# BREAKING THE CURVE: IMPROVEMENT OF GAS SEPARATION EFFICIENCY FOR HIGH FLUID AND HIGH GLR HORIZONTAL WELLS

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## ABSTRACT

After deep analysis of gas separation methods and understanding the nature of fluid and gas flow, a new design is developed to generate better downhole conditions and enhance gas separation efficiency. A study of legacy downhole gas separators using a substantial database of horizontals wells across the Delaware and Midland Basins demonstrated a decrease in gas separation efficiency with an increase in GLRs and fluid rates. The development of this new methodology breaks the curve, not following the typical relationship of gas rates and gas separation efficiency. This has allowed for meeting and exceeding both rates and GLRs during ESP and Gas Lift to Rod Pump conversions in 5.5” casing, where annular space has previously limited gas separation efficiencies with legacy technology. This new design has an innovative technique to combat surges and homogenizing wellbore fluid to create maximum gas separation resulting in optimal well performance.

## INTRODUCTION AND PROBLEM DESCRIPTION

Permian Basin wells produce significant amounts of gas, causing several challenges on Rod Pumps, especially on wells converted from Electrical Submersible Pump (ESP) and Gas Lift with higher fluid rates. Developing methods to handle high gas volumes is crucial to ensure each well reaches its maximum potential, especially for those lifted by Sucker Rod pumps. Pumping wells with high gas to liquid ratios (GLRs) often leads to low pump fillages, ineffective production, and failure due to buckling, among other negative consequences, that ultimately lower the economics of a well. Multiple gas separator designs have been created and modified over time, seeking to solve gas interference challenges and significantly improve the value of our assets.

## OPERATOR’S PROGRESSION IMPROVING GAS SEPARATION EFFICIENCY

With a substantial set of horizontal wells across the Permian Basin, the operator has trialed many offerings of downhole gas separator technologies including, but not limited to, open top, slotted, multi-component, centrifugal, packer, and redundant separation separators. Figure 1 demonstrates how these legacy technologies have performed over time plotting the Total Fluid vs GLR for each well installation over a substantial subset of wells.

### Figure Calculation Methods and System Efficiency

The data represented in the proceeding figures cover a vast set of installations since 2021 across the whole Permian Basin in the operator’s portfolio of horizontal, rod pumped unconventional wells. Total fluid, GLR, pump fillage, and system efficiency of each system installation is calculated by using the average parameters between Day 14 and Day 90 post return to production. This period of production rules out the effects of flush production and evaluates a period of time during which the efficiency of a separator should be at its peak. A best fit exponential curve in solid is fit through the actuals data while a dashed line is plotted as the authors’ interpretation of observed maximums for each separation technique. Bubble sizes are represented as small and large, where small bubbles represent wells with average pump fillages less than

60%, large bubbles with pump fillages greater than 80%, and medium bubbles showing fillages between 60 and 80% over the same period.

System efficiency (SE) as demonstrated in Table 1 is calculated as follows with average values over the same period:

$$SE = \frac{WT}{(SPM * SL * D * C * RT)}$$

Where,
SE = System Efficiency (%)
WT = Average of Well Tests (BFPD)
SPM = Strokes per Minute
SL = Stroke Length (in)
D = Pump Diameter (in)
RT = Runtime (%)
C = Conversion Coefficient for Barrels per Day

Figure 1: Elevated GLRs Reduce Total Fluid Rate
Figure 1 demonstrates degrading fluid rates as GLRs increase over approximately 500 installs since 2021 utilizing a variety of downhole separators, rod designs, and pumping units at varying speeds. Later data demonstrates a vast improvement of fluid rates from conversion of legacy downhole separators to improved techniques noting that fluid rates have not been limited by well productivity but by separation efficiency.

Figure 2: Phase 1 – Pumping the Curve Improves Separation Efficiency but Yields Similar Relationship
The operator first tapped into gas separation improvement upon trialing concepts introduced by Dr. James Brill with 2 phase-flow in inclined pipe. "Based on the studies of by Brill et al, the liquid holdup is maximum for upward flow at angles between 40 deg and 60 deg from horizontal, so the pump assembly should be set in the section of the wellbore in which the inclination is in this range. The laboratory tests discussed earlier indicated that, at 45 deg wellbore inclination, the percentage of liquid entering the pump was greater than 95%" (Bommer & Podio, 2012). The operator landed pumps between 45 and 60 degrees in the curved portion of the horizontal well to test for separations efficiencies, production rates, and runtime among other factors. The size of the bubbles in Figure 2 validate improvement in gas handling, with most data showing acceptable fillages greater than 60%, more commonly being 80+%. While, on average, the operator exceeded previous fluid rates for varying GLRs, the best fit curve continues to yield a similar relationship where fluid produced from any given well drops for higher GLRs. More data needs to be collected for further explanation, but the relationship may be due to higher gas breakout in the tubing string after fluid entry through the pump. Table 1 demonstrates pumping in the curve resulting in the poorest system efficiencies for higher rates and GLRs, which may be due to added friction from the pumps and equipment in the curve. Ultimately, further tests and well configurations with rods and pumps in the curve are currently limited due to the rise in their failure frequency without significant incremental benefits to other gas handling techniques.

Figure 3: Phase 2 - Separator in Curve Yielded Positive Results with Less Risk
To further test in-curve fluid regime concepts, the operator installed a variety of separators (mostly close forms of poor-boy gas separator configurations) predominantly between 40 and 60 degrees of the horizontal wellbore. An improvement was observed vs legacy separators placed closer to the kick-off-point (KOP) of a well, noting an improvement of 15.87% in SE for comparable GLRs and fluid rates, showing the ability to lift similar conditions at lower polish rod velocities (Table 1).

Figure 4: Phase 3 – The Gas Release System Sets New Boundaries
While placing the separator in the curve of a horizontal well demonstrated promising performance, pump fillages degraded over time as gas volume fractions increased. Some wells observed consistent pump fillages and frequent dips where it was believed to be a gas bubble rising through the bottom-hole assembly (BHA) causing significant periods of low fillages. This led to the implementation of the Gas Release System (GRS), where a check valve is utilized in an engineered configuration to release gas from the internal diameter (ID) of the tubing into the annular space (Figure 5). While the best fit curve in Figure 4 is roughly in line with other separator types, the interpreted boundary curve is significantly outside the realms of prior

rates and GLRs established with legacy style separation, pumping the curve, and placing separators in the curve. Table 1 shows an improvement of 4.11% and 8.63% in SE and PF, respectively, while producing higher rates and GLRs on average vs placing the separator in the curve.

Figure 6 demonstrates one of the first case study wells, Gas Guzzler #1H. This well was converted from ESP to Rod Pump with the separation in curve configuration August 2022. The well went from producing ~300 BFPD and ~450 MCFD to ~435 BFPD and ~630 MCFD indicating improved performance over a degraded and inefficient ESP system. However, a rod part caused a short runtime failure, and a stuck pump gave the operator an opportunity to implement one of the first GRS installs. With no other changes besides the addition of the GRS, the well returned to production with ~530 BFPD and ~1,100 MCFD. Figure 7 plots the changes in load, speed in strokes per minute (SPM), and pump fillage trends pre and post conversion to GRS. Fillages improved on average, even with higher average SPMs, aligning with the increase in production observed after installation of the GRS. Over time, the well experienced a significant decline in fluid with an increasing GLR, so the well needed to be slowed to match the inflow of the well and optimize fillage and performance.

Figure 8: Phase 4: Re-engineered GRS Continues to Test other Variables

While the first version of the GRS breaks previous boundaries of gas separation, the operator partnered with a reputable oilfield technology company to further understand the variables that drive optimal performance. The partnership further engineered the GRS Version 2 (GRS v2), testing a variety of parameters. Figure 8 shows current performance with limited trials, demonstrating improvement with majority of bubbles showing favorable pump fillages. While the average system efficiency and fillage observed in Table 1 appear low, these represent limited tests for the fluid conditions represented by the table of data. More GRS v2 trials need to be conducted with high rate, high GLR wells.

## THE PHYSICS AND THE UNKOWNS

The configuration of the Separation BHA must first be explained in order to understand the possible physics of how gas may be escaping via the check valve in the GRS prior to entering the pump. As Figure 5 shows, the GRS is a secondary separation tool used in conjunction with a primary separator. Many types of separators may be used by the operator as the primary separator. Various derivatives of poor-boy separation have been found to be acceptable depending on well conditions. The primary separator has been generally placed at approximately 45º in the curve of a horizontal well. The purpose of the primary separator is to eliminate as much gas as possible from the fluid before the separated fluid migrates to the pump itself. The primary separator is placed at 45º to take advantage of a natural area of liquid holdup that commonly occurs in horizontal wells (Bommer & Podio, 2012). The fluid processed by the primary separator then theoretically contains significantly less gas by the time it works its way upward through the entirety of the lower portions of the Separation BHA to the secondary separator and then to the pump. There are, nevertheless, moments when some gas is able to travel up to the GRS. Gas migration into the GRS likely occurs for the following reasons:

1. Relative changes in hydrostatic-pressure-with-depth as fluid migrates from 45º in the horizontal to the depth of the seat nipple located above the KOP can allow for gas breakout.
2. Frictional losses from flow through the tailpipe section between the primary and secondary separator allow for gas breakout.
3. Extended periods of concentrated free gas flow in a dynamic flow environment capable of overwhelming the primary separator.

A common scenario that the Separator BHA will encounter is shown in Figure 9. But since there are situations where gas can essentially bypass the primary separator, there are moments when a secondary separator may be necessary to remove the additional gas to further improve pump performance. A plausible theory for when the GRS tool allows collected gas in the secondary separator to be released is presented below.

Gas Release Theory: Check Valve Opens During Liquid Surges

Gas naturally tends to collect in the upper portion of the Separation BHA due to gravity segregation of fluids. The collection of gas at the top of the GRS, coupled with fluctuating pressures and variable flow regimes within a well's casing, could result in periods where the total relative density of the fluid in the Separator BHA is less than the density of the fluid external to the Separation BHA. Figure 10 shows one such irregular moment of surging flowing bottomhole pressure that would cause the internal pressure of the GRS to exceed the external pressure, thereby allowing the check valve to open and release any trapped gas below the pump.

## PROBLEMS ENCOUNTERED

### Sand

While sand already poses a significant challenge for unconventional wells throughout the Permian Basin and beyond, the concepts presented throughout this paper resulted in further complications dealing with sand production. Previous systems, including ESPs, would generally be landed at or above the KOP of the well, so at lower rates during conversion, sand problems were less likely. The increase in fluid rates as high as 750 BFPD has brought an onslaught of sand, due to instantaneous rates being twice as high, increased velocities from essentially having a velocity string downhole, and ultimately setting the BHA closer to the horizontal portion of the well. Figure 11 shows the "Super Sandy #2H" example well converted from ESP to Rod Pump equipped with the GRS. Poor rates throughout the beginning of March 2023 were a result of "sand interference," where the BHA was suspected to be plugged with sand. A high rate flush with surfactant was conducted down the casing, and the well performed as expected after March (Figure 12). Sand continues to be an issue, and the operator is trialing various methods of dealing with sand, including varying screen sizes and desander technology.

### Well Inflow Limits

No separator can perform effectively when the outflow of the well exceeds its inflow. Over time, poor fillages and system efficiencies observed with legacy downhole gas separators caused the operator to overdesign rod lift systems to compensate. Understandably, many wells continue to be overdesigned to mitigate any unforeseen underperformance. However, this has led to poor system efficiencies simply caused by outrunning the inflow of the well. Figure 7 demonstrates a positive and consistent improvement in fillages and loads upon slowing down the "Gas Guzzler #1H." Even though it was slowed down, production in Figure 6 shows no step change, indicating the ability of the GRS to force unconventional wells to act more conventionally, being able to slow down wells, improve pump fillages, and maintain production.

## SUMMARY AND FUTURE WORK

As the data shows, installing GRS can significantly improve production performance of a horizontal rod pumped well. Pump speed adjustments are able to be made to match well inflow performance and improve pump fillages, which can improve rod pump equipment longevity. Additionally, smaller pumping units are now able to be utilized in place of larger pumping units to achieve comparable production rates.

While the current GRS configuration is effective for gas separation, progress is still being made to mitigate the negative impact of sand on production performance. One method for sand remediation is surfactant flushes, which have provided temporary benefit when "sand interference" occurs. Various sand screen configurations have been installed to help improve the separator's performance on a more consistent basis when large quantities of sand production occur.

Future steps to better understand GRS performance have been planned. Bottomhole pressure gauges at various points along the Separation BHA will be run to validate theoretical performance of the GRS and further optimize the wellbore configuration. Backside flow rate measurements are also underway to further explain the benefits of GRS utilization.

## REFERENCES

Bommer, P. M., & Podio, A. L. (2012). *The beam lift handbook*. Petroleum Extension Service, Continuing and Innovative Education, University of Texas at Austin.

**TABLE 1: SEPARATOR PERFORMANCE WITH WELLS PRODUCING > 300 BFPD AND >1000 GLRS**

| Wells >300 BFPD and GLRs >1000 | | | | | |
|---|---|---|---|---|---|
| Separator Category | Avg System Efficiency | Count | Avg PF | Avg GLR | Avg BFPD |
| GRS V1 | 76% | 36 | 78.53 | 1,852 | 409 |
| Sep in Curve | 73% | 18 | 72.29 | 1,397 | 388 |
| GRS V2 | 70% | 3 | 68.69 | 1,290 | 475 |
| Legacy | 63% | 23 | 72.32 | 1,329 | 388 |
| Pump in Curve | 61% | 3 | 83.83 | 1,286 | 384 |

Max Min

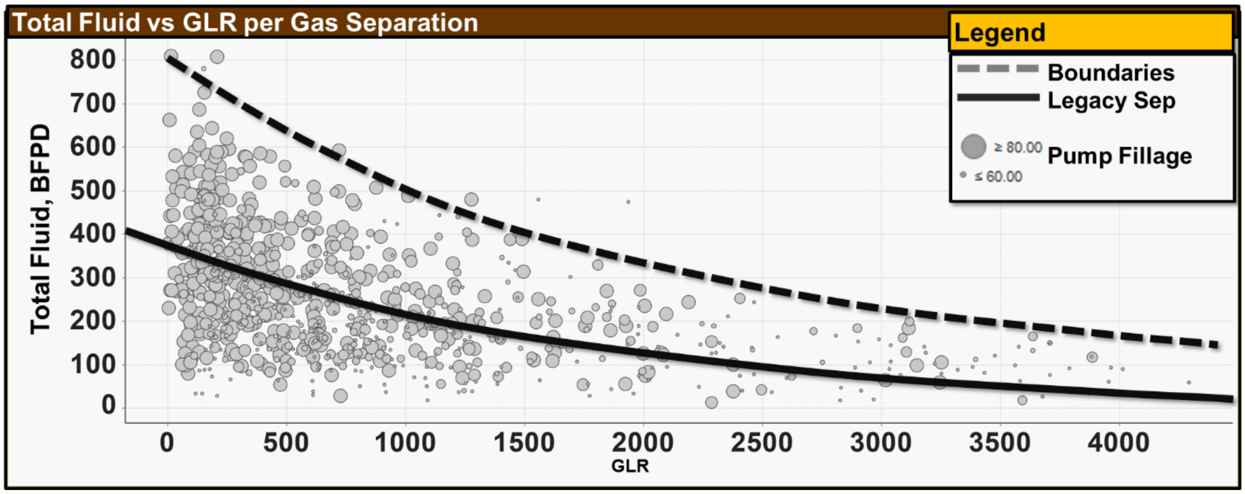


**Figure 1: Legacy downhole gas separator technology installed at or close to kick-off-point with various rod string designs, pumping units, and bottom-hole-assembly configurations.**

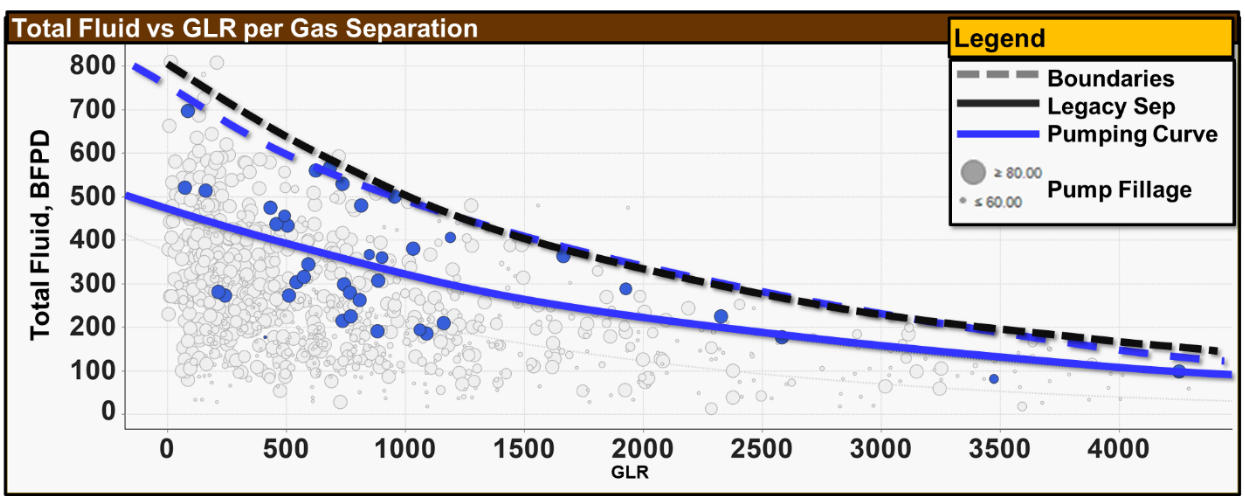


**Figure 2: Wells with pumps installed within 45 and 60 deg of the curved section.**

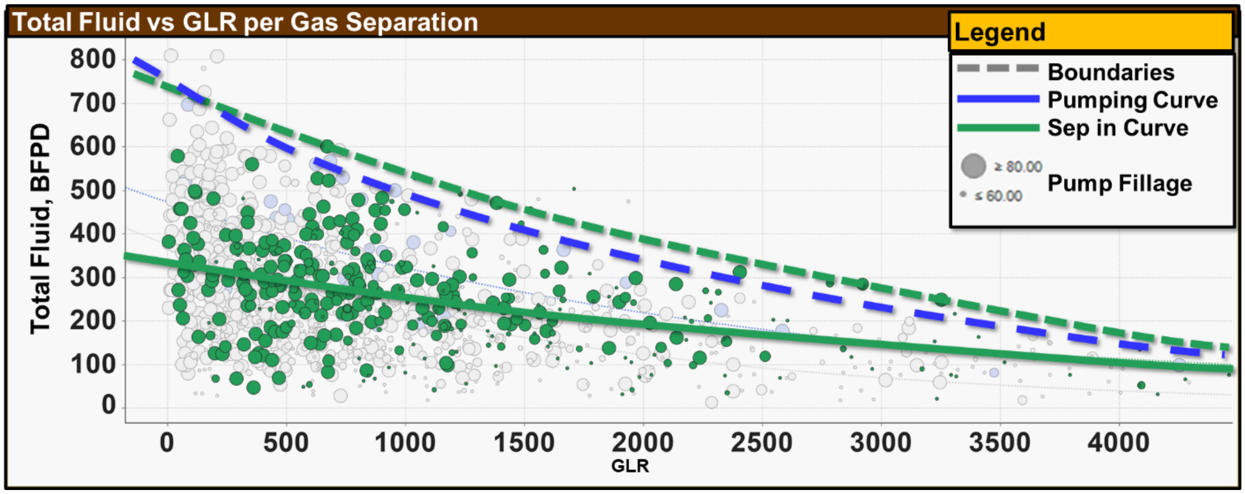


**Figure 3: Wells with separators and intakes (majority poor-boy type) installed within 45 and 60 deg in curve with pumps at or above the kick-off-point.**

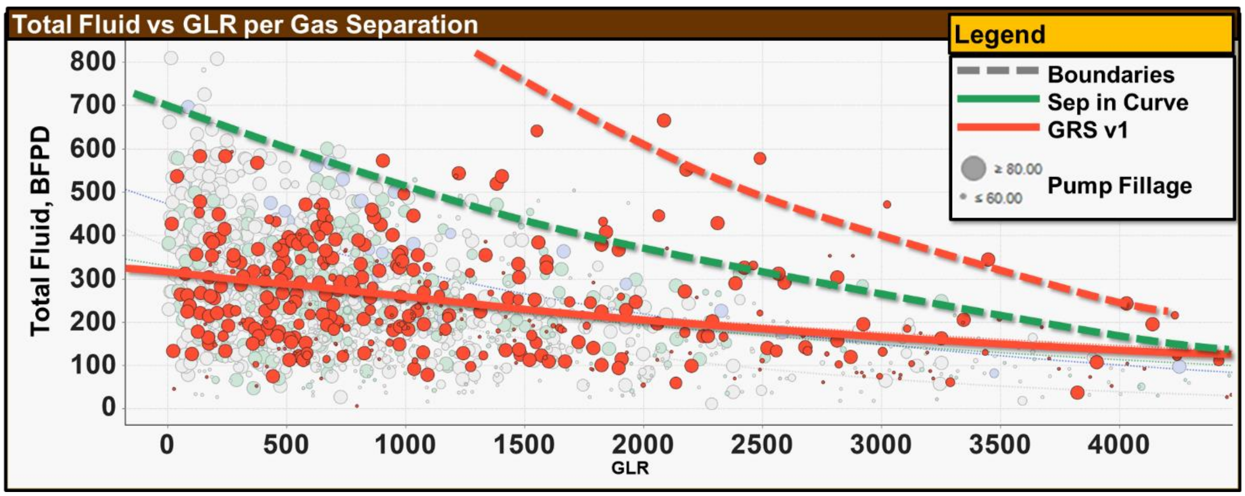


**Figure 4: Wells with separators and intakes (majority poor-boy type) installed within 45 and 60 deg in curve with pumps at or above the kick-off-point and utilization of the GRS (v1) below the SN.**

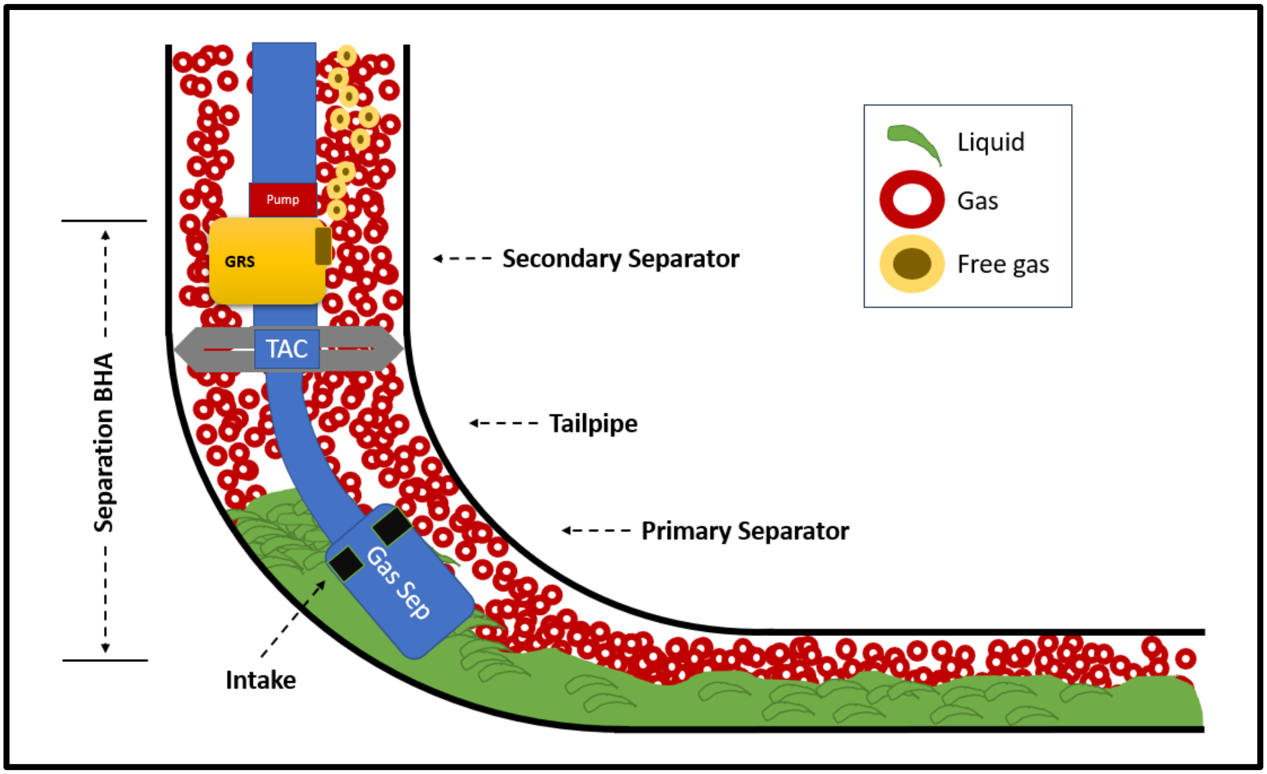


**Figure 5: The Separation BHA includes a primary separator and a secondary separator. The primary separator is set between 45 and 60 deg in the curve of the horizontal. The GRS is set above the TAC and KOP, but below the rod pump. The primary separator separates gas. The separated fluid then travels up the tailpipe to the GRS.**

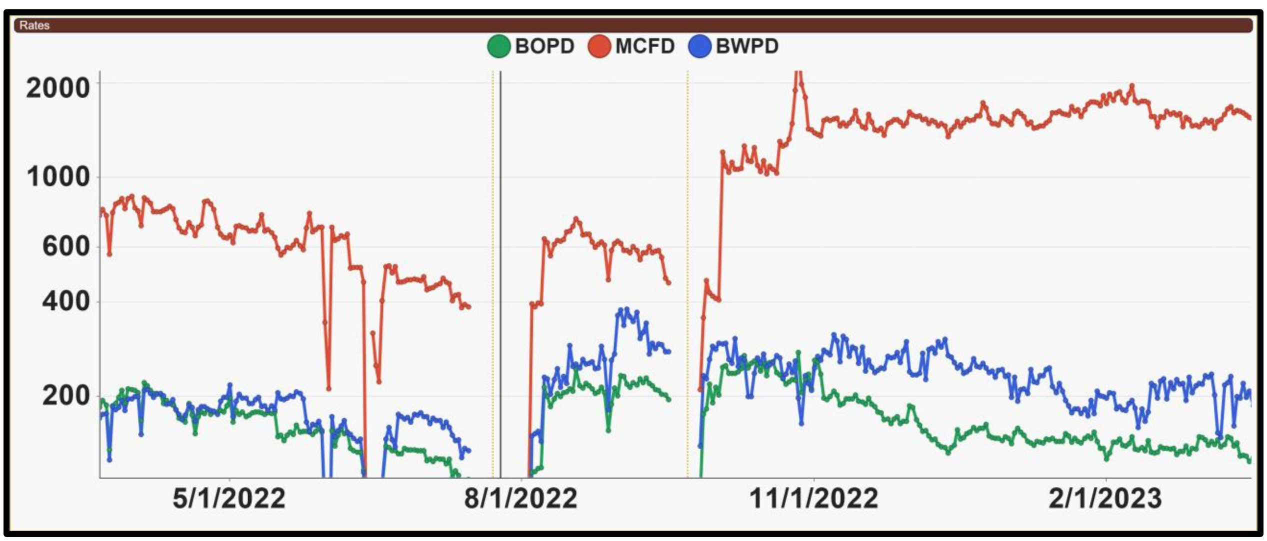


**Figure 6: "Gas Guzzler #1H" example well is converted from ESP to RP with separator in curve only assembly August 2022. The well fails sometime in September 2022 and the only change made is the addition of the Gas Release System (GRS).**

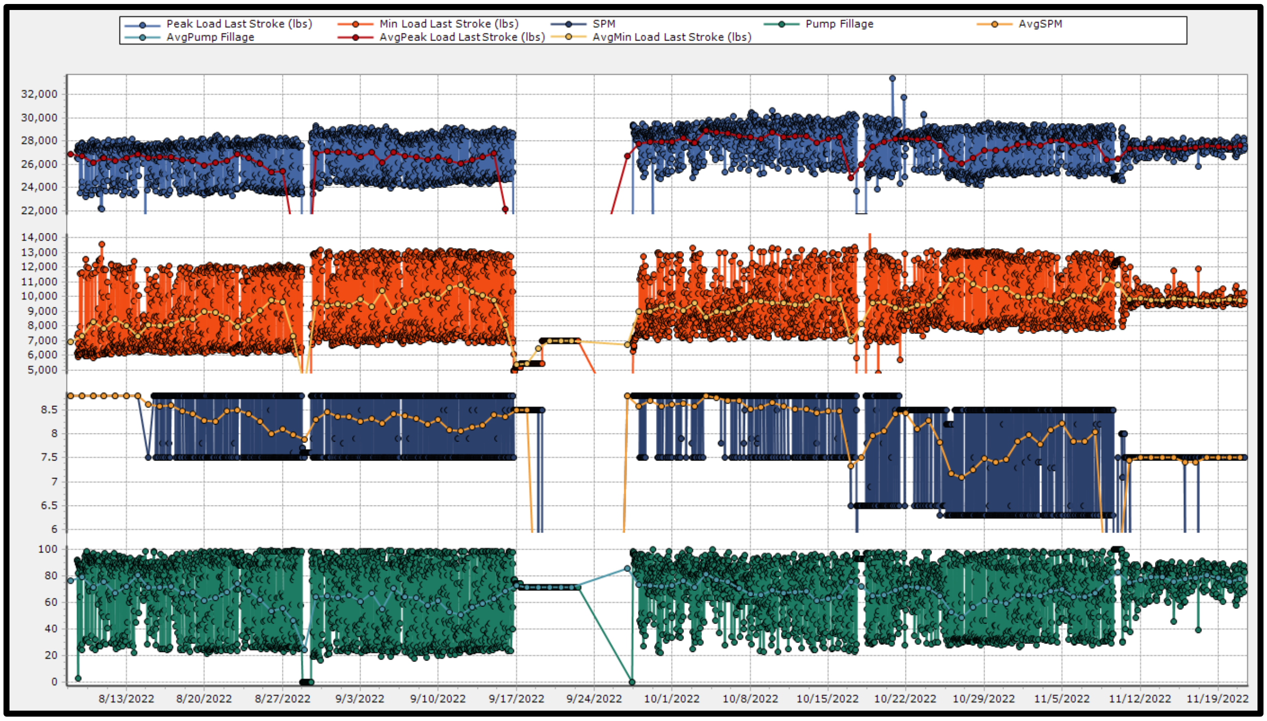


**Figure 7: "Gas Guzzler #1H" example well load, SPM, and pump fillage trends with averages displayed. With declining well production, the system is slowed down between October and November 2022, demonstrating conventional-like behavior to improve pump fillage without impacting production.**

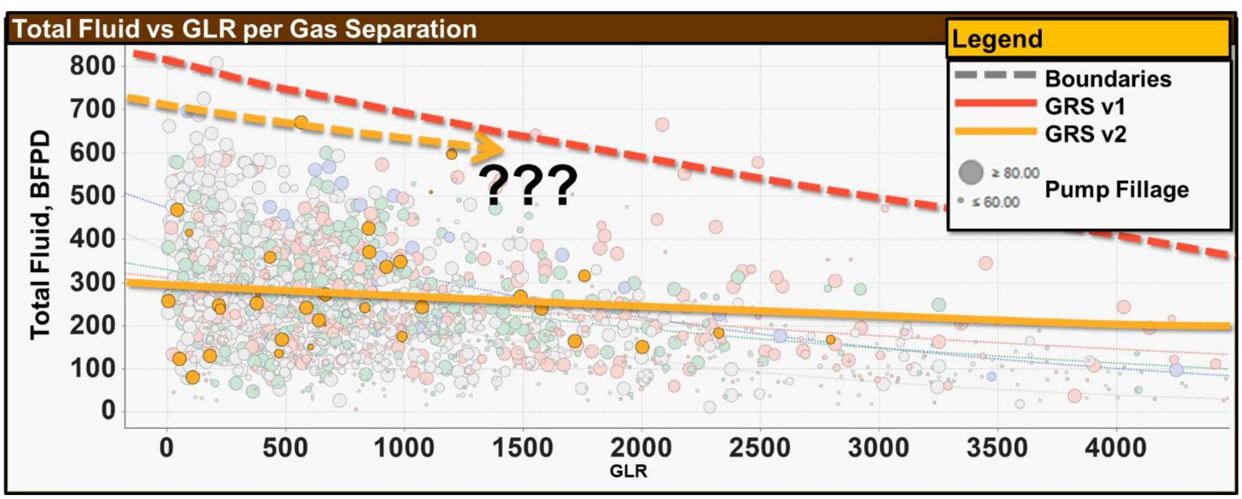


**Figure 8: The re-engineered GRS v2 demonstrates highly consistent pump fillages over a wide range of GLRs and fluid rates. Boundaries remain to be tested while the operator continues to gather data.**

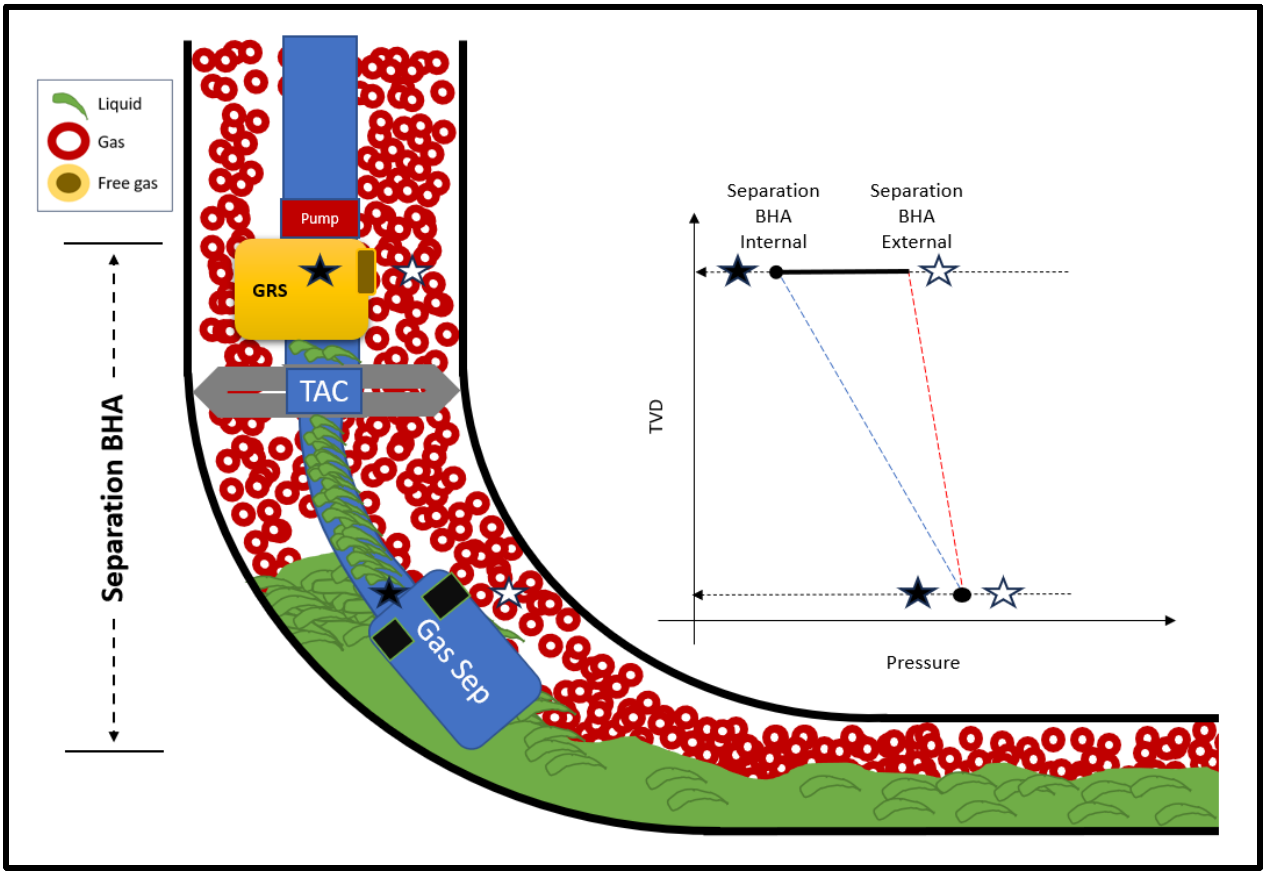


**Figure 9: Scenario for a gassy backside fluid gradient with a liquid internal fluid gradient. In this situation, the check valve will remain closed because the pressure external to the GRS exceeds the internal pressure of the GRS.**

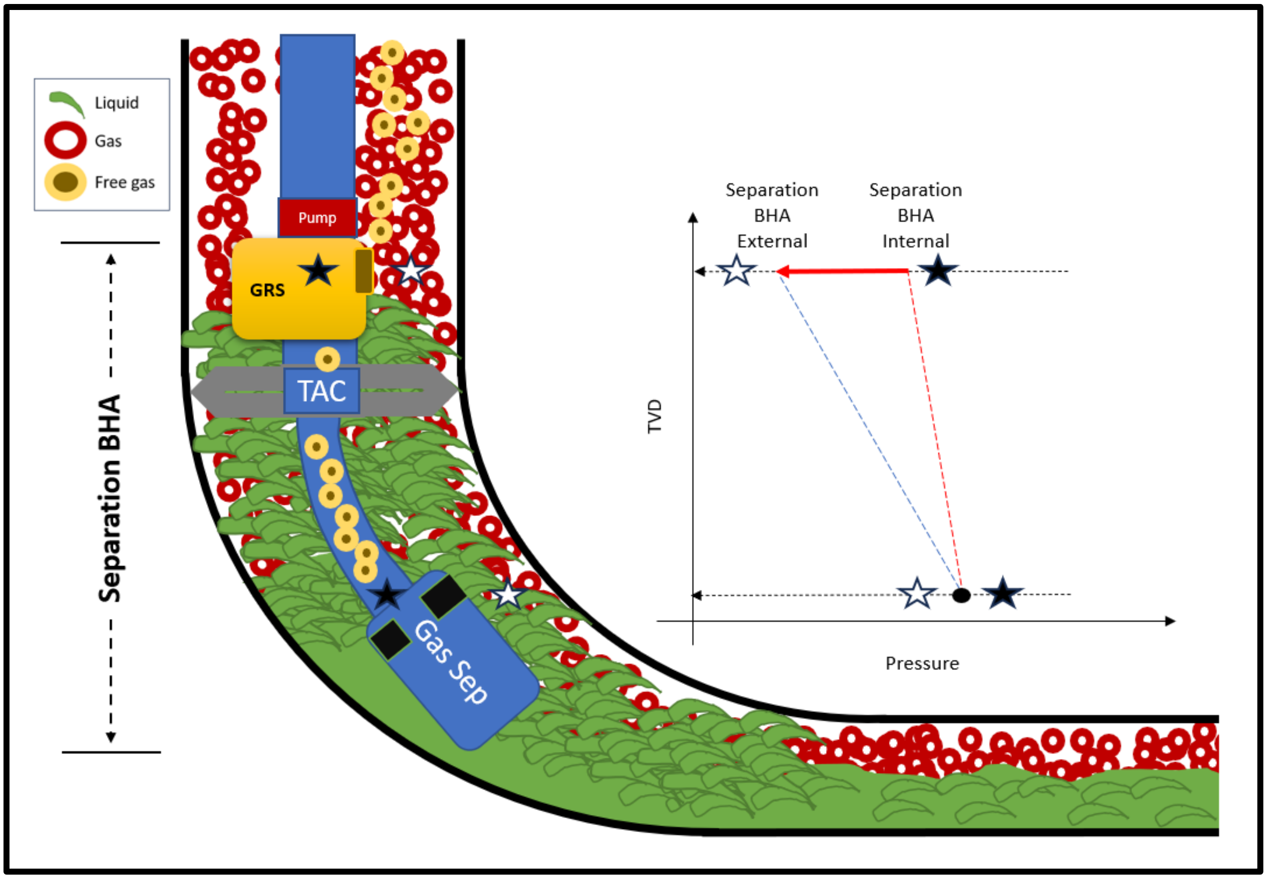


**Figure 10: Scenario for a gassy fluid gradient internal to the Separation BHA with an external liquid fluid gradient. In this situation, the check valve will open because the pressure internal to the GRS exceeds the external pressure to the GRS.**

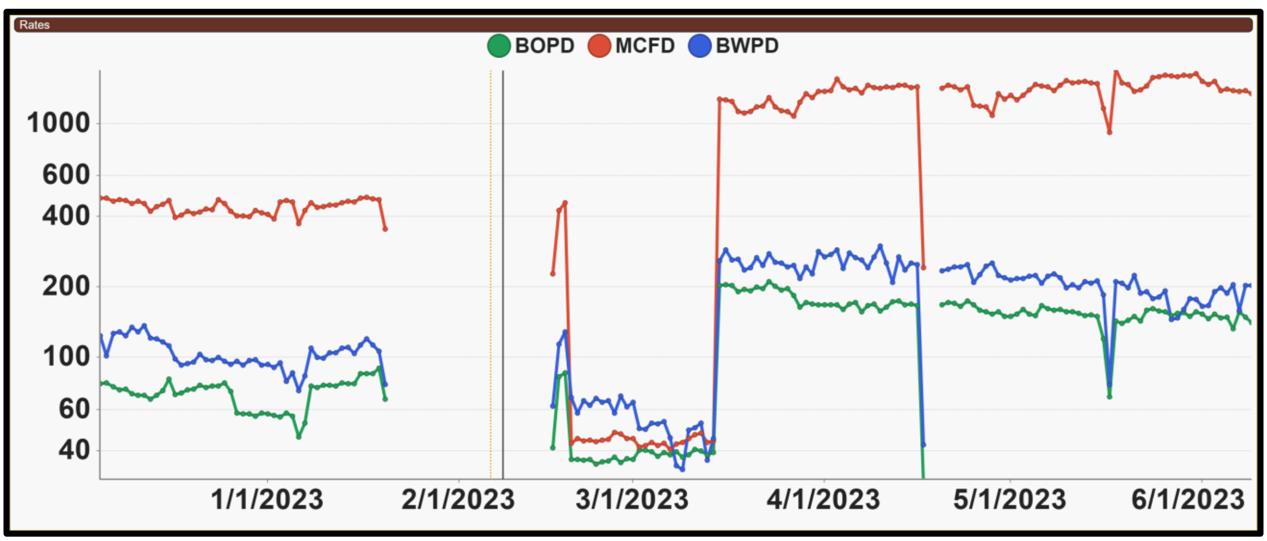


**Figure 11: "Super Sandy #2H" example well is converted from ESP to Rod Pump February 2023 and experiences poor performance due to suspected sand interference. A high rate surfactant flush is conducted via the casing and the well produces as expected.**

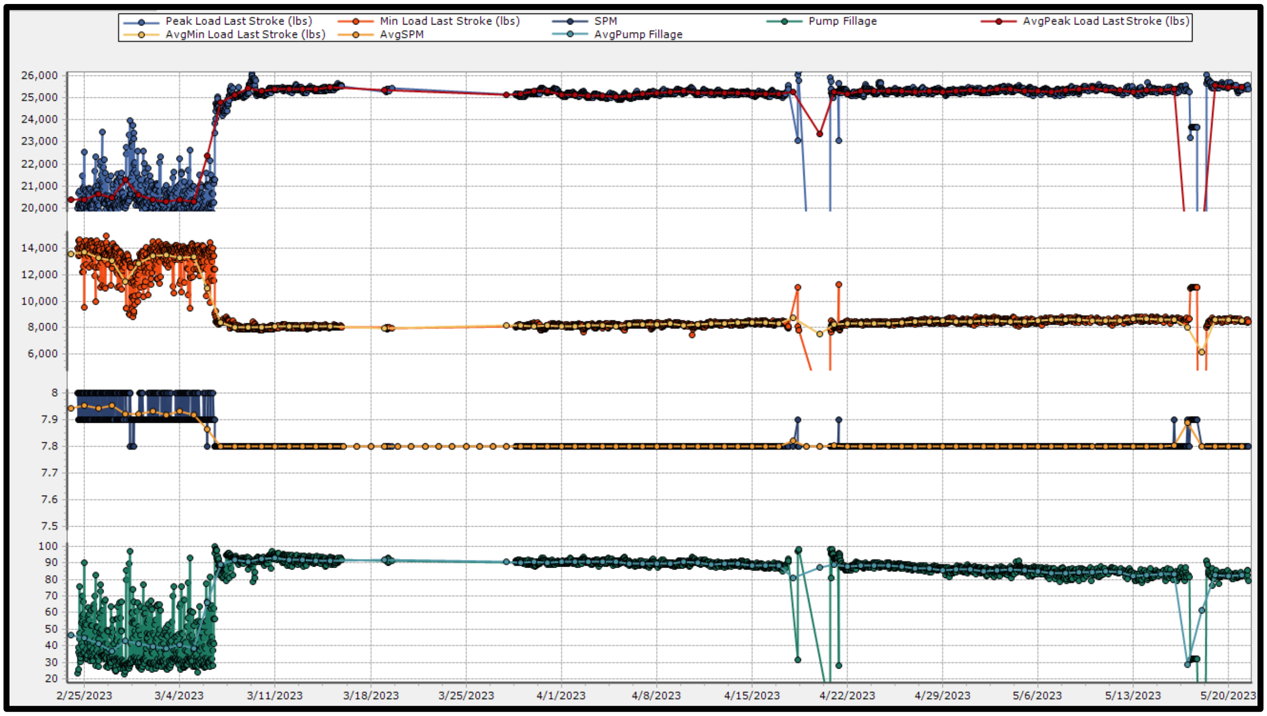


**Figure 12: "Super Sandy #2H" example well load, SPM, and pump fillage trends with averages displayed.**