I-PLUNGER---A LOOK DOWNHOLE

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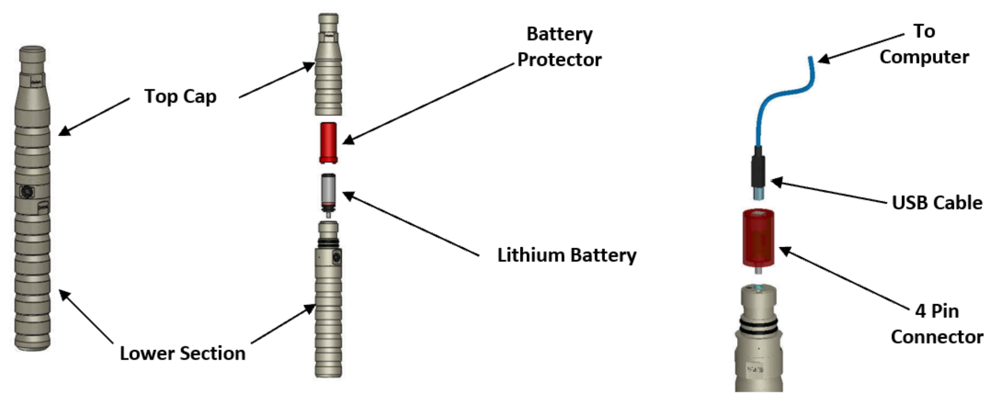
INTRODUCTION: THE I-PLUNGER

The I-Plunger is a specialized downhole instrumentation tool designed for natural gas producing wells, which records essential metrics including pressure, temperature, depth and plunger velocity. The collected data is then analyzed using custom software, providing detailed insights through graphical representations.



Data obtained from the I-Plunger serves various purposes, including optimizing plunger lift, gas lift, and GAPL/PAGL operations. Proper utilization of data may effectively aid in configuring dual-stage plunger setup, verification of plunger travel path to ensure the plunger reaches ideal depth, determination of fall and rise characteristics in deviated wellbores, as well as identifying and monitoring changes in fluid levels, producing bottom-hole pressures, and bottom-hole temperatures. Wellbore anomalies such as holes in tubing, corrosion, and failed gas lift valves are often determined easily determined by analyzing the graphical data presented by the software interface. Additionally, I-plunger data may help determine operational challenges such as multi-well pad interference and production effects from field compression. Furthermore, I-plunger data can be utilized in well fracturing and off-set production interference testing, pulse testing, assessment of horizontal well interference, and to effectively gather critical bottom hole pressure and temperature data needed for calculating reservoir properties with other diagnostic software programs.

The I-Plunger software interface allows the field user to initiate data collection setpoints on location in prior to survey onset by connecting to the battery/data 4 pin port via RS232 connection. After setpoints have been configured and the I-plunger is initialized, data will begin recording and time stamp accordingly when the battery is inserted into the 4-pin port. The I-plunger is then assembled and torqued accordingly to ensure pressure and mechanical integrity. Upon survey completion, the I-plunger is disassembled, and the battery is removed. The RS232 adaptor is inserted into the port, and data can be downloaded via USB to the field user's desired location utilizing the software program. Data can be uploaded quickly to the charting interface, and can be used to optimize operational efficiency, increase production, and identify reservoir management properties all while being onsite with minimal effort in a time efficient manner. When I-Plunger data is combined with surface pressure data, facilities and compression effects can be further evaluated in more detail and optimized accordingly.

The following data surveys have been collected from a variety of plunger-lift, gas-lift, and GAPL/PAGL producing wells. I-plunger data collected and utilized in a detailed analysis of a gas lift well evaluation for conversion to Plunger Assisted Gas-Lift (PAGL) is also depicted. These data sets are shown as graphical representations for review.

I-PLUNGER OVERVIEW AND TYPICAL WELL CYCLE

"Deviation" from the Typical Plunger Cycle in (Figure 1) is indicative of changes in well behavior, which can occur from multiple sources and often resulting from liquid loading, various down-hole mechanical issues (such as gas lift valve failure, holes in tubing, corrosion and mechanical erosion of tubing, formation of scale and paraffin), line pressure increases, changes in operations (such as facility malfunctions), compression loading/restrictions, stimulation interference (frac hits), or possible interference effects from other wells, etc.

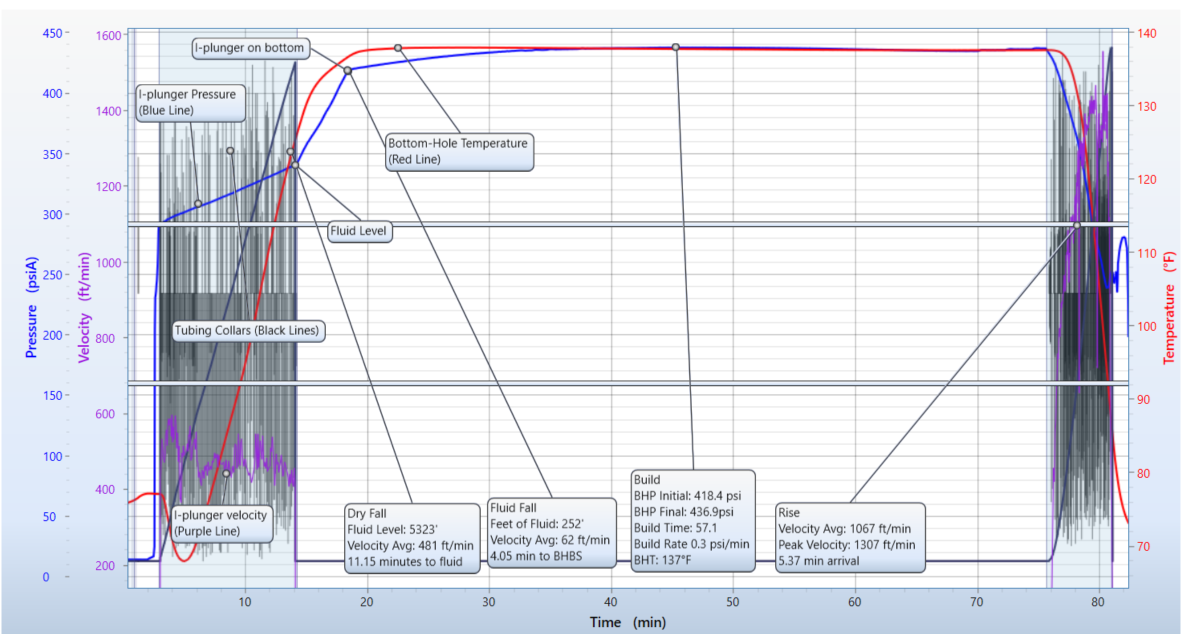


Figure 1

It is often found that plunger lift wells are running consistently but may not be optimized due to limited data available to provide insight into the characteristics of each well individually. The well shown in Figure 1 is a traditional plunger lift well with 2-3/8 tubing and 4-1/2” casing which ran very consistent with a bar style plunger, resulting in few operational changes to plunger program times. Determining fall and rise profiles and identifying build characteristics may be necessary to properly optimize well production.

Typical I-Plunger Cycle: Consistent operation---BUT not Optimized

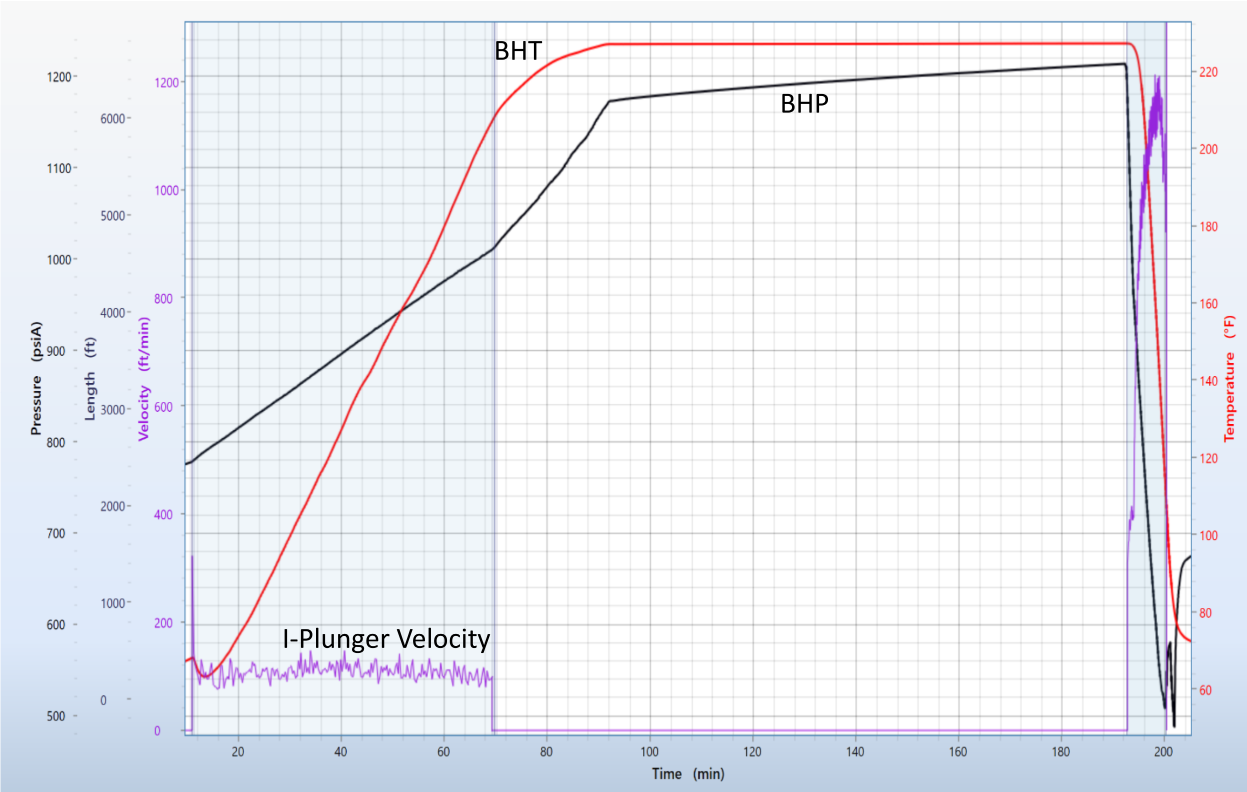


Figure 2

Figure 2 shows an overview of a full plunger cycle (dry fall, fluid fall, build stage, rise) on a traditional 2-3/8” plunger-lift well. I-Plunger fall and rise profiles from Figure 2 are presented individually in an expanded graphical view below in Figure 3 and Figure 4. This graphical expansion allows for a more detailed evaluation of down-hole parameters to determine possible wellbore anomalies and identify plunger lift program operational changes that may result in enhanced production. These parameters include but are not limited to:

- Fall and Rise Velocity
- Fluid Level, Bottom-hole Pressure, Bottom-hole Temperature
- Build Time (amount of time plunger has reached bottom hole spring assembly but remains shut in)

I-Plunger Fall

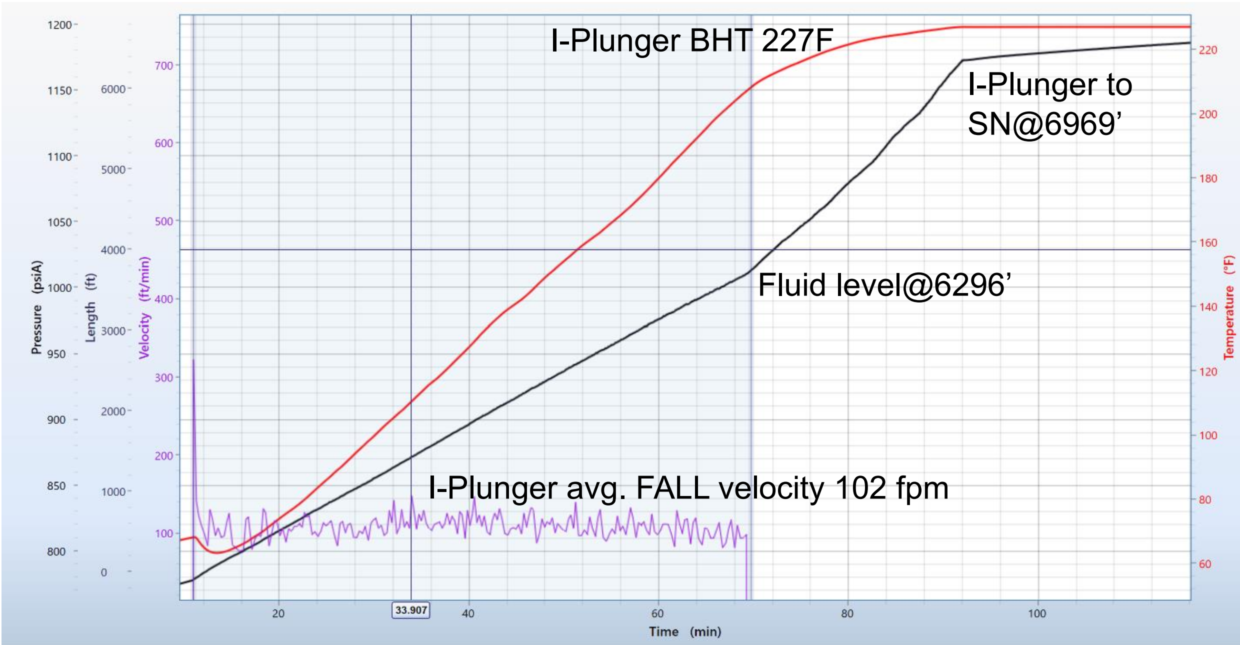


Figure 3

The well shown in the graph has a dry fall velocity of 102 ft/min, fluid level is at 6296', bottom hole spring assembly is at 6969'. The well has a 673' fluid column in the tubing.

I-Plunger Rise

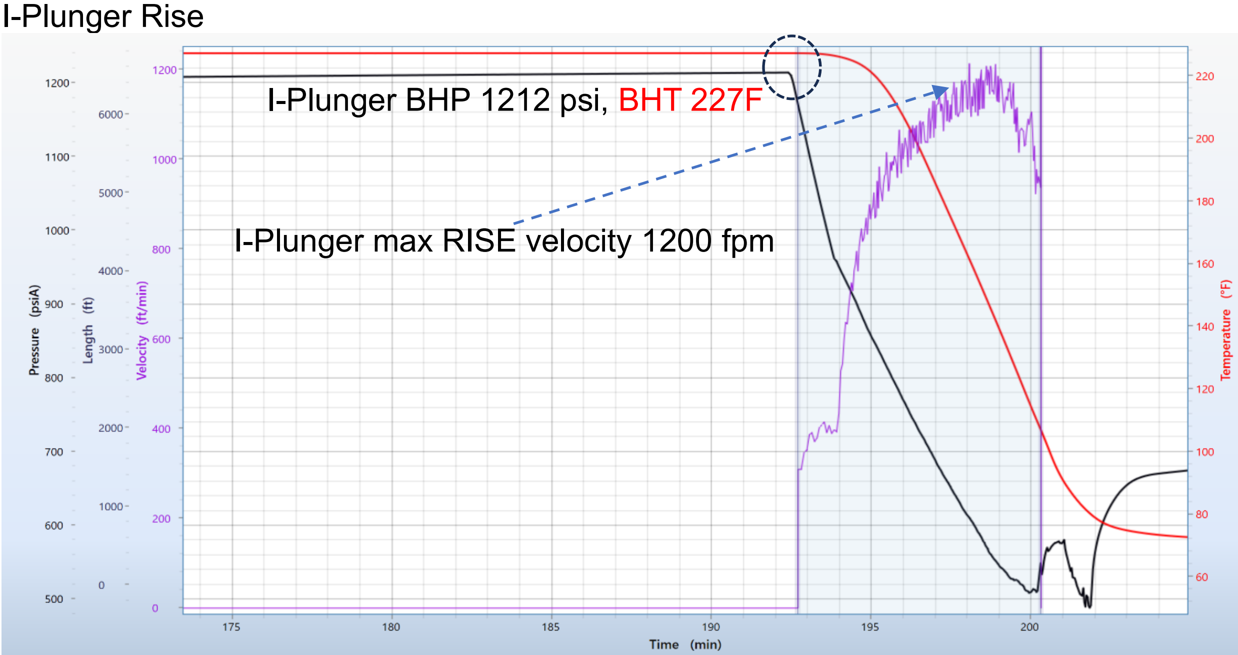


Figure 4

The graph shows that the well has an average velocity arrival time of 985 ft/min, a peak velocity of 1200 ft/min, and a build time of over 100 minutes.

Although the well operates consistently, it appears to be running suboptimal, evident from the elevated fluid level, extended shut-in periods, and high arrival velocity. Implementing a plunger with a higher fall velocity, combined with reduced shut-in times could enhance oil and gas production while potentially reducing plunger velocity, thereby minimizing fluid slippage, decreasing bottom-hole pressure, and mitigating potential damage to the plunger and lubricator. It's notable that surface monitoring indicates an average rise velocity of 985 feet per minute (fpm) based on time and depth calculations, contrasting with the actual arrival velocity recorded by the I-Plunger at 1200 ft/min. This discrepancy underscores the significant variance that can exist between calculated average velocities and real-time surface arrivals.

I-PLUNGER RISE / FAULTY CONTROL VALVE

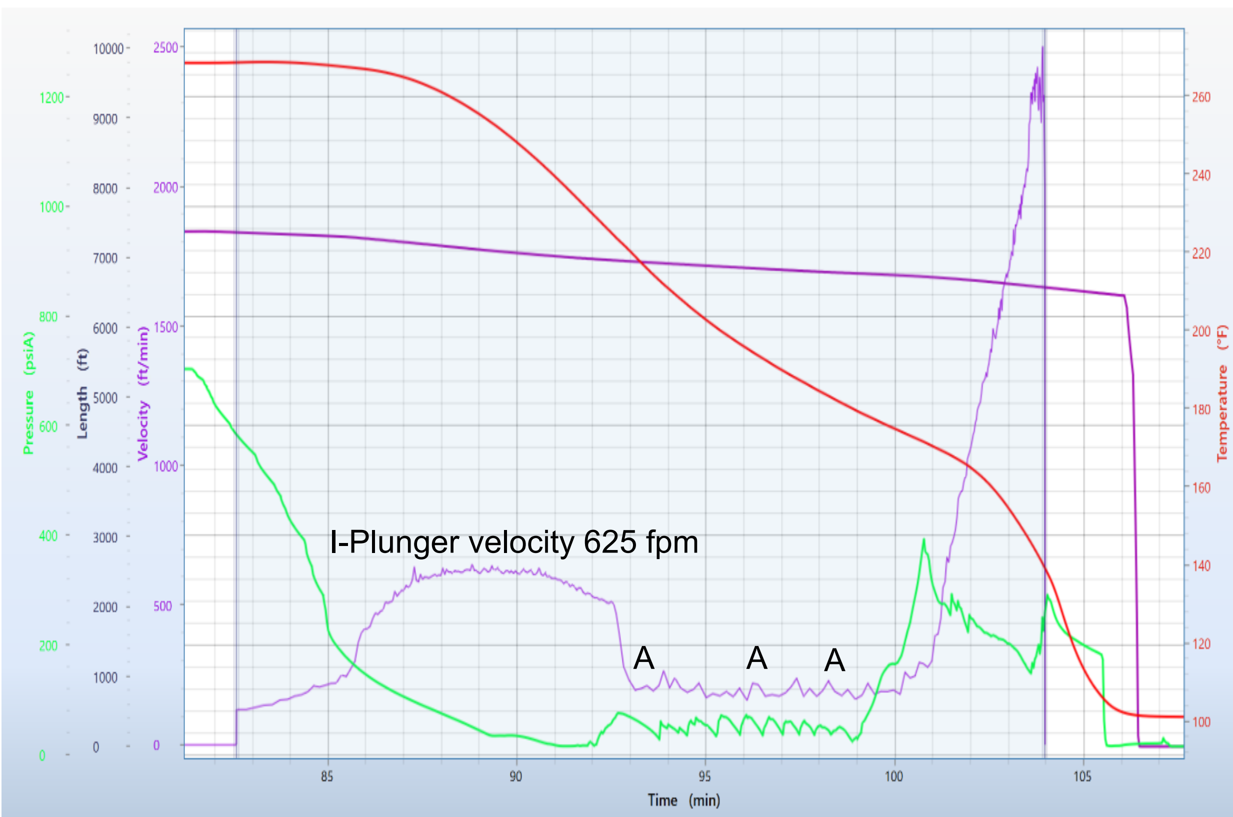


Figure 5

Figure 5 demonstrates a rise profile in which the plunger slows down significantly, although it still emerges from the hole with fluid. A malfunctioning control valve at the surface, as depicted in Figure 5 (A), was identified as an underlying issue, observed to be chattering closed during the rise cycle, resulting in plunger velocity reduction. As fluid cleared the surface equipment and the control valve reopened, back-pressure was significantly reduced, resulting in a rapid acceleration for the remainder of the wellbore. The final plunger velocity exceeded 2400 ft/min, with an average velocity of 500 ft/min.

This incident serves as a prime example of how average rise velocity can obscure other mechanical issues that may potentially lead to lubricator failure and create a potentially dangerous work environment.

GAS LIFT VALVE FAILURES

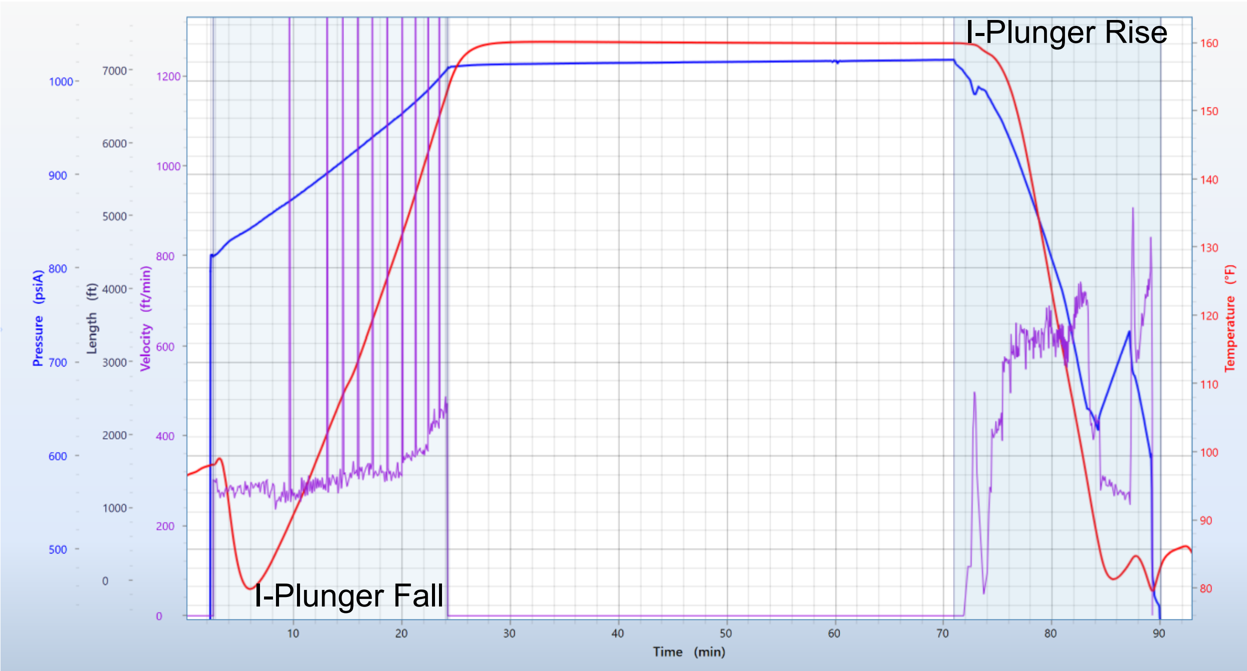


Figure 6

The example from Figure 6 depicts a well with 12 gas lift valves installed. However, the I-Plunger's descent stopped just beyond the 10th gas lift valve from the surface. This discrepancy suggests potential issues with gas lift valve functionality. When gas lift valves fail in the open position, the pressure and temperature changes can contribute to scaling problems within the wellbore, ultimately preventing the ability of the plunger to reach fluid in the tubing, thus hindering well production and creating further operational complications.

Early identification of wellbore obstructions or malfunctions within the gas lift system are essential to minimize production decline and ensure gas lift efficiency.

Moreover, the presence of scaling due to stuck gas lift valves can exacerbate production challenges over time. Scaling not only reduces the efficiency of gas lift operations but also poses risks of wellbore blockages and increases the potential to make wireline and workover operations increasingly difficult.

I-Plunger Rise Against Faulty Gas Lift Valves

Figure 7

In Figure 7, the graph depicts several gas lift valves that appear to be either leaking or failed in the open position. Identified leaky valves (marked as point A) accelerated the I-Plunger upwards. Meanwhile, a stuck-open valve (marked as point B) caused the I-Plunger to stall. After passing the open valve (marked as point C), the I-Plunger accelerated rapidly towards the surface.

This inefficiency might not be immediately apparent at the surface and could easily go unnoticed. Often, when production declines as a result of the early stages of gas lift failure, operators tend to increase the gas injection rate to compensate for decreased production as they are unaware of the inefficiencies occurring in the gas lift system. Such injection rate increases may be unnecessary as they are more likely masking the underlying incompetencies of an aged or faulty gas lift system. This injection rate increase could further contribute to decreased production by exerting unnecessary pressure on the wellbore.

Gas Lift Valve Stuck Open

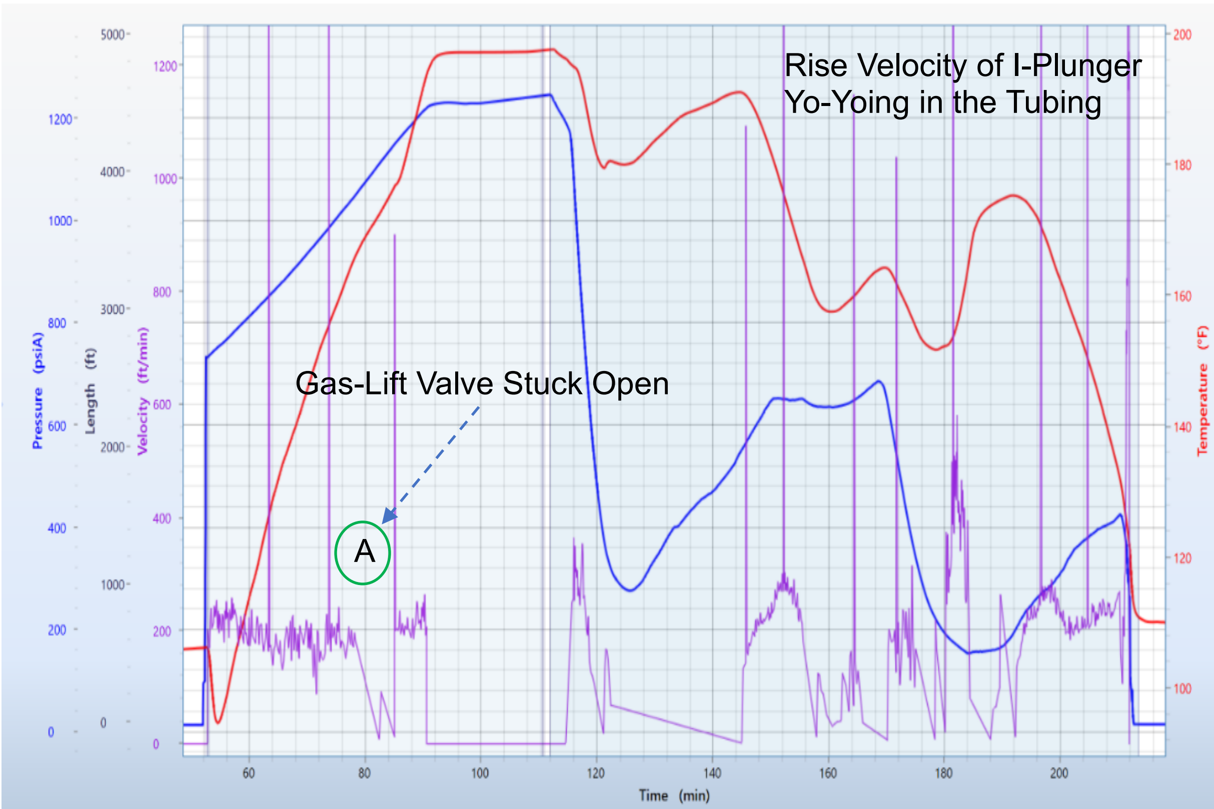


Figure 8

In Figure 8, it's noted that there are 11 gas lift valves installed in the well. However, the I-Plunger's descent was impeded, halting just past the 3rd gas lift valve from the surface. A notable reduction in velocity occurs as the I-plunger approaches the 3rd valve from surface (marked as point A). A cooling effect is detected on the I-plunger, visible on the charted temperature. This is often seen when a gas lift valve has failed in the open state, due to the turbulent area that occurs from gas entering the tubing at the failed valve. After the I-plunger has crossed this turbulent area, the downward force of the gas being exerted above the I-Plunger results in a sudden increase in fall velocity. This observation indicates significant issues with the gas lift valve functionality, impacting the well's operational efficiency. A more in depth look at the fall velocity is shown in figure 9.

Of particular interest is the erratic velocity observed during the rise to the surface, attributed to an unwanted open gas lift valve. The continued turbulent effects in this area subsequently stalled the I-Plunger.

Understanding and addressing such anomalies are crucial for maintaining optimal production levels and ensuring the integrity of the gas lift system.

Gas Lift Valve Failed Open-Fall Cycle

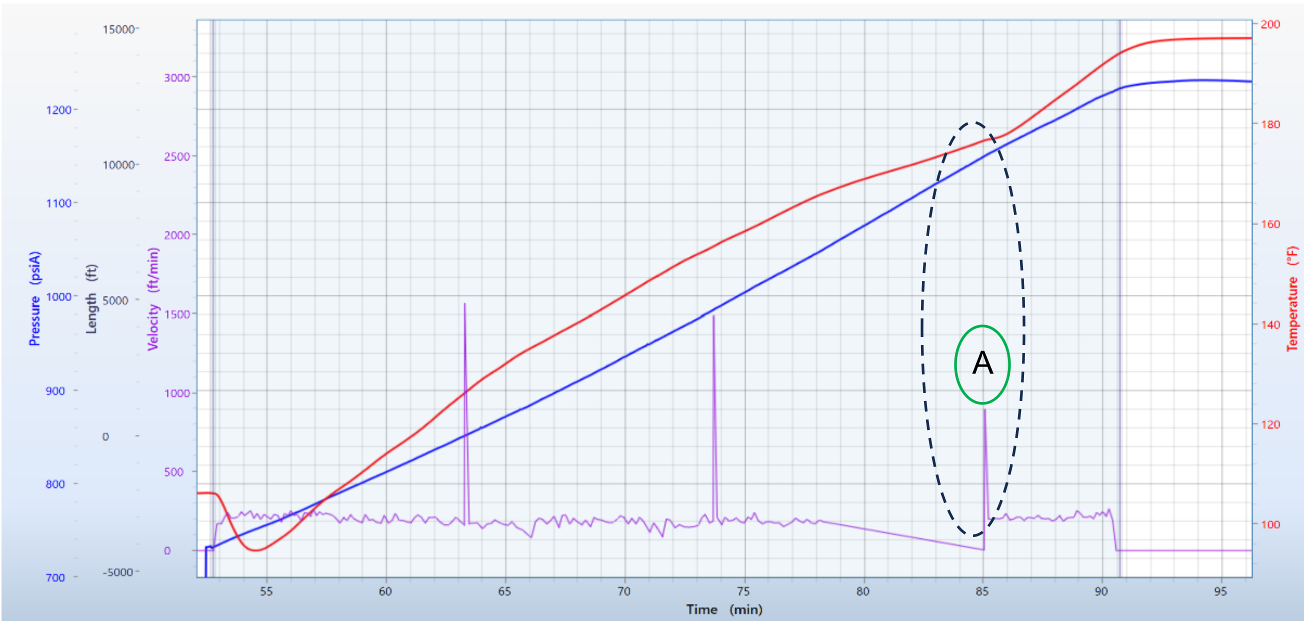


Figure 9

This figure depicts an expanded view of the fall cycle from the well shown in figure 8.

<u>FLUID ABOVE FAILED GAS LIFT VALVE</u>

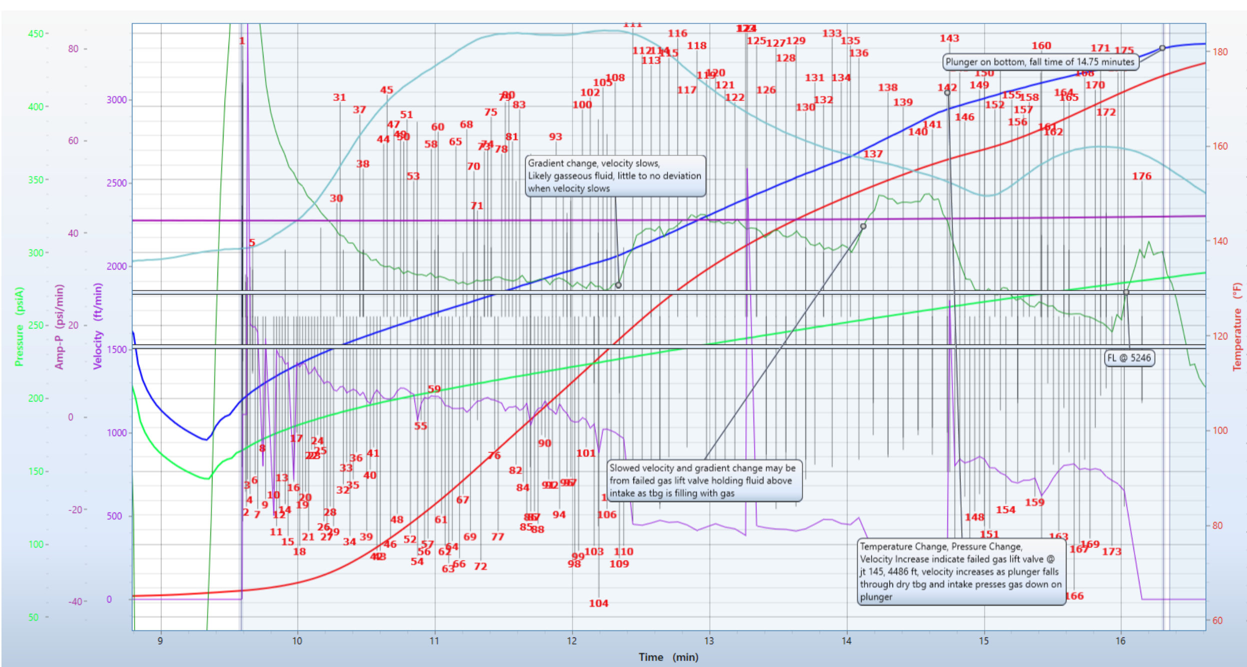


Figure 10

One advantage of utilizing the I-plunger lies in its ability to provide insights beyond fluctuating fluid gradients. In Figure 10, the turbulent area created by the failed gas lift valve is great enough to effectively hold a gaseous fluid pocket above it. The I-plunger velocity slows, and pressure increases as it falls through this gaseous fluid column. Subsequently, after passing the failed valve, a gradient change of pressure is noted as the I-plunger falls through a dry pocket and scattered fluid. The I-Plunger offers data beyond this fluid pocket to the entire depth it travels, effectively showcasing the malfunctioning valve and accurately indicating the location of gaseous fluid pockets and fluid level within the well.

This scenario underscores the instrumented plunger's capability to diagnose issues such as malfunctioning valves, as well as identifying the appropriate fluid levels even when being obstructed by fluid pockets. Similarly, the instrumented plunger can be utilized in detecting holes in tubing situated below fluid levels, effectively providing comprehensive diagnostics.

<u>EVALUATING A ROD PUMP WELL FOR GAPL</u>

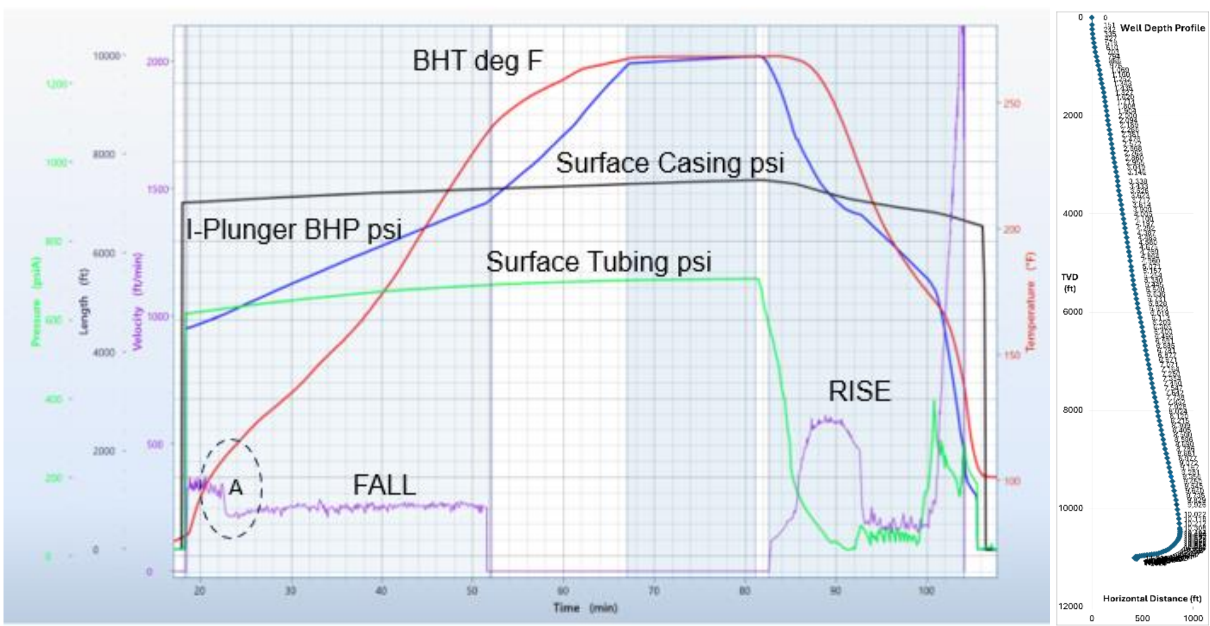


Figure 11

Previously, this well operated on a pumping unit with a Gas-to-Liquid Ratio (GLR) of 1800 standard cubic feet per barrel (scf/bbl), with the tubing set at a depth of 10,659 feet. However, due to an increasing occurrence of tubing and rod failures as a result of wellbore deviation (wellbore profile depicted on the right), the decision was made to survey the wellbore in order to assess the feasibility of Gas-Assisted Plunger Lift (GAPL), or alternatively, the feasibility of dual-stage plunger lift, as an alternative method of artificial lift.

Subsequently, the well was converted to GAPL. An I-Plunger was deployed into the well and cycled back to the surface, revealing 984 feet of fluid in the tubing. The successful cycling of the I-Plunger indicated the potential for the well to produce with additional gas injection, and existing infrastructure made GAPL a viable alternative.

During the fall, there is an observation of a tubing Inner Diameter (ID) change (marked as point A). This change in tubing ID was detected during the descent of the I-Plunger, providing valuable insights into the wellbore configuration and facilitating further assessment of operational parameters.

GAS LIFT WELL CONVERTED TO GAPL

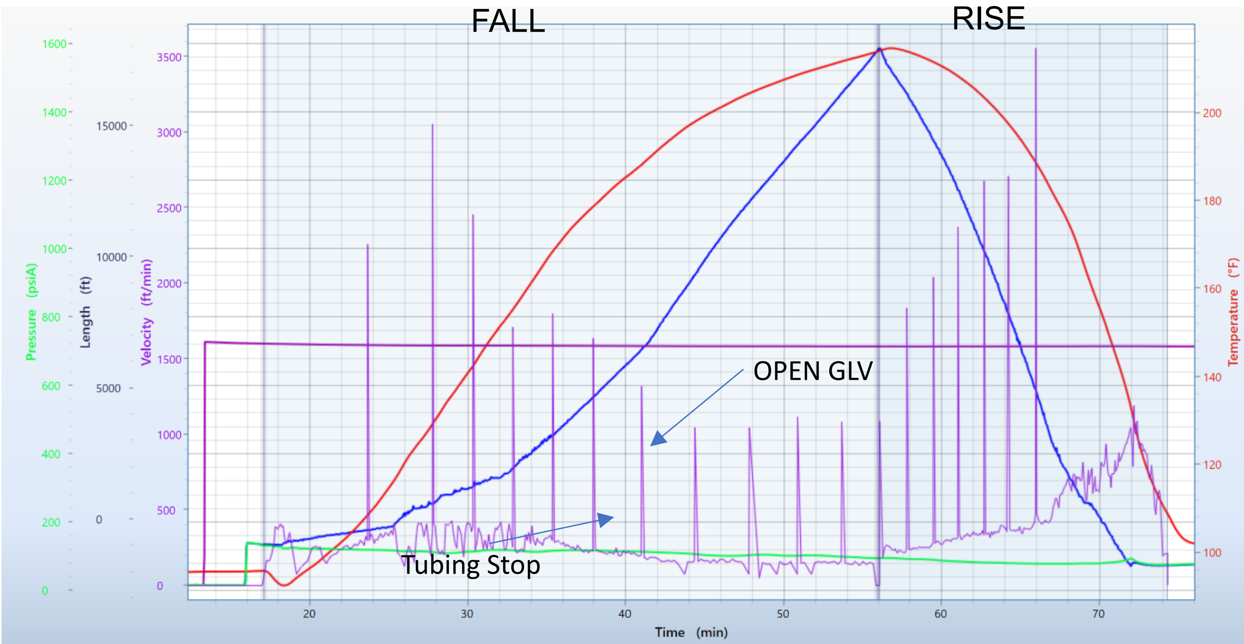


Figure 12

As production continued to decline on the well shown in Figure 11, the operational viability of the well became increasingly uneconomical. Suspicions arose regarding the presence of open gas lift valves within the system, The gas lift system consisted of 11 gas lift valves and an open orifice in the tubing string.

In preparation for an I-Plunger run, the well underwent broaching procedures. Subsequently, an I-Plunger was slick-lined to the seating nipple located at 8,853 feet, with a packer set at 8,857 feet.

Upon investigation, it was determined that a high fluid level was present at 6,494 feet, with gassy fluid extending down to 2,153 feet. Analysis of Gas Lift Valve pressure settings and pressure gradient changes informed the decision to set a tubing stop at 6,400 feet (as depicted in Figure 12). Subsequently, the well was transitioned to Gas-Assisted Plunger Lift (GAPL) utilizing a clutch-style fast-fall plunger.

The tubing stop was strategically positioned just above the 7th gas lift valve from the surface. This decision was based on the determination that this valve was open, thereby allowing for fluid clean-up operations to occur effectively and contribute to improved production performance.

TESTING DIFFERENT INSTRUMENTED PLUNGER TYPES

Ongoing efforts are underway to diversify instrumented plunger offerings in terms of types and sizes. Presently, solid I-Plungers are available (depicted in Figure 15), alongside a 'dart' style bypass design (illustrated in Figure 14) with recorded fall velocities averaging around 800-1200 feet per minute (ft/min). Additionally, instrumented ball and sleeve plungers, or variants resembling a sleeve configuration, are undergoing testing (depicted in Figure 13).

Instrumented plungers that emulate the fall characteristics of production plungers are crucial for optimizing wells utilizing plunger lift as a primary or secondary method of de-liquification. By accurately replicating the behavior of production plungers, these instrumented devices play a pivotal role in enhancing the efficiency and effectiveness of plunger lift systems deployed in oil and gas production operations.

The following graphs are from consecutive surveys that were conducted on the same well in order to compare the rise and fall characteristics of various plungers in a consistent environment. These surveys aimed to provide insights into the performance variability of the plungers under similar operational conditions and identify any trends or patterns that may emerge.

Instrumented Ball and Sleeve

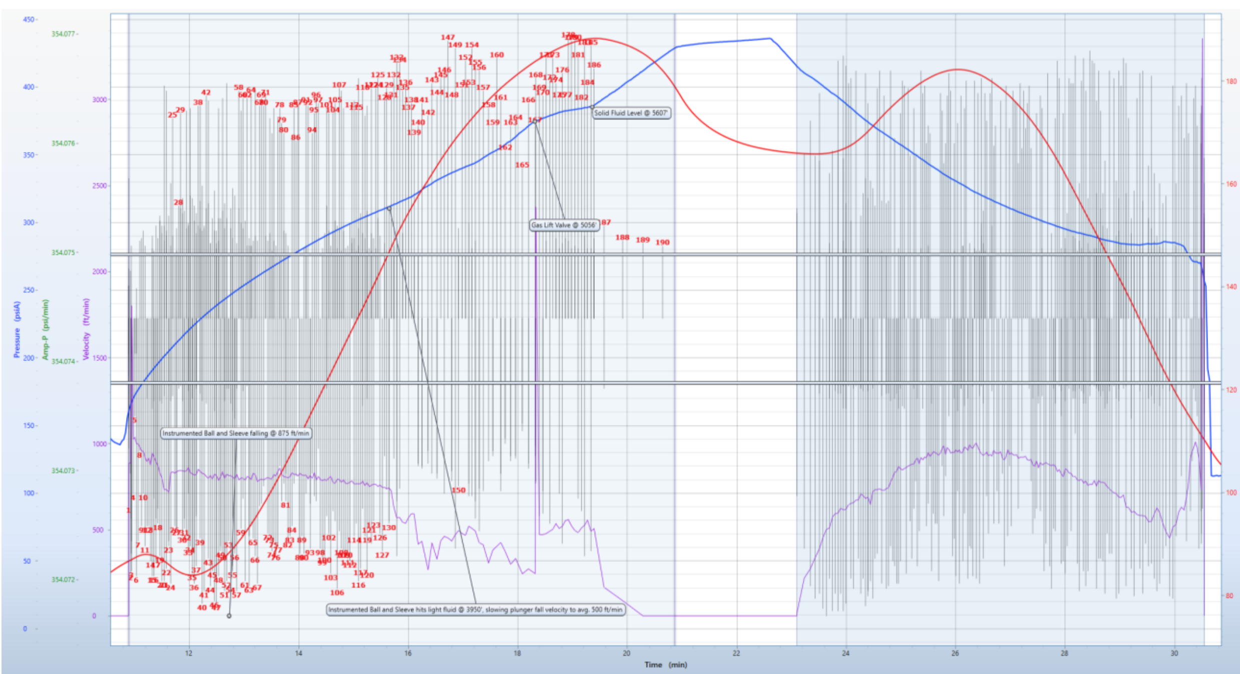


Figure 13

This graph shows fall and rise velocity of the instrumented ball and sleeve, falling at speeds of over 1000 ft/min in the vertical section of the wellbore. Velocity slows to 875 ft/min as the plunger enters deviation. Gaseous fluid present in the tubing reduces fall velocity which becomes unstable and ranges from 400-600 ft/min. Fluid fall rate of 80-100 ft/min is lower than was anticipated.

Instrumented Dart Bypass

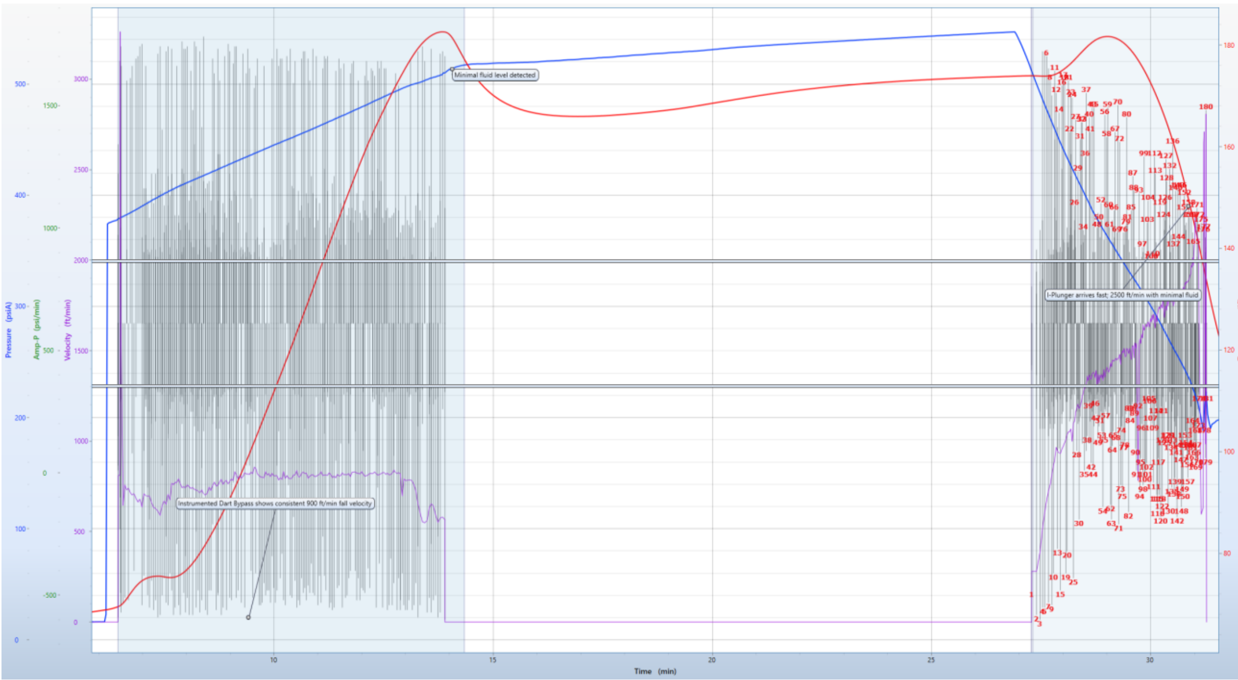


Figure 14

This graph depicts the fall and rise velocity of the instrumented bypass plunger. In contrast to the ball and sleeve, this plunger falls slower in the vertical section (around 700 ft/min), then increases to around 900 ft/min in the deviated section of the wellbore. Velocity begins to slow significantly near the bottom of the wellbore as the plunger enters the horizontal kickoff point. No fluid was present in the tubing during the survey.

Instrumented Barstock

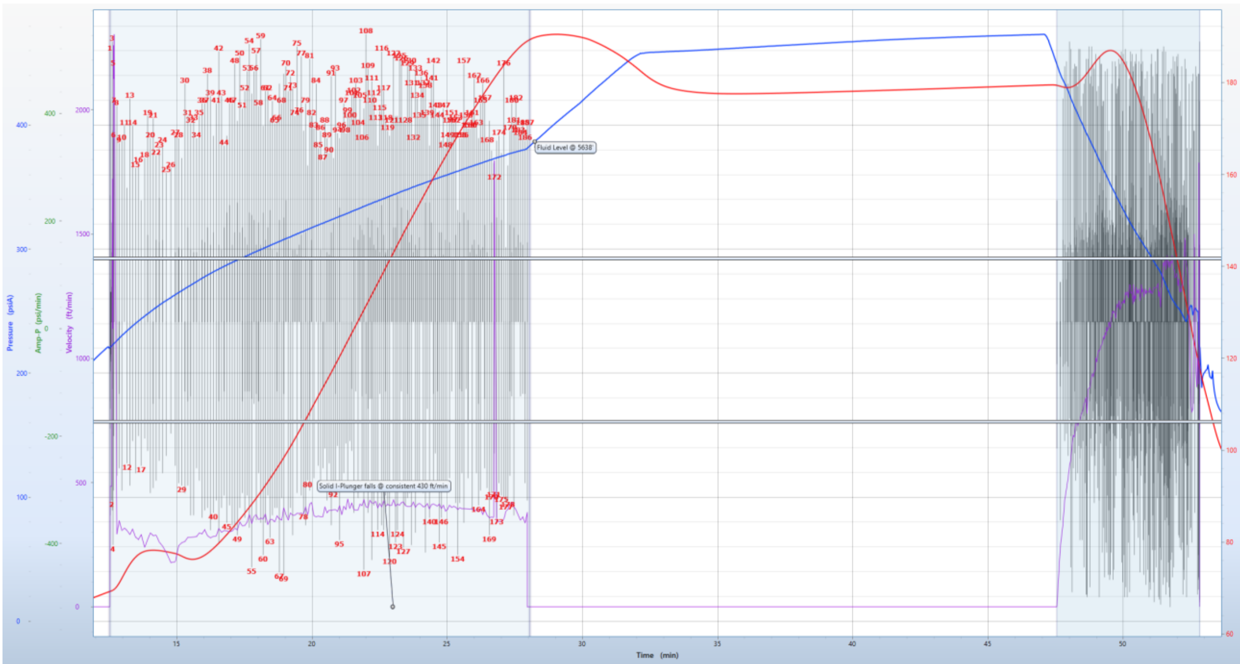


Figure 15

This graph shows the characteristics of a bar-stock instrumented plunger in order to serve as a baseline for the bypass and ball and seat plunger types. It is noteworthy that this plunger also had a higher fall velocity in deviation than the vertical section of the wellbore. Given the slower falling nature of this plunger (350-400 ft/min) the fluid in the tubing had settled into a solid column and was not present as gaseous pockets as observed during the ball and sleeve survey.

<u>CONCLUSION</u>

In conclusion, utilizing of the I-Plunger for downhole monitoring and diagnostics, field users can gain valuable insights into the condition of their plunger lift based systems, which can enable targeted interventions to optimize production and mitigate potential risks associated with operational inefficiencies.

The insights gathered from the analysis of instrumented plunger data within various wellbore environments provide insight into proper plunger selection, ideal operational setpoints for plunger programs, down-hole conditions, and fluid dynamics. The information found within this excerpt provides information on performance characteristics exhibited by different wellbore conditions and anomalies.

The findings reveal the immense benefit of utilizing instrumented plungers, shedding light on characteristics ranging from rapid descents in vertical sections to slower velocities in deviation, influenced by the presence of gaseous fluids and environmental factors. Notably, discrepancies in fall velocities and fluid behavior emphasize the need for tailored approaches in plunger lift optimization.

Moreover, the study underscores the pivotal role of advanced diagnostic tools like the I-Plunger in facilitating real-time monitoring and assessment of well performance. By leveraging such technologies, operators can make informed decisions to enhance production efficiency, mitigate risks, and optimize reservoir management strategies.

Moving forward, continued research and development efforts in instrumented plunger technologies are essential to further refine operational methodologies and address evolving challenges in oil and gas production. Utilizing these innovations, operators can enhance plunger lift optimization more effectively.