INSIGHTS INTO INTERMITTENT GAS LIFT: LESSONS FROM FIELD EXPERIMENTS AND OPERATIONS

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ABSTRACT

Intermittent gas lift (IGL) is emerging as a key late-life artificial lift method for the growing number of aging Permian Basin horizontal wells. With more than 20,000 wells on continuous gas lift, operators face challenges in conversion to IGL and its operation effectively. This study synthesizes lessons gathered from controlled IGL experiments at the Texas Tech Oilfield Technology Center (OTC) and multiple Permian Basin wells.

1. Tubing integrity presents a major barrier to successful IGL implementation. Perforation sealers and tubing patch systems offer a temporary fix. However, the corroded tubing strings left in a well for long can turn into expensive fishing jobs.
2. Proper IGL conversion depends on liquid fallback factor, tubing size, and depth of gas lift valve.
3. Flaws in the deployment method of standing valves affect their performance in IGL.
4. Reservoir depletion must be considered in the initial IGL design since the gas lift valve behavior alters with declining tubing pressures. The gas lift valve mechanics depend on the tubing pressure, so the valve opening pressure and spread change with declining tubing pressure.
5. High-frequency bottomhole pressure sensor data is essential for diagnostics and effective optimization of IGL.
6. Identified the operational similarities between sucker rod pumping and IGL.

These insights provide a practical framework to improve candidate selection, system design, and long-term intermittent gas lift success in unconventional reservoirs.

INTRODUCTION

Intermittent gas lift (IGL) has become an attractive method for late-life unconventional wells due to its relatively low cost and minimal downhole requirements. Unlike rod pumping systems, intermittent gas lift does not require extensive mechanical components in the wellbore, thereby reducing operational costs and risks. Intermittent gas lift is a cyclic production method that involves building up a liquid column in the tubing and injecting gas in the annulus between the casing and the tubing to produce the liquid (Carlson & Bordalo, 2017; Carvalho Filho, 2004). This type of gas lift is considered when the reservoir depletes, which makes it suitable for low-producing wells (Mantecon, 1993; Pittman, 1982).

Over the years, there have been studies conducted to understand the behavior of the liquid slug in intermittent gas lift (Brill et al., 1967; Liao, 1991; Neely et al., 1974; Schmidt et al., 1984). Studies have also examined which operational conditions hinder production and which facilitate higher recovery in intermittent gas lift wells (Winkler, 1959; Brown et al., 1962; Hernandez et al., 1997, 1998, 1999, 2001). Despite numerous studies, operators still face challenges in effectively implementing intermittent gas lift. Also, operators face the challenge of determining the optimal time to convert from continuous (CGL) to intermittent gas lift.

In this study, we present some of the important lessons we have learnt from two years of working on intermittent gas lift at the Texas Tech Oilfield Technology Center (OTC) and analyzing actual Permian Basin field data. Several important lessons were learnt from this study regarding the successful implementation and optimization of intermittent gas lift wells. These lessons would help operators understand intermittent gas lift operations and the surveillance required to operate them efficiently.

METHOD

Experimental Setup

Figure 1 shows the Red Raider #2 test well at the OTC, which is being used for intermittent gas lift experiments.

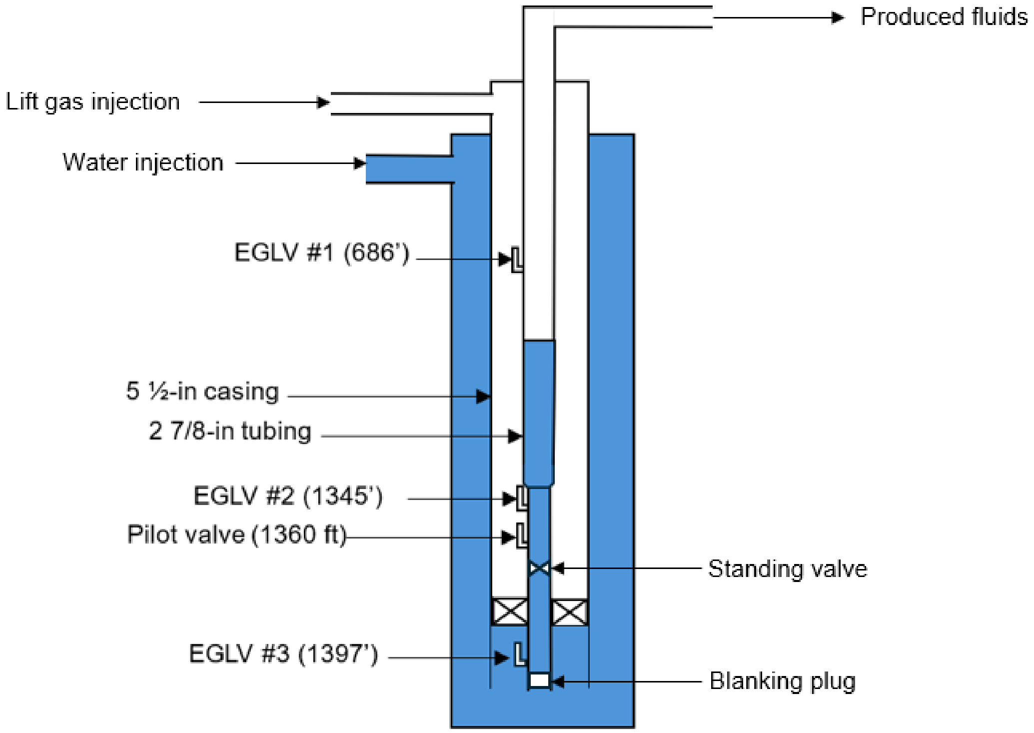

Figure 1: Schematic of the Red Raider #2 test well

The intermittent gas lift tests use potable water as the liquid and nitrogen gas as the lift gas. The test well consists of a 9-5/8-inch casing, a 5-1/2-inch casing, and a 2-7/8-inch tubing. The 9-5/8-inch casing is where water is injected for the tests. The 5-1/2-inch casing is where the lift gas is injected using a three-stage compressor for intermittent gas lift. The 2-7/8-inch tubing serves as the tubing within which the slug is produced. The well is also equipped with three (3) electric gas lift valves (EGLVs) that measure the temperature and pressure in both the tubing and casing at the various locations depicted in Figure 1. The main gas lift valve for the intermittent gas lift study is the pilot valve set at 1360 ft from the surface. A standing valve is set in the tubing below the pilot valve for reasons described later in this paper.

In addition, operators provided field data from a number of intermittent gas lift (IGL) wells located in the Permian Basin. The dataset comprised key operating and performance parameters, including downhole tubing pressure, surface casing pressure, flowline pressure, gas injection rate, and well test measurements. These field data were systematically analyzed to evaluate well behavior and identify operational trends, performance limitations, and practical insights relevant to IGL optimization. The analysis yielded several important lessons regarding field performance and system response under actual operating conditions. These lessons learned are incorporated into the present study and are discussed in detail to support the interpretation of results and the development of more effective IGL design and operational strategies.

Also, the Texas Tech Gas Lift Consortium IGL Design Model was employed in this study as a principal analytical tool (Mensah & Leggett, 2026). In the present work, the model was applied to examine how changes in fallback factor and liquid production rate influence two important operational parameters: lift gas injection rate and cycle frequency. This application enabled a systematic comparison of performance trends and provided deeper insight into the interactions among well productivity, fallback behavior, and lift gas requirements. The model results support the analysis and interpretation of the operational behavior of the intermittent gas lift systems considered in this study.

From a series of tests, field data analysis, and modeling applications, a few lessons were learnt from the study. The next section describes some of the lessons we have learnt so far, and some suggested solutions.

OPERATIONAL INSIGHTS FROM INTERMITTENT GAS LIFT TRIALS

Tubing Integrity Challenges

Tubing integrity is critical for the performance and efficiency of IGL because it is the main conduit for gas injection to produce the liquid slug. Any loss of integrity in the tubing alters the expected pressure profile in IGL, further affecting slug dynamics and causing numerous adverse effects. When the integrity of the tubing is compromised, the gas injected into the tubing when the gas lift valve opens will bypass the design injection point and short-circuit into the tubing without passing through the gas lift valve. This eliminates the pressure buildup needed to lift the liquid slug. The well then starts behaving like a CGL well. Once the well behaves like a CGL well, more gas than needed to produce will be injected into the tubing, leading to overconsumption of lift gas.

Also, when the gas short-circuits into the tubing, it increases the tubing pressure. This causes the gas lift valve to open at a pressure other than its design pressure; hence, it opens at the wrong time. This leads to inefficient and unpredictable IGL cycles, and the operator cannot efficiently optimize the well.

Despite the adverse effects of poor tubing integrity, wells still suffer from a hole in the tubing due to corrosion caused by sour gases in the formation. From a relatively small number of IGL wells in the Permian Basin, we observed that 20% of the wells have no leak, 20% have a small leak, and 60% have leaks that will prevent effective IGL operation. This further proves why tubing integrity is significant in operating IGL.

We proposed a method to assess the integrity of IGL wells using casing pressure buildup and the real-gas law, which is representative of the actual gas injection rate into the casing. Figure *2* shows the profile of the surface casing pressure, depicting the moment the gas lift valve opens and closes, as well as the casing pressure buildup. From the slope of the casing pressure buildup, the actual rate at which gas is being injected into the casing can be calculated from the real gas equation, as shown in Equation (1).

$$Q_{inj} = \frac{\left(\frac{\Delta P}{\Delta t}\right) V_{ann}}{Z_{avg} T_{avg}} \times \frac{T_{st}}{P_{st}} \times \frac{1440}{1000} \tag{1}$$

Q_{inj} = the gas injection rate into the casing (MSCFD)

$\frac{\Delta P}{\Delta t}$ = the casing pressure buildup rate (psi/min)

V_{ann} = the volume of the casing-tubing annulus (ft^3)

Z_{avg} = the average compressibility of the gas in the annulus

T_{avg} = the average temperature of the gas in the annulus (R)

T_{st} = the standard temperature (R)

P_{st} = the standard pressure (psia).

This method can be used for surveillance to assess the actual gas injection rate into the casing. If the gas injection rate reported by the gas injection meter exceeds the calculated value, it is likely there is a tubing leak.

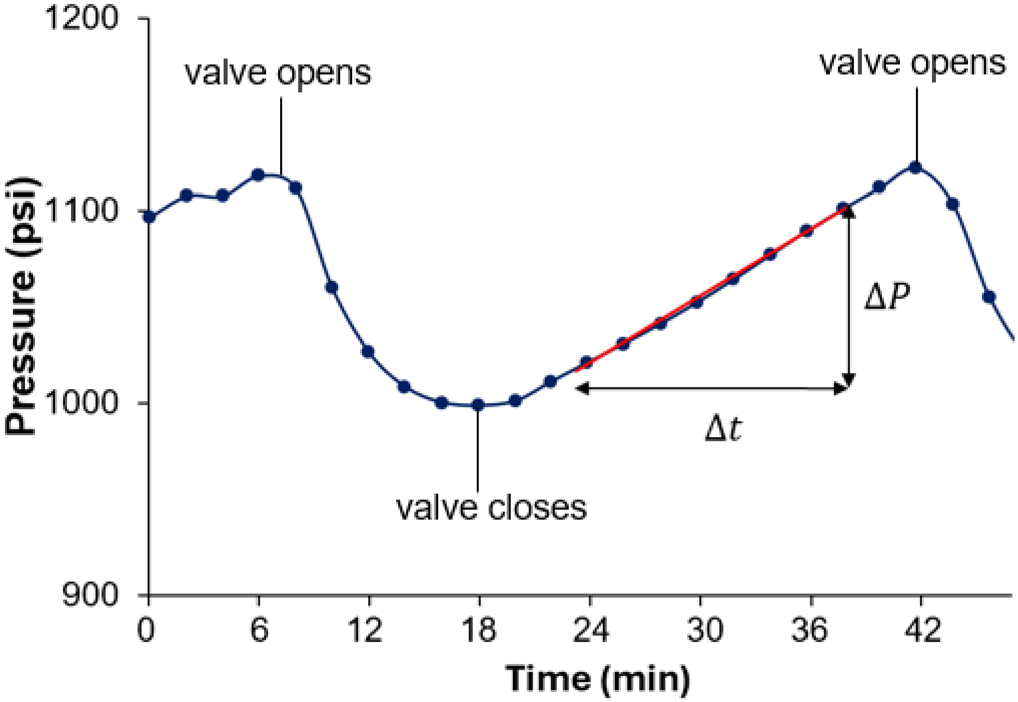

Figure 2: Surface casing pressure profile during gas injection, depicting the moment the gas lift valve opens and when the gas lift valve closes.

Considering Figure 2, the slope is 5.76 psi/min, for an annulus volume of 780 ft^3, average compressibility factor of 0.95, and average temperature of 143 ^{o}F, the gas injection rate can be calculated as follows:

$$Q_{inj} = \frac{\left(\frac{\Delta P}{\Delta t}\right) V_{ann}}{Z_{avg} T_{avg}} \times \frac{T_{st}}{P_{st}} \times \frac{1440}{1000}$$

$$Q_{inj} = \frac{(5.76 \text{ psi/min})(780 \text{ ft}^3)}{(0.95)(460+143)\ \ R} \times \frac{520 \text{ R}}{14.7 \text{ psia}} \times \frac{1440 \text{ min}}{1000 \text{ CF}}$$

$$Q_{inj} = 400 \text{ MSCFD}$$

To temporarily resolve tubing leak issues, other operators have used perforation sealers and tubing patches. These strategies will help temporarily fix the tubing leaks and efficiently utilize intermittent gas lift. Deferring workover operations can significantly increase the risk of requiring a fishing job. As tubing remains in service under corrosive well conditions, its structural integrity may deteriorate progressively over time. In such circumstances, an attempt to retrieve the tubing during a subsequent intervention can lead to mechanical failure, causing it to fall apart. This not only complicates the workover process but also increases operational risk and downtime.

Dependence of IGL Conversion on Well Conditions and Liquid Fallback Factor

According to Mantecon (1993), IGL is recommended when the well produces less than 100 BLPD. From our studies, we have observed that the time required to convert from continuous to intermittent gas lift cannot be based solely on production. It was observed that the well conditions, such as the tubing diameter, even affect the conversion time to IGL.

Liquid fallback is defined as the portion of the initial amount of liquid that remains unproduced (Hernandez et al., 1998; Mensah & Leggett, 2025). Studies have shown that the fallback factor depends on operational conditions, as these directly affect slug dynamics. In this study, we compared how the fallback factor affects the timing of conversion from continuous gas lift to IGL. The behavior of the required lift gas for a particular production with a varying fallback factor is shown in Figure 3.

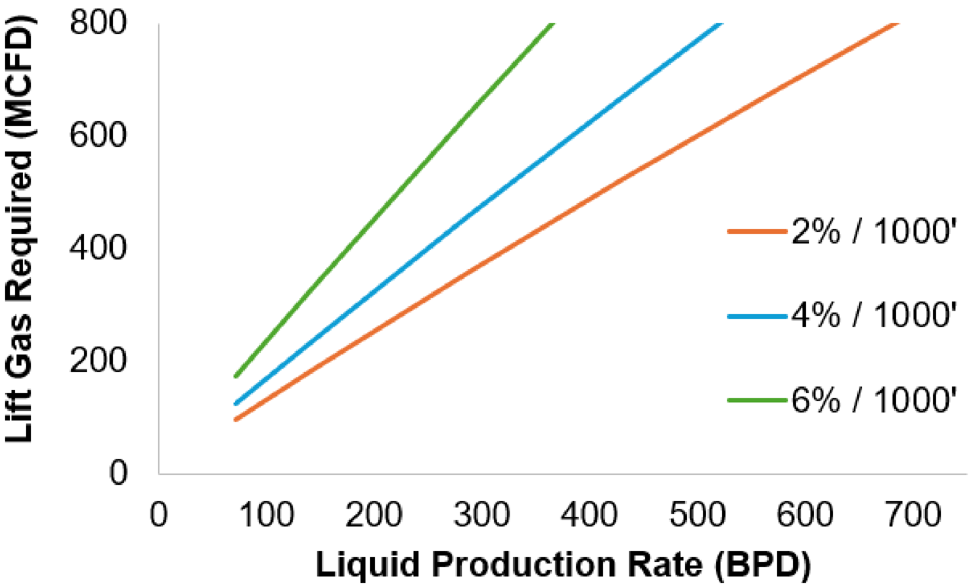

Figure 3: Impact of the fallback factor on the required lift gas for IGL for a well on continuous gas lift for 2-7/8-inch tubing.

From Figure 3, it can be observed that the amount of lift gas required for IGL increases as the fallback factor increases at a given production rate. One of the main goals of converting from continuous gas lift to IGL is to reduce lift gas consumption. From the plot, the lower the fallback factor, the less gas is required to produce at the same rate. This also shows the relevance of accurately knowing the fallback factor for a particular IGL well design. In summary, accurately knowing the fallback factor will help determine the optimal point at which to switch from continuous gas lift to IGL.

Performance Flaws in Standing Valves

As we have discussed, intermittent gas lift involves injecting high-pressure gas into the tubing to propel the liquid slug upwards to the surface when the gas lift valve opens. This high-pressure gas can exert backpressure on the reservoir, impeding the flow of reservoir fluids into the wellbore. For this reason, it is recommended to use a standing valve in intermittent gas lift. The standing valve should be located in the tubing below the gas lift valve to prevent high-pressure gas from affecting fluid flow into the wellbore. Aside from this effect, the standing valve also ensures efficient use of lift gas, so that all of it is used to propel the liquid slug upwards, thereby improving slug dynamics. When some of the lift gas escapes and flows back into the formation, it disrupts slug dynamics, leading to inefficient intermittent gas-lift operation.

Despite the importance of standing valves, their deployment can lead to leakage of lift gas past them. In wireline operations to set a standing valve, when the standing valve lands in the tubing seating nipple, the wireline operator applies an upward pull on the wireline. This breaks the shear, releasing the running tool and leaving the standing valve in place. The issue is that the shear pin can sometimes fall into the standing valve, preventing the ball from fully sealing. This causes lift gas to leak past the standing valve, resulting in inefficiencies in the intermittent gas lift cycle.

In the test well used for this study, described in the previous section, we have a standing valve set below the pilot valve used for intermittent gas lift tests. If the standing valve is sealing, the tubing pressure at the deepest electric gas lift valve, EGLV #3, should not increase when the pilot valve opens. Figure 4 shows the tubing pressures at the various points where the electric gas lift valves are located. From Figure 4, it can be observed that at the cycle where the tubing pressures were expanded, the tubing pressure at the location of the deepest electric gas lift valve increases. This increase in pressure confirms the leakage of the standing valve.

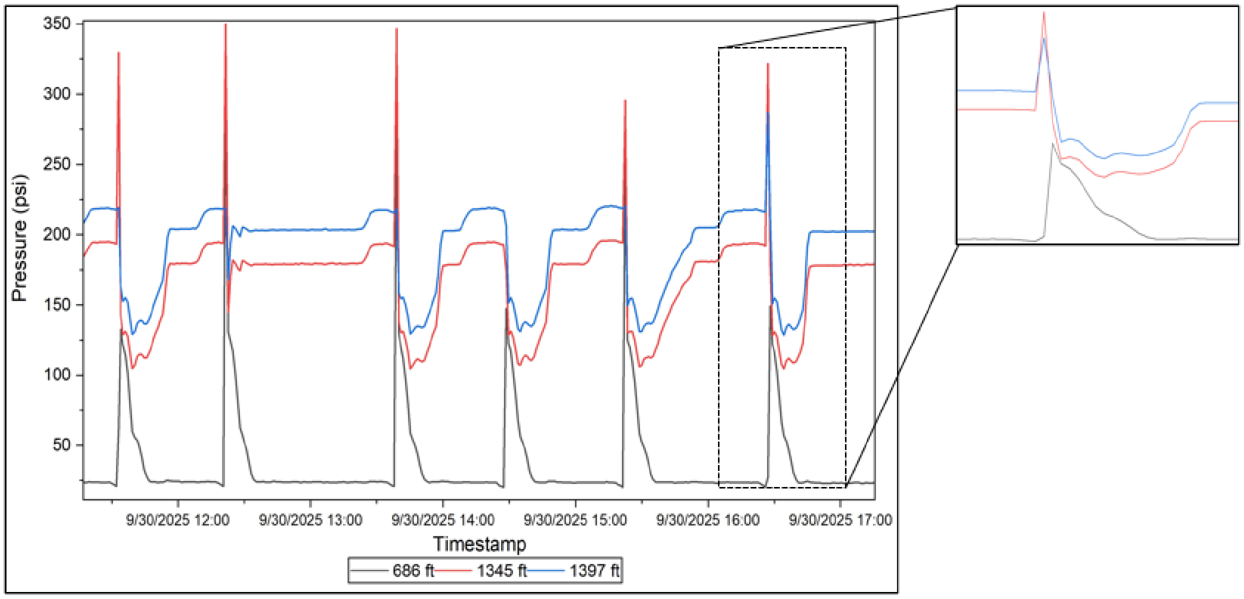

Figure 4: Tubing pressure profile measured at three points in the tubing, showing evidence of a leaking standing valve.

Figure 5(a) shows the shear pin that was discovered to cause a leak in our test well. From Figure 5(b), it can be seen how the shear pin occasionally prevents the ball of the standing valve from sealing on the seat.

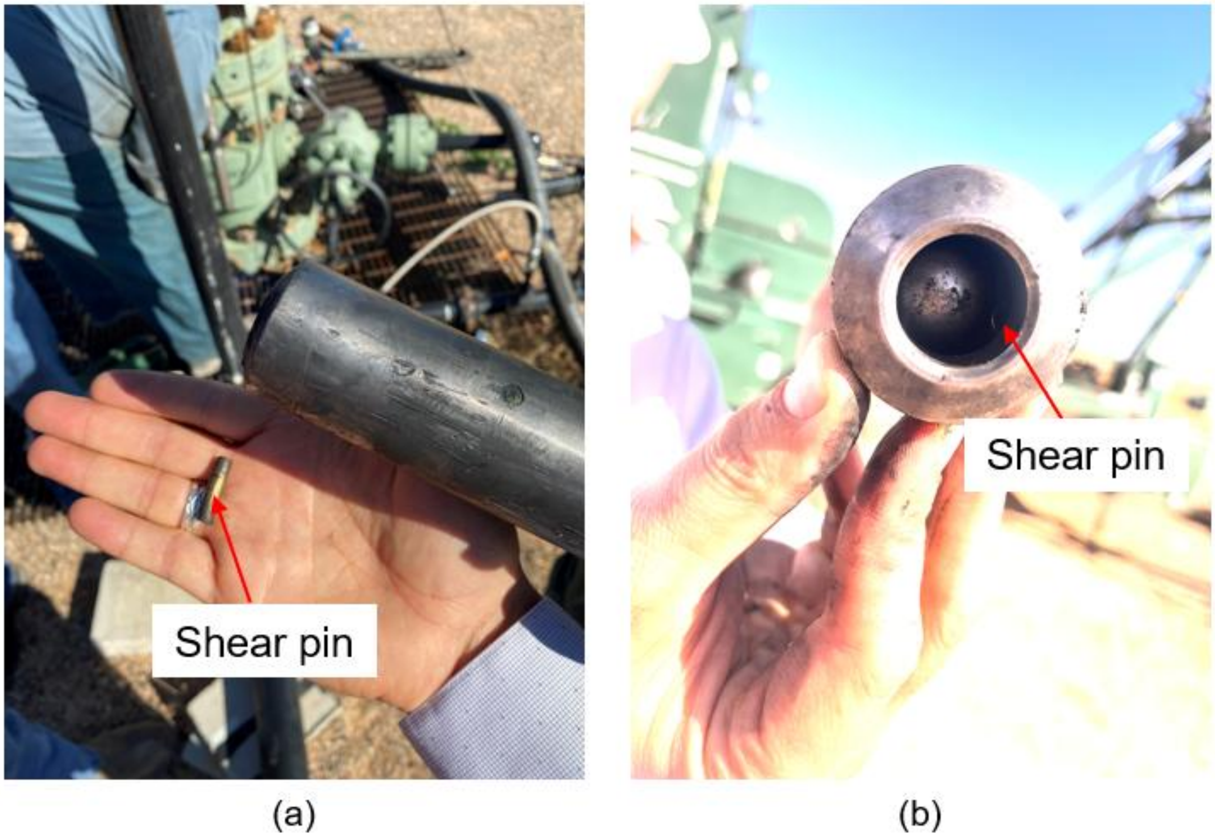

Figure 5: Picture of the shear pin discovered to cause leakage in the Red Raider #2 test well

These observations clearly show flaws in the deployment of a standing valve that can impede the efficacy of IGL operations. Wireline operators can work to improve the deployment of a standing valve to reduce this issue.

Consideration of Reservoir Depletion in Intermittent Gas Lift Design

As production continues, the reservoir pressure depletes, and in unconventional formations, this reservoir depletion is much quicker than in conventional formations. An IGL design must include a plan for the reservoir depletion because, as the reservoir depletes, the flowing bottomhole pressure also decreases. This results in a much lower tubing pressure at the gas lift valve location. Because the tubing pressure affects the valve opening pressure, the required valve opening pressure increases for the same valve as the tubing pressure decreases. This concept is known as the tubing effect. The tubing effect factor can be calculated using Equation (2) below.

$$\text{T.E.F} = \frac{R}{1\text{-}R} \tag{2}$$

R = port-bellows area ratio. It can be calculated using Equation (3).

$$R = \frac{A_p}{A_b} \tag{3}$$

A_p = Area of the port of the gas lift valve (in^2)

A_b = Area of the bellows of the gas lift valve (in^2)

From the valve force balance equation, the pressure required to open a closed valve is:

$$P_{cvo} = \frac{P_b}{1\text{-}R} + P_r' - \left(\frac{R}{1\text{-}R}\right) P_{tbg,v} \tag{4}$$

P_{cvo} = Valve opening pressure at the valve location (psig)

P_b = Bellows pressure (psig)

$P_{tbg,v}$ = Tubing pressure at the valve location (psig)

From the Equation (4), it can be observed that as the tubing pressure decreases, the valve opening pressure increases. In a situation where shallow valves are above the operating intermittent gas lift valve, a decrease in tubing pressure can cause them to open. This will lead to lifting from a shallow valve other than the actual valve for intermittent gas lift. This will lead to a situation similar to having a hole in the tubing as discussed in the previous section.

High-Frequency Monitoring Is Essential in Intermittent Gas Lift

IGL is a highly transient process (Brill et al., 1967; Hernandez et al., 1997). The behavior of the liquid slug can be easily understood by pressure sensors at the downhole and the surface (Hernandez et al., 1998). Due to the highly transient nature of the process, obtaining high-frequency data will help better understand the changes occurring in the tubing, and even when the liquid slug reaches the surface.

In the Figures Figure *6* and Figure *7*, a comparison is made between a 2-minute and a 10-minute sampling rate. It can be observed that several vital pieces of information are missed when monitoring data at a 10-minute sampling rate compared to a 2-minute sampling rate. From the observation in Figure 7, the moments the pilot valve opens and closes cannot be determined with reasonable accuracy. This shows the relevance of monitoring data at high frequency. It helps operators in surveillance and troubleshooting of the process. This shows the importance of having high-frequency data.

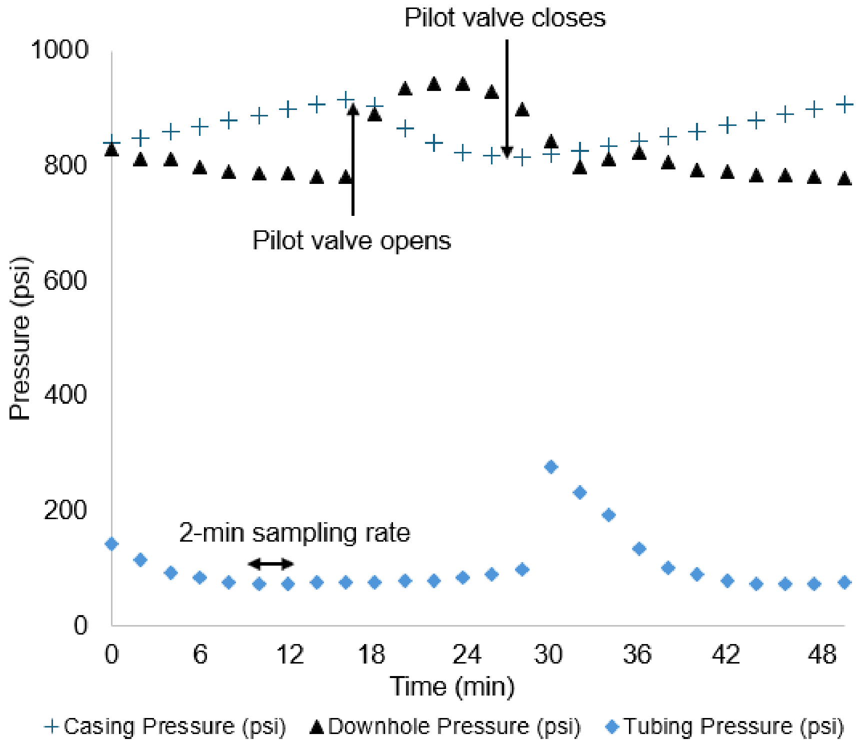

Figure 6: Intermittent gas lift pressure data with a 2-minute sampling rate, depicting the moment the pilot valve opens and closes.

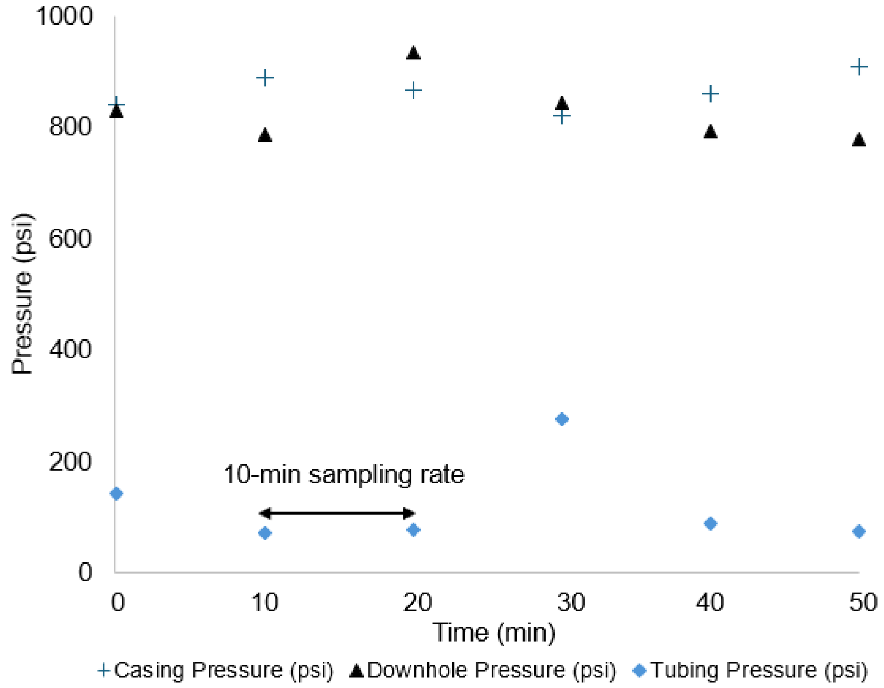

Figure 7: Intermittent gas lift pressure data with 10-minute sampling rate.

Operational Similarities Between Sucker Rod Pumping and Intermittent Gas Lift

From our study, we discovered some operational similarities between IGL and sucker rod pumping. Equation (5) describes the production rate in sucker rod pumping.

$$q_L = 0.1484 A_p S_p \eta N \tag{5}$$

q_L = Liquid production rate (BPD)

A_p = Area of pump plunger (in^2)

S_p = Pump stroke length (in)

η = Pump efficiency (fraction)

N = Pump speed (SPM)

A similar equation can be written for the production rate in intermittent gas lift, as shown in Equation (6).

$$q_L = 0.0012 A_{tbg} L_{slug} (1-F_b) N \tag{6}$$

q_L = Liquid production rate (BPD)

A_{tbg} = Area of tubing (in^2)

L_{slug} = Initial slug length (ft)

F_b = Fallback (fraction)

N = Cycle frequency (number of cycles per day)

From these Equations (5) and (6), the similarities between sucker rod pumping and intermittent gas lift are evident. For example, it is well known that increasing the plunger size of a sucker rod pump increases the liquid production rate, all else equal. The corresponding parameter for IGL is the tubing diameter. The following example shows that increasing the tubing size increases the liquid production rate capacity of an IGL system.

We conducted a sensitivity analysis on the effects of the tubing size on the required lift gas rate and cycle frequency using the Texas Tech Gas Lift Consortium IGL Design model. For this study, we considered a 2-7/8-inch and a 2-3/8-inch tubing. Figure *8* shows the behavior of the lift gas rate and the cycle frequency for this sensitivity study. From the plots, we observe that the cycle frequency is higher in the 2-3/8-inch tubing than in the 2-7/8-inch tubing, even though the lift gas rate is the same for the same production. This shows that converting to IGL depends on the tubing size being used as well.

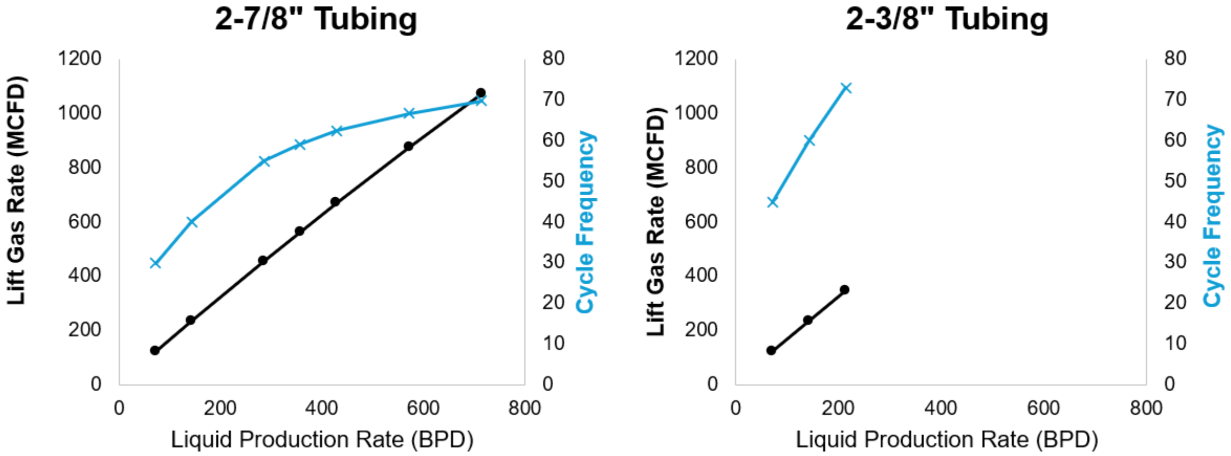

Figure 8: Comparison between the lift gas rate and the cycle frequency of a 2-7/8-inch and a 2-3/8-inch tubing, further confirming the similarities between sucker rod pumping and IGL.

From Figure 8, it can be observed that the number of cycles required to achieve the same production rate is higher in the 2-3/8-inch tubing than in the 2-7/8-inch tubing. A similar behavior is observed in sucker rod pumping, considering Equation (5). When the diameter of the plunger of the pump in sucker rod pumping is reduced, the pump speed must be increased to achieve the same production. This behavior further confirms the similarity between sucker rod and intermittent gas lift.

CONCLUSION

The results of this study indicate that intermittent gas lift (IGL) performance in late-life unconventional wells is controlled by many factors rather than by liquid production rate alone. Field observations and controlled testing show that tubing integrity is a first-order requirement for successful IGL, because any tubing leak alters the designed pressure buildup, causes gas short-circuiting into the tubing, shifts valve opening behavior, and increases injected gas demand. The study also demonstrates that conversion from continuous gas lift to IGL should not be based solely on production rate; it must also account for the fallback factor, tubing size, and gas lift valve depth, as these variables directly affect slug dynamics, cycle frequency, and gas utilization efficiency.

In addition, the work confirms that standing valve reliability is critical to cycle efficiency. Leakage past the standing valve reduces slug-driving efficiency and allows injected gas to dissipate into the formation, thereby degrading lift performance. The findings further show that reservoir depletion must be explicitly incorporated into the initial IGL design, because declining tubing pressure increases the required valve-opening pressure via the tubing-effect behavior and can unintentionally activate shallower valves, producing behavior analogous to tubing leakage. Finally, because IGL is inherently transient, high-frequency downhole and surface pressure measurements are required for diagnosis, surveillance, and optimization; lower-frequency measurements miss important cycle-level behavior needed to identify inefficiencies and tune operation.

Overall, these results provide a practical framework for improving IGL candidate selection, conversion timing, design, and long-term operation. By recognizing the importance of well-specific conditions and by treating IGL as a dynamic system requiring surveillance and adjustment, operators can improve liquid recovery, reduce inefficient gas usage, and increase the long-term reliability of intermittent gas lift in aging unconventional wells.

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