD and tubing ID does not strongly alter the fall behavior.

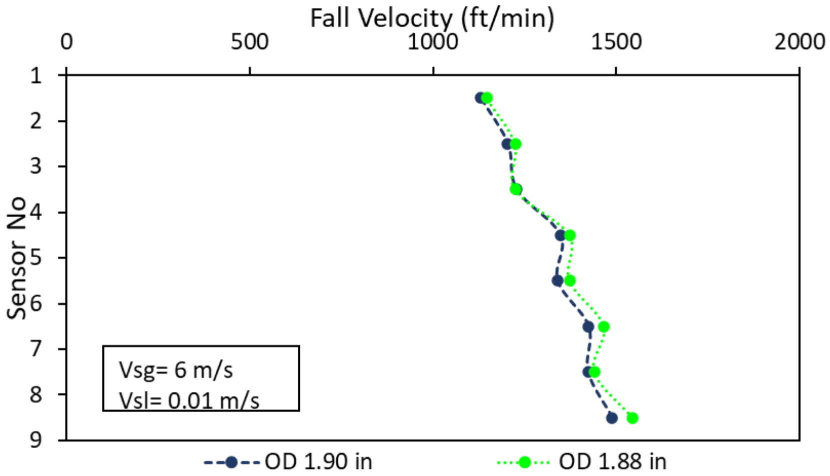


**Figure 6: Fall Velocity of Sleeves (Two-piece Plunger) with Different Outer Diameter Against Multiphase Flow.**

Referenced experimental and field studies, along with typical plunger vendor catalog listings, show that bypass plunger ODs are commonly available in the following ranges: 1.88 to 1.90 in. for 2-3/8 in. tubing, and 2.30 to 2.34 in. for 2-7/8 in. tubing. These correspond to plunger OD-to-tubing ID ratios of roughly 0.94 to 0.96.

For 3-1/2 in. tubing with a 2.992-in. ID, a 2.855-in. plunger gives a relatively high OD-to-ID ratio. While that may be acceptable during normal operation, a slightly smaller plunger would have been a more conservative choice for the initial run, especially in a well that had produced for years without plunger cycles and may have had scale or paraffin buildup. Starting with about 2.82 in. OD and increasing later to 2.855 in. OD would likely have reduced that risk.

### Plunger ID (Inner Orifice)

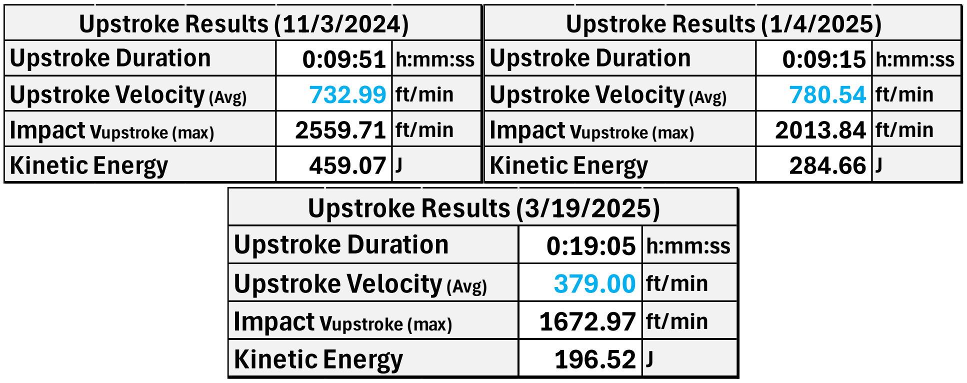
Review of bypass plungers used in 2-3/8 in. and 2-7/8 in. tubing showed that the inner and outer dimensions are generally scaled in a proportional manner. For the plunger used in this well, the vendor drawing showed an inner orifice of 1.25 in., which is smaller than typical five-slot bypass plungers. Earlier studies on 2-7/8 in. bypass plungers tested from different vendors measured the inner orifice to be around 1.42 to 1.55 in.

From 2-7/8 in. to 3-1/2 in. tubing, both tubing ID and plunger OD increase by roughly 20%. Based on that scaling, the inner orifice for this plunger would be expected to be closer to about 1.8 in. rather than 1.25 in. The small inner orifice made the plunger overly restrictive and was identified as the main reason it could not fall against the higher flow rates expected for a five-slot bypass plunger.

The reduced inner-orifice size also increased wall thickness and overall plunger weight. However, the added thickness was concentrated mainly in the middle section, while the upper section remained the same thickness as other plungers. Since wall-thickness-related mechanical integrity is ultimately controlled by the weakest section of the plunger body, increasing thickness only in the middle did not provide a meaningful structural benefit, while the added weight increased impact concerns.

Bypass Plunger Kinetic Energy at Impact for 3-1/2" Tubing

PAGL mechanistic simulations generate fall and upstroke velocity profiles, including the estimated impact velocity at the bumper spring and at the lubricator. The three simulation cases were reviewed to estimate kinetic energy during impact. Average upstroke velocity ranged from about 400 to 800 ft/min. As the plunger moves upward, gas expansion in the upper part of the well increases gas velocity and drag force, which further accelerates the plunger. Under the simulated conditions, impact velocity at the lubricator was estimated to reach 2500 ft/min. For a 14.5-in. bypass plunger with an assumed weight of 12 lb, this corresponds to kinetic energy values up to 450 J (**Table 2).**



| **Upstroke Results (11/3/2024)** | | |
|---|---|---|
| **Upstroke Duration** | **0:09:51** | **h:mm:ss** |
| **Upstroke Velocity** (Avg) | **732.99** | **ft/min** |
| **Impact Vupstroke (max)** | **2559.71** | **ft/min** |
| **Kinetic Energy** | **459.07** | **J** |

| **Upstroke Results (1/4/2025)** | | |
|---|---|---|
| **Upstroke Duration** | **0:09:15** | **h:mm:ss** |
| **Upstroke Velocity** (Avg) | **780.54** | **ft/min** |
| **Impact Vupstroke (max)** | **2013.84** | **ft/min** |
| **Kinetic Energy** | **284.66** | **J** |

| **Upstroke Results (3/19/2025)** | | |
|---|---|---|
| **Upstroke Duration** | **0:19:05** | **h:mm:ss** |
| **Upstroke Velocity** (Avg) | **379.00** | **ft/min** |
| **Impact Vupstroke (max)** | **1672.97** | **ft/min** |
| **Kinetic Energy** | **196.52** | **J** |

**Table 2: Plunger Upstroke Velocity and Kinetic Energy at Impact for Different Production Rates**

Recent field studies from 2-7/8 in. tubing PAGL applications with 19.5-in. bypass plungers showed upstroke impact kinetic energy results in the range of 300 to 400 J. Since kinetic energy depends strongly on both plunger velocity and weight, the main difference for the 3-1/2 in. application is the heavier plunger rather than unusually fast upstroke. A larger OD increases plunger weight, while the shorter 14-in. body partly offsets that increase. Overall, impact energy is not expected to increase substantially unless the plunger is surfaced with aggressively high upstroke velocity because of excessive injection, dry-run conditions, high GLR, or similar factors. Fall velocity kinetic energy was found to be marginal compared to the upstroke.

## Solution – New Plunger Design

Once the undersized inner orifice was identified as the main cause of the cycling problem, the recommendation was to redesign the plunger with dimensions scaled more proportionally to standard bypass plungers used in other tubing sizes. Increasing the inner-orifice size was expected not only to improve fall performance, but also to reduce steel thickness and overall plunger weight, which would help lower impact force and kinetic energy.

The custom 3-1/2 in. five-slot bypass plunger was then redesigned using proportions closer to the vendor's standard bypass plungers for 2-3/8 in. and 2-7/8 in. tubing. The new plunger was installed on June 11, and early field results reported that it was able to complete cycles at total gas flow rates up to about 2.9 MMscf/d. As gas rate declined, the afterflow setting was adjusted at the wellsite to around 2.5 MMscf/d.

After deployment of the redesigned plunger, PAGL operation was established with a shut-in time of about 2 min 30 sec, and the plunger cycling problem was resolved. **Figure 7** shows the running-average trends of daily total gas and liquid rates. Following installation of the proportionally designed bypass plunger, both gas and liquid production increased over the next several weeks. The well experienced some downtime on certain days during the following weeks, but this was reported to be related to the well pad, injection capacity, and surface facilities rather than the plunger design.

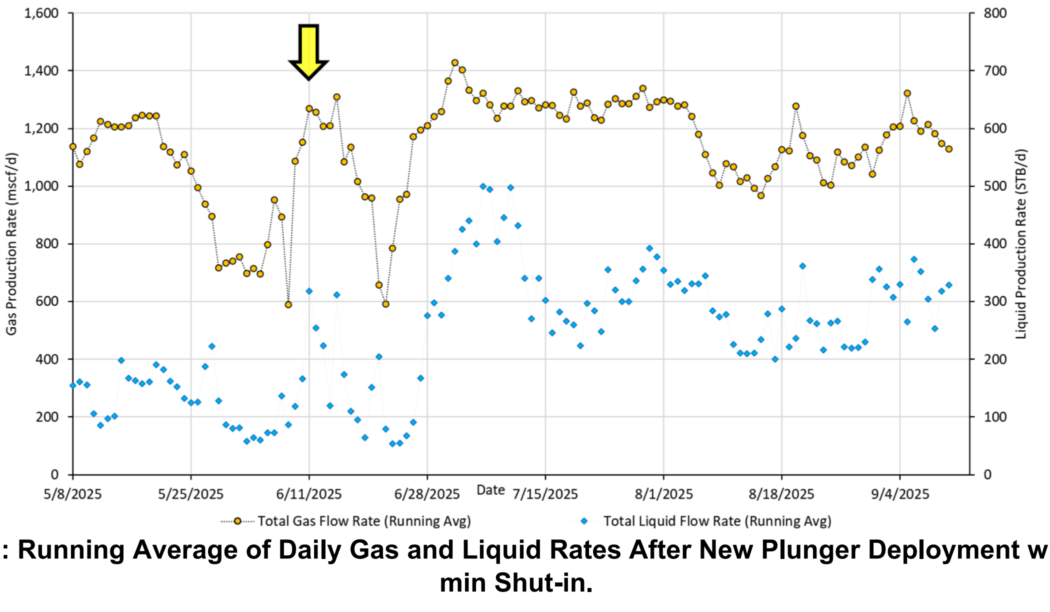


**Figure 7: Running Average of Daily Gas and Liquid Rates After New Plunger Deployment with 2.5-min Shut-in.**

## Conclusions

This study shows that 3-1/2 in. tubing is suitable for continuous flow plunger lift, specifically Plunger-Assisted Gas Lift (PAGL). By utilizing drag-based mechanistic models, operators can accurately estimate operational ranges and plunger cycles even for datasets not encountered during the initial modeling phase. These physics-based tools provide a significant advantage over purely data-driven or experience-based decision-making, allowing engineers to account for critical variables including different BHA depths, tubing size, production rates, gas-to-liquid ratios (GLRs), injection rates, plunger types and more. Ultimately, these models serve as a vital screening tool to optimize production and determine the most effective timing for plunger deployment, transition from gas lift to PAGL and GAPL.

The study showed that decreasing the inner orifice of a bypass plunger can significantly reduce plunger fall velocity. For five-slot bypass plungers, the bottom side openings are not necessarily the most restrictive part of the flow path. In this case, once that design issue was identified and a proportionally designed 14-in. five-slot bypass plunger was manufactured, the operational problem was resolved. The redesigned bypass plunger was then able to cycle continuously with about two minutes of shut-in time without requiring a reduction in gas flow rate.

Transitioning gas lift wells to PAGL provides a sustainable method to mitigate liquid loading for years without requiring higher gas-injection rates. This strategy offers a practical, low-cost alternative to tubing replacement workovers, which are often expensive and require downtime. As production rates continue to decline, these wells can eventually be transitioned into intermittent production with conventional plungers with GAPL. By integrating mechanistic models, feasibility analysis can be made for field-wide decision-making, operators can more effectively allocate compression capacity and defer or postpone major capital expenditures like tubing replacement.

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