A NEW CONCEPT OF DOWNHOLE GAS SLUG MITIGATION IN UNCONVENTIONAL WELLS

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ABSTRACT

In wells where gas slugging occurs, fluid entering the gas separator can rapidly fluctuate from 97% liquid to 97% gas. During extremely high gas concentration periods, conventional gas separators struggle to process and deliver liquid to the pump. Investigation of this issue led to the development of a novel gas separator designed with internal liquid reservoirs that provide additional liquid for processing during a gas slug event.

This paper discusses a prototype gas separator's initial field trial results that replaced a conventional, high-flow tandem gas separator system. The well chosen for the field trial was drilled with an extreme “toe up” condition, which resulted in gas slugging soon after production started. Serious production interruptions started just above 1300 psi pump intake pressure (PIP) and led to premature failure of the electric submersible pump (ESP). These production difficulties motivated the customer, aware of the novel gas separator design, to conduct a field trial of the concept. The well was reinstalled with an identical ESP string, except for the original tandem Hydro-Helical Separator which was replaced with the prototype single Hydro-Helical Separator with extended length liquid reservoirs (referred to as the Hydro-Helical Slugger).

The results were encouraging. The new separator allowed drawdown below 1300 psi PIP with no production interruptions. As PIP neared 1100 psi, the duration and frequency of gas slugs increased, causing the variable speed drive (VSD) to operate in PID mode and eventually gas lock mode. Most importantly, the operator was able to continuously draw down the PIP over 400 psi while gas production increased 20%.

Following the successful initial trial, the concept was implemented in a steam-assisted gravity drainage (SAGD) well. The result was a substantial drop in motor load amperage fluctuations and significant increase in oil production.

BACKGROUND

Armis Artunoff [1] of Reda Pump, Bartlesville, Oklahoma, USA, developed and patented the first gas separator for use with ESPs in 1938 (US Patent #2,104,339). Since then, various technologies and methods have been invented to handle gassy downhole applications, including centrifuge chambers, open paddles, augers, vortexes, inverted shrouds, and tandem gas separators.[2,3] The mechanical separators were specifically engineered to function with a gas void fraction (GVF), representing the proportion of gas entrained in the liquid during processing and separation. A natural flow regime in vertical wells occurs where the liquid and gas phases intermingle as they enter the well bore and ascend within the casing.

Before the 1990s, most land wells were drilled vertically. More and more are now drilled horizontally, most notably in the unconventional shale gas plays. Horizontal wells have risen from about 9% of total wells drilled to over 50% in 2010. [4] In 2021, 81% of U.S. well completions were horizontal or directional, as opposed to 19% drilled vertically. (Figure 1) Horizontal and directional wells involve drilling a vertical well section and then, at a certain depth, bending the path of the wellbore away from vertical to drill a horizontal section. [5]

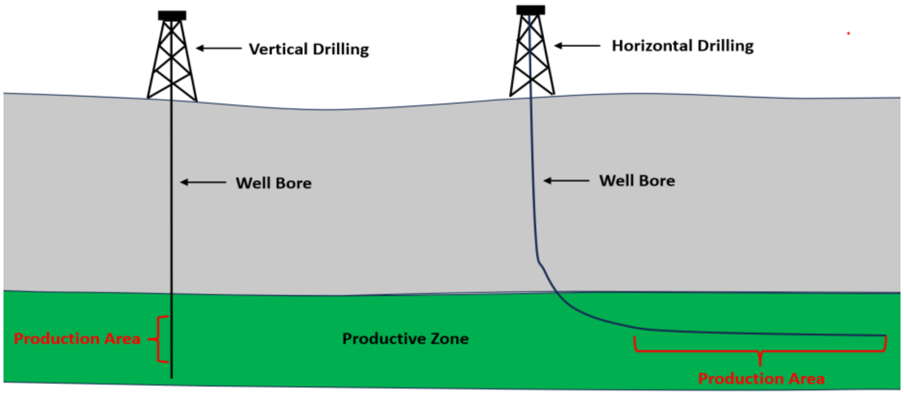

Figure 1 – Vertical well versus horizontal well through the production zone

Although the total number of crude oil and natural gas wells completed in the United States declined by 66% between 2010 and 2021, and total footage drilled has fallen by 30%, U.S. crude oil production has more than doubled, and U.S. gross withdrawals of natural gas have increased 55%.[4]

The hydrodynamics of a two-phase flow regime in unconventional, horizontal well bores is dramatically different than GVF-type flow in vertical wells due to the transition from horizontal to vertical. (Figure 2). Within the transition zone, the effect of gravity on liquid and the buoyancy of the gas results in a separation of the two phases, creating a slugging flow regime.

One of the significant advantages of horizontal wells is the increased contact between the well and the reservoir. The purpose of wellbore undulations, common in horizontal wells, is to increase the contact between the well and the reservoir and improve output. [6] The size and length of slugs vary with the formation output of the different phases and can be amplified with changes in inclination upstream of the transition from horizontal to vertical.

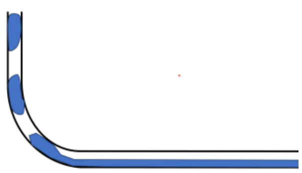

Figure 2 – Creation of slug flow at transition from horizontal to vertical

Slugging can be a significant challenge to the performance of rod pump and ESP systems. The alternating arrival of a liquid slug and a gas pocket makes separation difficult and causes significant gas entrainment, which can deteriorate pump performance. [7] In both forms of artificial lift, inverted shrouds have been used to mitigate the effect of slugging flow regimes. (Figure 3) However, in ESP systems, where larger diameter systems are required to handle the higher flow rates, the dimetric clearances usually disallow their use.

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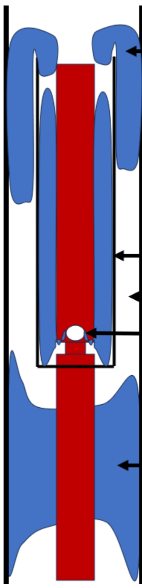

Figure 3 – Inverted shroud used to mitigate slug flow

DEVELOPMENT

Mechanical gas separators are designed to ingest multiphase fluid into a separation chamber where the phases are separated. The gas phase and any excess liquid are ejected into the well annulus. This process provides sufficient liquid to the pump for the designed production rate. Small incremental gas slugs can be ingested by the separator and processed with little interruption to the production pump's performance. However, in cases of extended length gas slugs, the gas separator runs out of liquid to process and deliver to the pump, resulting in reduced production, increased motor load amperage, and pump intake pressure swings.

In 2020, research began to understand the effect of gas slugging and develop a method to mitigate the negative impact on ESP and mechanical gas separation. The goal was to create a separation system to ingest extended gas slugs while maintaining enough liquid to be processed and delivered to the production pump. The system design should also require a minimum increase in horsepower.

To better understand the internal and external flow regimes of gas separators, a state-of-the-art, proprietary testing system was built utilizing transparent well bore casing and gas separator housing. (Figure 4) Varying gas slugs were introduced to the separator intake. Observations showed that as the length and duration of a gas slug increased, the separator struggled to maintain adequate liquid delivery to the pump. As the gas slug filled the separator, excess liquid expelled from the previous liquid slug would return to the intake and mix with the gas. However, this recycled liquid would deplete in seconds, allowing gas into the pump intake.

Figure 4 – Transparent test system

A novel idea that provided an extended internal reservoir below the separator chamber was evaluated. The intent was to increase the residence time of the liquid phase during a gas slug event and simultaneously create a liquid reservoir on the exterior of the separator between the separator's housing and the well bore. The latter concept would simulate the effect of an inverted shroud component.

This design allowed the separator to ingest longer duration gas slugs than a normal gas separator as the extended length, residence time and recirculation of liquid outside the separator mitigated the slugging effect. The test system does have some length restraints, but limited testing validated the concept. A field trial of the separator system with greater length, storage, and increased residence time was proposed.

The extended-length prototype was constructed with 13 separate internal reservoirs interspersed with fluid movers to provide shaft support, mix the fluids, and propel the fluids through the system. The downstream end was mounted to a high-performance single separator (Figure 5). The selection criteria for a field trial was a well experiencing issues or failure due to extreme gas slugging with a tandem high performance separator which would be replaced with the novel separator.

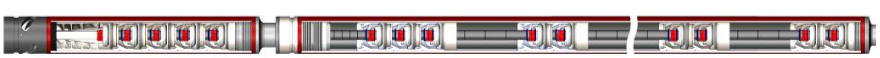

Figure 5 – Hydro-Helical Slugger™

FIELD TRIAL RESULTS AND DISCUSSION

A 400 series concept and prototype were presented to operators for consideration for any well meeting the selection criteria. A Permian basin drilled with a severed toe up condition was selected. A tandem high-performance separator was used in the initial installation and began experiencing gas slugs almost immediately after startup at about 1400 psi intake pressure. The slugs were so severe they caused extreme motor amperage swings and a broken shaft.

A single Hydro-Helical Slugger replaced the tandem separator for the second installation. Based on the previous production data, the pump's flow rate was also adjusted from 3500 BPD to 1750 BPD. As before, the drive was placed in PID (proportional integral derivative) control.

Initial operation of the system revealed improved performance by the single Hydro-Helical Slugger: motor current swings were reduced by over 60 percent, and intake pressure swings dropped by approximately the same amount (Figures 6 and 7).

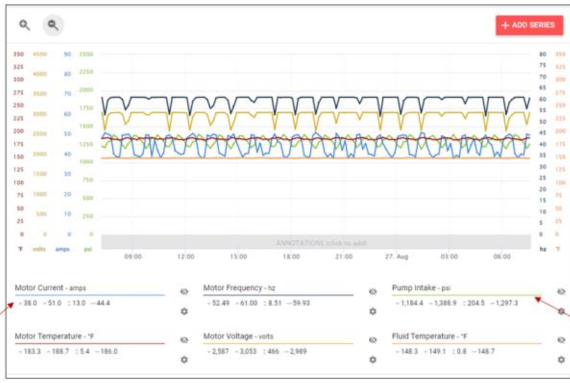

Figure 6 - Tandem Hydro-Helical Gas Separator performance in slugging conditions at approximately 1,300 PIP.

Figure 7 - Single Hydro-Helical Slugger Gas Separator performance in slugging conditions at approximately 1,200 PIP.

A review of the overall well operation (Figure 8) indicated the novel concept of the single Hydro-Helical Slugger offered superior operational benefit over a tandem separator of the same design without the extended-length liquid reservoirs. The system was able to operate below the bubble point with increasing gas slug length and duration, PIP was maintained at a lower value for the remainder of the run time, motor temperatures were significantly lower, and shutdowns due to slugging events were reduced by nearly half.

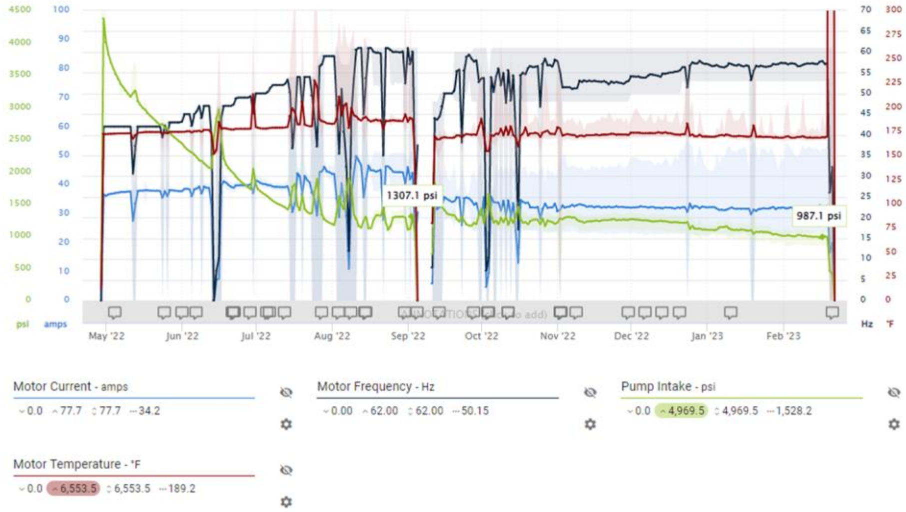

Figure 8 - Tandem Hydro-Helical Gas Separator operation (May through Sept), Single Hydro-Helical Slugger operation (Oct. through March).

After sharing the concept with other operators, a request was made to build a high-temperature 538 series system for the SAGD (Steam Assisted Gravity Drainage) market because traditional gas separators had proven ineffective. The application required the system to operate in a near-horizontal position, so a third component was added to the previous design, which positioned the system's intake on the bottom side of the casing (Figure 9). The first high-temperature prototype was installed in April of 2023, which replaced an existing unit without a separator.

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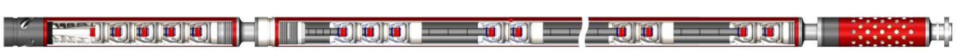

Figure 9 - High-temperature Hydro-Helical Separator Slugger with self-positioning bottom of casing intake.

As shown in the graph (Figure 10), the before and after installation of the separator system significantly reduced the motor amperage variations shown in yellow.

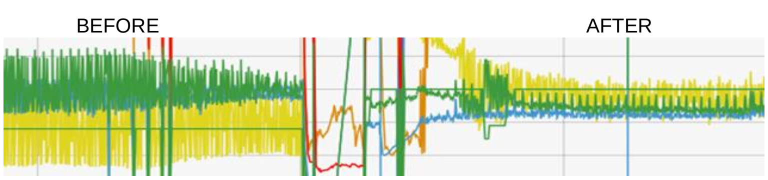

Figure 10 – Amp swings before and after Single Hydro-Helical Slugger installation.

<u>CONCLUSION</u>

Drilling technology has made great strides in the last 25 years, leading to increased production from subsurface formations. However, these improvements have changed the fluid flow characteristics, and slugging flow has become a major challenge for producers. ESP providers need to study and make design changes in their offerings to mitigate or ride through slugging flow regimes.

ESP engineers working with operators are beginning to understand the complexity of producing in unconventional, horizontal wells that experience severe gas slugging. Inverted shroud systems are effective but have limited usage due to diametric constraints and flow limitations. Traditional mechanical-style gas separators are limited in protecting the pump from gas slugs. The problem is compounded with reduced pressures as wells are drawn down and in wells drilled with toe up configurations and multiple undulations.

Test data from initial field trials suggest that creating an extended separator system with internal liquid reservoirs can mitigate gas slugging. Still, additional study is needed to understand future optimization opportunities better.

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