CENESIS PHASE SYSTEM FOR HIGH GAS ESP APPLICATIONS

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ABSTRACT

Electric Submersible Pumps (ESPs) are severely affected by free gas entering the pump, which cause significant degradation in pump performance, due to gas locking conditions cause by bubbles blocking the fluid from passing through the impellers, resulting in frequent shutdowns and restarts, which increase the risk of early failure. This effect is even worst when a gas slug event, very common in horizontal wells drilled in unconventional reservoirs, hit the system, this event consists of a large volume of light density fluid (gas) flowing through the system, overheating the motor and pumps due to a no liquid flow condition, resulting in unstable production due to ESP shutdowns caused by underload or high motor temperature. The industry has used shrouds, rotary and vortex gas separators, and more recently, multiphase pumps to handle the gas, however, there are some applications where this equipment is not enough to handle the Gas Liquid Ratio (GLR). Recently two Oil Operator Companies in the Permian Basin following our recommendation successfully installed a Multiphase Encapsulated Production solution technology to separate the gas from the liquid in the wellbore. As produced fluids, pass the pump at high velocity, the heavier liquid falls back into the shroud in a low-velocity area between the tubing and the top of the shroud, allowing the gas to continue to the surface. This system has proven to separate the gas from the liquid effectively (> 90% of efficiency), stabilizing operations within a certain operating window. In this document, results are shown for two successful field cases, how uptime improved, being able to reduce the number of shutdowns, improving operational performance and increase the drawdown maintaining stable production of the wells.

MULTIPHASE ENCAPSULATED SYSTEM

Over the years, many different completion styles have been used to manage high GLR ESP wells (see Figure 1). Each completion system is dependent on several factors decided early on by the drilling and completion team that could limit the options for ESP gas management. Wellbore casing size, formation completion style, and vertical, horizontal, deviated trajectory all impact the type of gas management system can be employed. There are three basic goals when dealing with high-GLR wells: avoid the gas, separate the gas, and handle the gas. Early gas management included standard gas separators and gas handling stages. High-GLR wells can quickly exceed the volume limits of those tools and cause loss of flow, controller shutdowns, and potential failures. Gas avoidance is clearly the best solution for operating ESPs in high-GLR wells, and many different completions options have been developed. Gas avoidance uses the density difference between the gas and liquid to separate the two phases naturally. The most common method of gas avoidance is a shrouded ESP system set below the perforations with an open-ended pipe placed around the ESP equipment to force fluid below the motor through the inside of the shroud before it enters the pump intake. Similar to the shrouded ESP, a long dip tube pipe connects to the bottom of the shroud assembly to allow the pipe to sit below the perforations instead of the ESP assembly. This system is used to allow more annular area for separation, or in cases where the wellbore below the perforations does not have enough space for the ESP assembly. If the wellbore has adequate room below the perforations in the rat hole, a recirculation system can be used. Since there is no natural flow passing the motor, a small recirculation pump and capillary line is used to bypass some of the flow below the motor for cooling purposes. Finally, an inverted shroud assembly places an open-ended pipe above the ESP pump, forcing the fluid to go past the equipment and fall back into the shroud before entering the pump intake.

The Multiphase Encapsulated production solution (see Figure 1-right) has been proven in unconventional reservoir completions. This completion design was developed to overcome the gas slugging issues that many long horizontal wells experience. Standard gas handling ESP systems for these wells consist of a multistage primary lift pump, gas handling stages with split vanes and larger balance holes, a vortex gas separator, seals, a motor, and a sensor. Many of these completions had problems with the slugging cycles due to the sudden loss of load and the poor cooling ability of the gas as it passes by the motor. Initial trials of inverted shroud assemblies showed positive results in reducing the gas volumes through the pump, but they still experienced motor temperature shutdowns due to the cooling issues. The Multiphase Encapsulated production solution was a significant improvement because it eliminated the initial fluid flow past the motor while still helping from the natural separation. The Multiphase Encapsulated production solution combines the benefits of an inverted shroud system with a recirculation system to create a unique gas avoidance and handling option. The system works by allowing reservoir fluids, including the gas, to flow up the annular space outside the encapsulated ESP. Above the ESP, the fluid velocity is reduced due to the rapid increase in cross-sectional area from annulus to full-diameter production tubing. The heavier liquid falls by gravity (blue arrows in Figure 1-right), entering the inside of the encapsulated system and traveling down to the pump intake. To provide adequate motor cooling, some of the fluid in the pump is recirculated through a dedicated capillary line to the bottom of the assembly (yellow arrows in Figure 1-right) and flow pass the motor back to the pump intake.

For gas separation purposes, the fluid velocity needs to be as slow as possible. This may be counter intuitive to the goal of increasing production but increasing the fluid velocity above certain values reduces gas separation effectiveness. As the velocity increases, the upward buoyancy of the gas is overwhelmed by the boundary layer friction between the liquid and gas, which is a force in the downward direction. As shown in Figure 2, velocities above 1 ft/s reduce the phase separation, which leads to more gas in pump and results in underload conditions and gas locking. The downward velocity limit includes both the liquid volume and the gas volume at that pressure. As GLR decreases, the system can handle larger liquid rates, and vice versa.

PERMIAN BASIN CASE OF STUDIES

Permian Basin unconventional reservoirs are an especial challenging environment for ESP system performance, due to the high amount of gas produced when the well has declined in production and pressure, especially on those where enhanced oil recovery using CO2 is applied. The free gas leads to pump locking and system shutdowns, reducing system reliability and causing production loss, which negatively affects well economics. To improve ESP system reliability and enhance drawdown and production, Multiphase Encapsulated systems were introduced in two main Oil Operator Companies in the Permian Basin, such systems have been installed and ESP performance has improved, with very few shutdowns due to gas interference and significant improvement in drawdown. From Operator #1, the well #1 original production initiated in August 2017 and describes a typical production chart from an unconventional reservoir (see Figure 3), where the liquid production declines very quick, just a couple of months after activation, while gas production remains steady or even increase while pump intake pressure declines, causing a considerable increase on the Gas Liquid Ration that affects ESP performance.

The first ESP installed in this well was a high flowrate mixed flow stage design pump (Flex31) with just a gas handler pump at the bottom (GINPSHL). Initial production was around 3500bfpd with a GLR ~160scf/stb, so the ESP was able to draw down the well, it performed successfully under these conditions, and the unit had a very good run life, it ended up failing after 625 days, when the flowrate declined to ~500bfpd and the GLR had increased to ~1000scf/stb while the pump intake pressure came down from ~2500psi at the initial state to ~550psi, below the bubble point leading to additional free gas going into the pump, causing the unit to start cycling.

For the two upcoming ESP installs on this well, since the reservoir conditions had change and the GLR started to be a problem (~1500scf/stb), gas handling designs were proposed, adding besides the Gas Insurance Pump (GINPSHL) which has the ability to handle increased amount of gas at lower pressure, a Multi Vane Pump, which design allows turbulent mixing to occur which is favorable for flow capacities to carry the gas without becoming stagnant and bigger balancing holes to mitigate the pressure differential, along with a lower flowrate main production pump (FlexER) in order to increase pump efficiency, operating closer to the BEP. Both installations were ineffective, resulting in short runs, one ran for only 26 days and the other one for 195 days, due to having a hard time to keep the well running (see operational trend in Figure 4). Constant shutdowns related to underload and high motor temperature were the main cause of ESP downtime for this well, along with high motor current fluctuation that finally headed to grounded components in both cases. Consequence of this, unstable production rates were experienced during this period (see production chart on the left of Figure 5).

Finally, in January 2020, considering hard well conditions and unsuccessful previous run, in order to recover production losses, customer accepted Multiphase Encapsulated System (Cenesis Phase) proposal. Being able to keep the well running in steady conditions (see comparison of multiphase system operating parameters vs previous run in Figure 6-left). ESP performance improved with a very few shutdowns after new installation, reducing the number of shutdowns by 90% and improving drawdown by 35% after implementing the encapsulated solution, reaching 350psi of pump intake pressure. Unit ran steady for over 200 days, without cycling, with steady production (see chart on the right of Figure 5) and it was proactively pulled for artificial lift method change due to production declination in order to preserve the equipment for another opportunity.

Similar conditions were observed on well #2 from Operator #2. The well initiated production in April 2019 with a flowrate around 2800bfpd, and a GLR of 300scf/stb, but quickly started to decline and by July 2019, flowrate was already ~500bfpd and GLR ~1800scf/stb (see production chart on Figure 7). The first ESP installed was a high-volume pump (P35) with two gas handler pumps at the bottom (GINPSHLs), the unit was able to draw down the well, it performed good as it was expected until the production conditions changed drastically and the pump intake pressure declined to ~650psi from the original 3000psi, dropping below the bubble point what caused instability, starting to have current fluctuation what led to a grounded condition after 120 days.

In August 2019, a gas handling design was proposed, adding besides the two Gas Insurance Pumps (GINPSHL) a Multi Vane gas handling pump (MVPER) and a lower flowrate main production pump (FlexER) with tandem gas separators. This unit was not able to keep the well running on steady conditions, amps fluctuation was around 100amps on the surface, it couldn't draw it down either, keeping PIP around 600psi all the time, with intermittent production due to the constant shutdowns cause by underload and high motor temperature alarms (see operating parameter on Figure 8). Several gas operating modes were tried on the drive as PID and Gas Purge modes without success.

ESP performance was matched with the well conditions using artificial lift simulation software, which indicated a separation efficiency around 75%, reason why free gas going into the system was severely high, GINPSHL (68%), MVPER (67%) and 63% into the FLEXER, which was discharging ~46% (see gas profile in Figure 9). This confirm the gas lock conditions pumps were experiencing, consequence of a high GLR ~2500scf/stb and low flowrates ~400bfpd, since the reservoir was still declining. At this point, a multiphase encapsulated system was proposed to the customer as a solution to this harsh environment, and after ~60 days of run with inconsistent production, Operator #2 decided to pull the unit in order to try the Cenesis Phase System.

The Multiphase Encapsulated System proposed was installed by the end of October 2019 and it was able to draw down the well, pump intake pressure dropped to ~400psi (improving ~34%) and the unit ran in steady conditions, amps fluctuation was considerably reduced and unit was mostly operated at frequency set (operating parameters on Figure 10). ESP performance improved with a very few shutdowns, none of them related to well conditions, these were incoming power events. Number of shutdowns related to underload or high motor temperature was reduced by 92%. Unit ran for over 120 days with steady production, besides GLR spiking over 3500scf/stb (see chart on Figure 7) due to fluid rate declining to ~300bfpd, motor temperature was steady, recirculation system was working properly, without having the unit cycling.

Cenesis Phase System performed successfully, being able to efficiently separate gas (GasSep Eff ~96%), which was not only observed on the smooth operation, but also on the simulation software. Only 36% of free gas was going into the first pump (GI) and by stage number 140 there was 0 GIP on the system (see Figure 11), which means that most of the stages of the main production pumps were not handling any free gas, which increase pump efficiency. This unit as well as the previous one was proactively pulled for artificial lift method change due to production declination in order to preserve the equipment for another opportunity.

CONCLUSIONS

The OPEX for running the Multiphase Encapsulated Production Solution is less than the standard ESP system, which helps justify the investment when running them in gassy well applications. This is supported in the fact that eliminating gas related shutdowns reduces the number of trips that requires troubleshooting the well; it also reduces the amount of time spent by the ESP analyst monitoring the wells. With fewer shutdowns, ESPs last longer, and the resulting improvement in system reliability reduces the number of workover jobs required to repair failed ESP. Uptime has considerably improved, and this decrease in downtime means more consistent oil production and cash flow.

The multiphase encapsulated production solution has proven to be a viable method of improving the operation of ESPs in high GLR environments. Even though the upfront cost is slightly higher than conventional ESP systems, the improvement in uptime and operational efficiencies result in improved economics. Summary results for shutdowns, pump intake pressure and rate improvement can be found in table #1. The estimated separation efficiency (> 90%) of the system positioned the technology as one of the best gas handling options on challenging declined unconventional reservoirs with a wide operating window.

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- Nicholson, B., Tyler, C., Yicon, C. and El Mahbes, R., “Downhole Gas Separation in High-GLR CO2 Application”. 2019.

	Pre-Cenesis Phase			Post-Cenesis Phase		
Well	**UL & MT SD**	**PIP (psi)**	**Total Fluid (BPD)**	**UL & MT SD**	**PIP (psi)**	**Total Fluid (BPD)**
#1	58	540	240	6	350	280
#2	12	610	220	1	400	290

SD % Improvement	PIP % Improvement	Rate % Increase
90	35	14
92	34	24

Table 1 – Summary results for Shutdowns, Pump Intake Pressure and Rate improvement

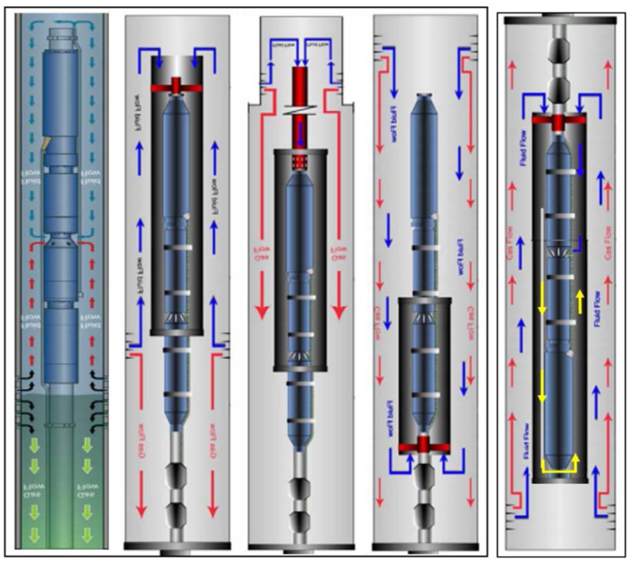

Figure 1 – Left to right: Recirculation System, ESP with Shroud, ESP with Shroud and Dip Tube, ESP with Inverted Shroud, Schematic for Multiphase Encapsulated System

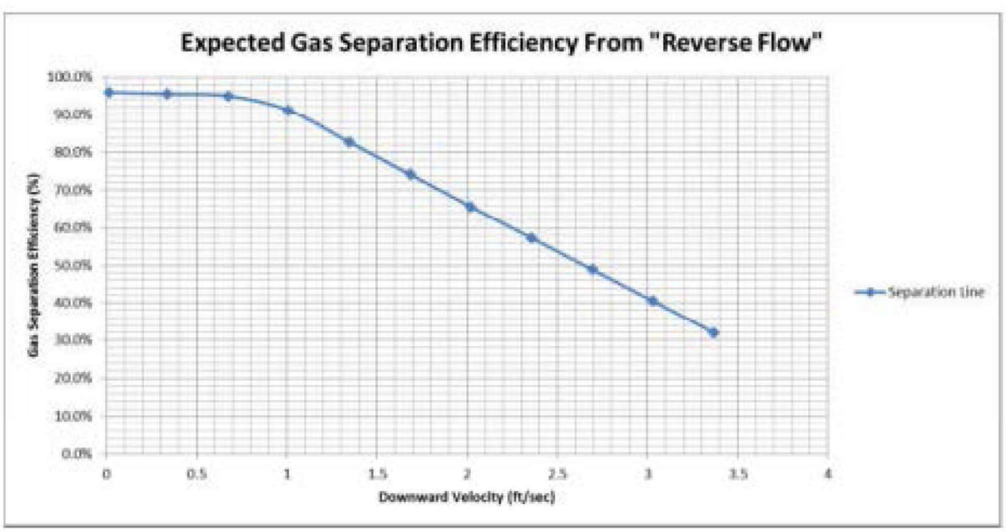

Figure 2 – Gas Separation Efficiency from Reverse Flow

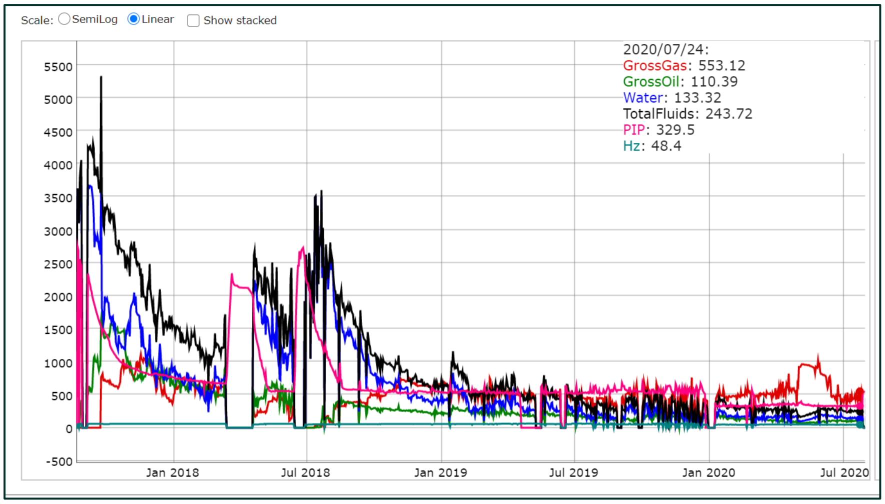

Figure 3 – Historic Production Chart - Well #1

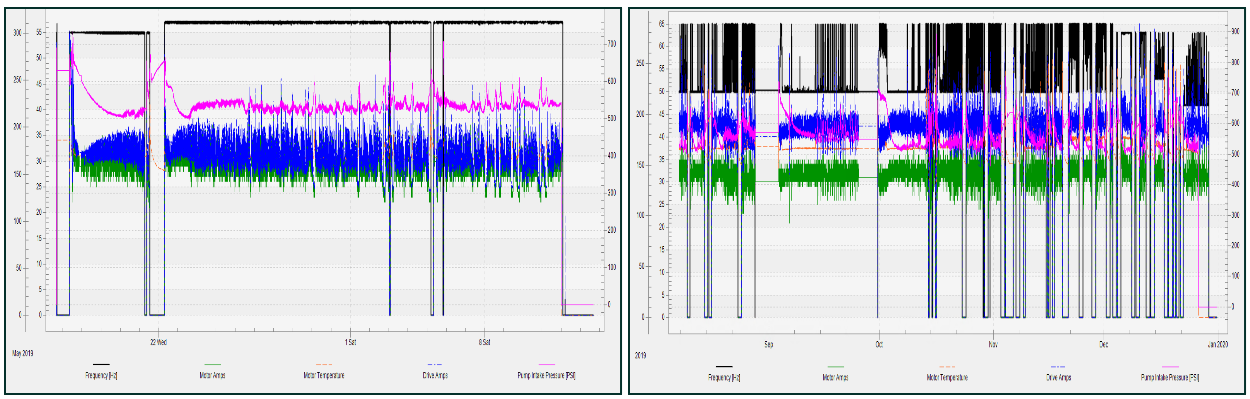

Figure 4 – Operating Parameters Before Cenesis Phase.
Left to right: Second Run (26days), Third Run (195days) – Well #1

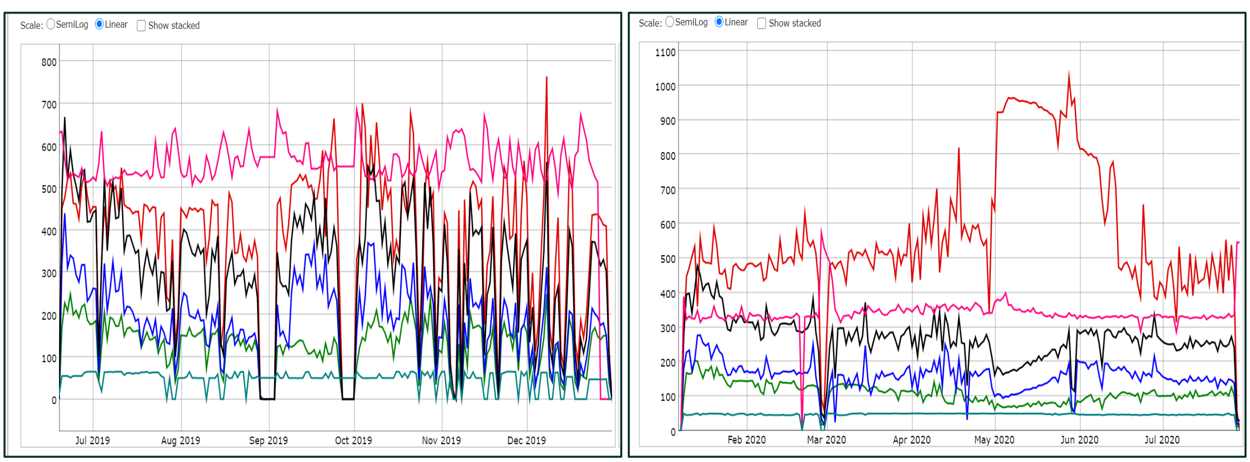

Figure 5 – Production History. Left to right: Second and Third run (Before Cenesis Phase),
Fourth Run (Encapsulated Phase System) – Well #1

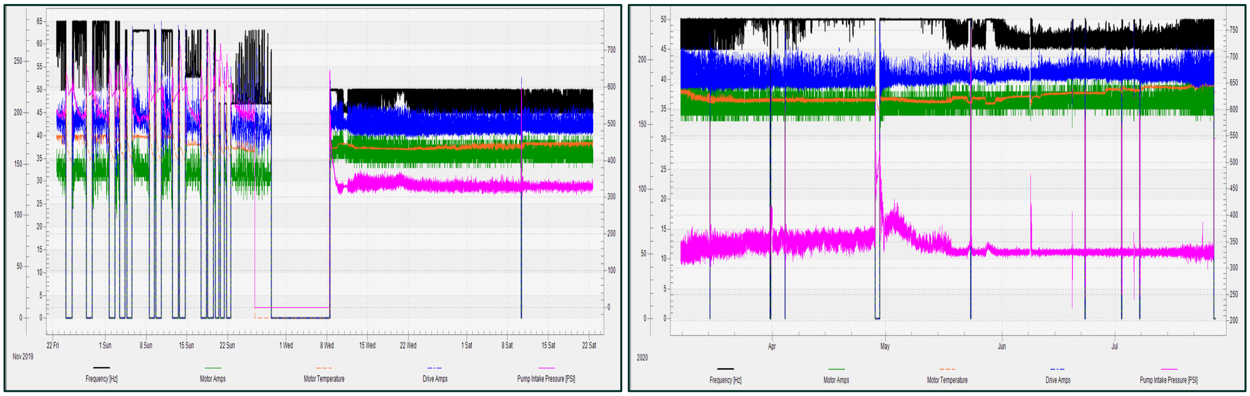

Figure 6 – Operating Parameters. Left to right: Previous run vs Multiphase System Run, Whole Multiphase Run – Well #1

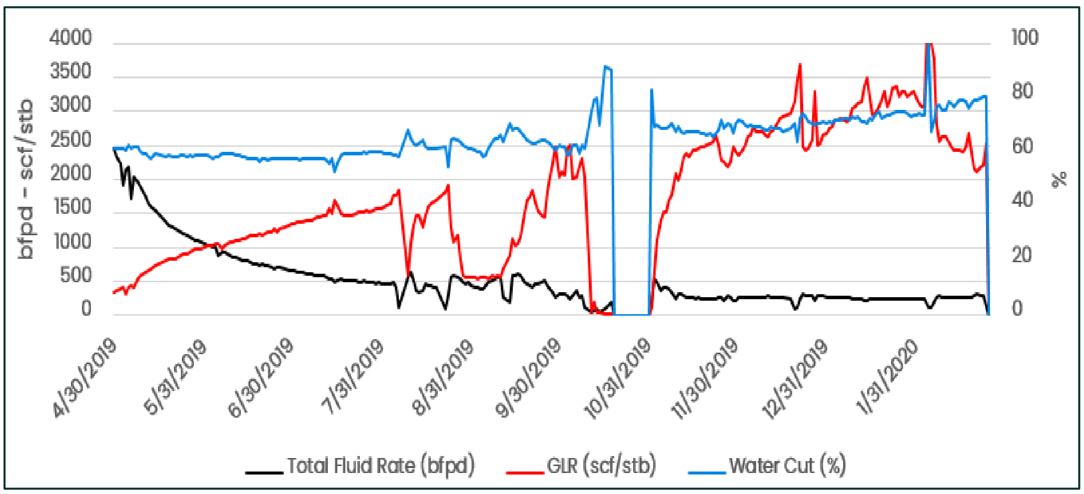

Figure 7 – Historic Production Chart – Well #2

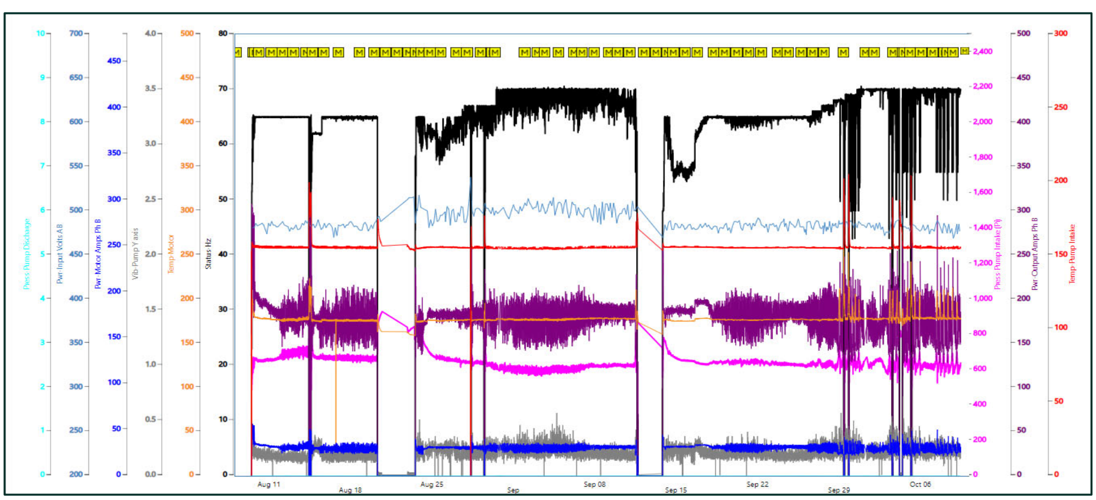

Figure 8 – Operating parameter for Second run (Before Cenesis Phase) – Well #2

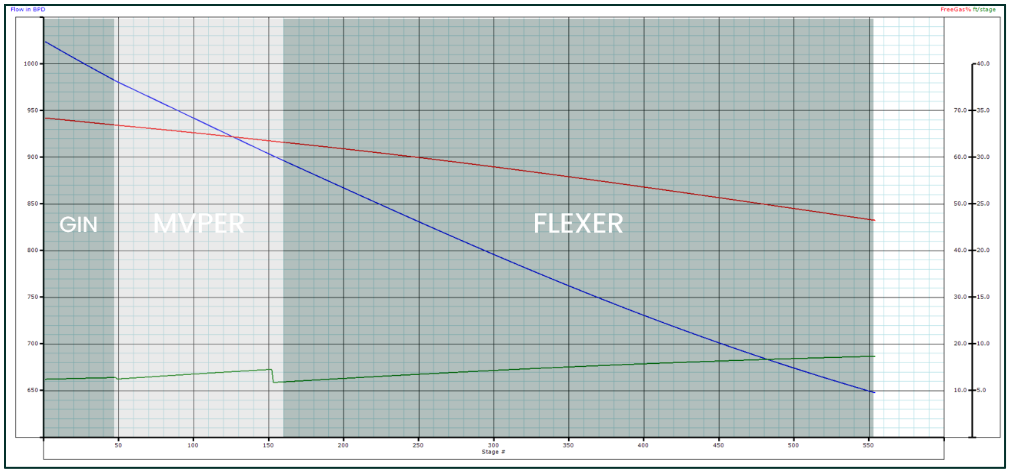

Figure 9 – Free gas into pump per stage profile. ALS simulation software.
Second run (Before Cenesis Phase) – Well #2

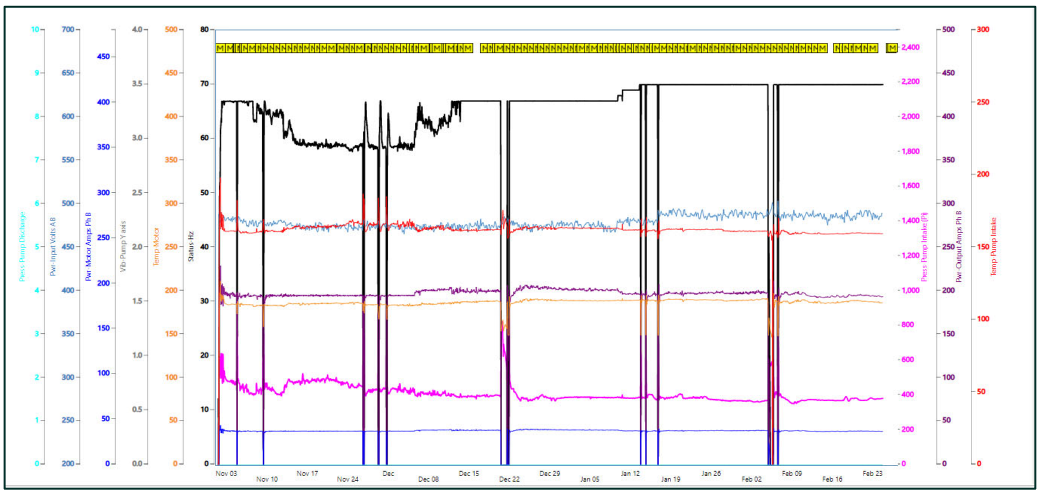

Figure 10 – Operating parameter after Cenesis Phase Install – Well #2

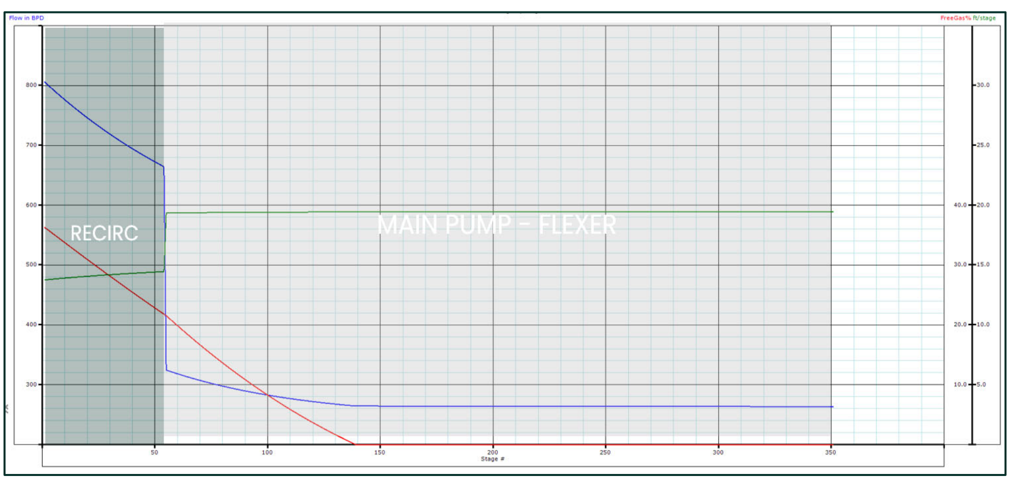

Figure 11 – Free gas into pump per stage profile. ALS simulation software.
Third run (After Cenesis Phase) – Well #2