SUCCESSFUL APPLICATION OF THE CENesis PHASE™ SYSTEM TO IMPROVE ESP RELIABILITY IN GASSY WELLS – LESSONS LEARNED

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ABSTRACT

Electric Submersible Pumps (ESPs) operating in gassy wells often experience unstable performance when free gas enters the pump, leading to gas lock, underload events, elevated motor temperatures, and premature failures. These challenges are exacerbated by gas slugging and high gas-liquid ratios common in unconventional Permian Basin wells. This paper presents field results demonstrating improved ESP reliability and production performance using the CENesis PHASE™ Multiphase Encapsulated System.

The CENesis PHASE™ system fully encapsulates the ESP and stabilizes intake conditions by using density-driven separation of free gas upstream of the pump intake, rather than relying on conventional mechanical vortex gas separators. This approach reduces the volume of free gas entering the ESP and expands the stable operating envelope in gas-dominated flow regimes. Performance of PHASE installations was evaluated through direct before and after comparisons against conventional ESP configurations, with emphasis on shutdown frequency, uptime, intake pressure behavior, and production trends.

Field data from twelve Permian Basin wells converted from conventional ESP systems show consistent reductions in gas-related shutdowns and improved operational stability following PHASE installation. Uptime improvements of 5-15% were observed, along with increased sustained production in wells previously constrained by gas interference. In selected shutdown reduction trials, gas related ESP shutdowns were reduced by up to 94% over equivalent evaluation periods.

INTRODUCTION

Reliable production from gassy wells remains a persistent challenge for ESP applications, as increasing free gas fractions at the pump intake continue to disrupt stable artificial lift performance. In many unconventional and horizontal wells, elevated Gas Liquid Ratio (GLR), transient slugging, and highly variable multiphase flow regimes reduce pump efficiency, promote gas lock conditions, and contribute to premature system failures. These operating instabilities limit achievable drawdown, constrain liquid production, and increase the frequency of well interventions. Despite decades of development, field proven solutions capable of maintaining ESP stability across a broad range of gas dominated operating conditions remain limited.

In high GLR environments, operators have traditionally accepted reduced production targets or implemented supplemental gas management technologies to mitigate the effects of free gas at the ESP intake. Common approaches include advanced gas handling pump stages and vortex type separation devices. While these technologies improve gas handling performance, their effectiveness often degrades as gas rate increases and flowing bottom hole pressure decreases over the life of the well. As wells mature and gas fractions increase, conventional gas separation methodologies frequently reach the limits of their practical effectiveness.

To address these limitations, an alternative gas handling approach was evaluated using the CENesis PHASE™ system, a shrouded and encapsulated ESP configuration designed to stabilize intake conditions rather than rely on conventional gas separation. This paper presents field results from twelve PHASE installations across the Permian Basin. Performance was evaluated and compared directly against prior ESP configurations utilizing conventional gas separator designs. The analysis focuses on quantifying improvements in production stability, system uptime, and operational reliability in wells that previously experienced frequent shutdowns associated with gas lock, underload events, and elevated motor temperatures.

Limitations of Conventional Gas Separators

Conventional downhole gas separators are designed to manage free gas at the ESP intake by separating the liquid and gas phases prior to fluid entry into the pump. While effective within a defined operating range, separator performance is fundamentally constrained by total volumetric flow capacity which is strongly influenced by intake pressure and gas expansion.

As intake pressure declines, free gas expands rapidly, increasing the total volumetric flow rate entering the separator. Although liquid production may remain relatively unchanged, the expanding gas phase can dominate the overall intake volume, exceeding the separator's hydraulic and mechanical separation capacity. Once this volumetric limit is reached, separation efficiency deteriorates and gas is carried into the pump, leading to instability and gas lock conditions.

This dynamic creates a narrowing operating window in gassy wells, particularly under conditions of declining reservoir pressure or rising GLR. Even modest reductions in intake pressure can result in large increases in gas volume, rapidly pushing the separator beyond its effective throughput range. As a result, ESP systems that initially operate within separator design limits often experience deteriorating performance over time, manifested as frequent shutdowns, unstable operating current, underload events, and elevated motor temperatures.

These inherent volumetric limitations underscore a key challenge of conventional gas separation strategies: separator performance is highly sensitive to changing well conditions and does not scale effectively with increasing gas expansion. In wells where free gas fraction continues to rise, alternative intake management approaches are required to sustain reliable ESP operation.

CENesis PHASE System Description

The CENesis PHASE™ system used for this field trial can be seen in Figure 1 – Flow Path through CENesis PHASE. The PHASE system uses standard 4” pumps with a 4.5” motor encapsulated inside of 220’ to 240’ of flush joint, 5.5” 15.5# casing shroud with an OD of 5.5” and ID of 4.95”. The shroud is attached to a joint of 2 3/8” tubing with a specialized shroud hanger above the pump discharge and the ESP hangs inside of the shroud. The motor lead is run through the shroud hanger into the shroud to connect to the motor, and a recirculation tube is run from the top of a recirculation pump down below the motor.

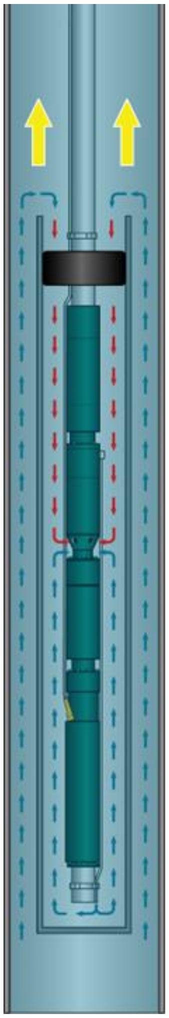

Figure 1 – Flow Path through CENesis PHASE

In the field trial data seen in Tables 2 and 3, Well 9 and Well 10 have specially modified shroud entrances to widen the intake. The intention is to reduce downward velocity of the liquid entering the shroud, seen in Figure 2 - Enlarged Shroud Entrance. This is discussed further in the limitations and results sections.

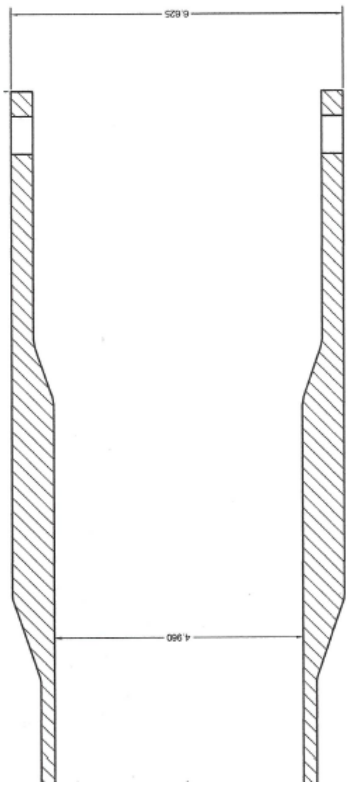

Figure 2 - Enlarged Shroud Entrance

Reverse Flow Intake and Gas Separation Mechanism

In the CENesis PHASE system, produced fluids flow past the ESP and enter the shroud from above the pump, creating a reverse flow path to the intake (Figure 1 – Flow Path through CENesis PHASE). As the multiphase mixture passes above the intake, free gas separates naturally due to buoyancy effects. The lower density gas phase continues to rise within casing annulus, while the denser liquid phase migrates downward toward the pump intake.

By leveraging this density driven separation mechanism, the system reduces the effective free gas volume reaching the intake without imposing the same total volumetric throughput limitations associated with conventional gas separators. Gas is allowed to migrate upward and exit the well, while the liquid rich phase is preferentially delivered to the pump. This approach enables more stable intake conditions across a wider range of gas volume fractions and intake pressures. [4]

Shroud Geometry and Sand Management

To mitigate produced sand accumulation and plugging at the ESP intake, the shroud is extended below the pump intake and motor section before being closed off, rather than terminating at the intake like a typical inverted shroud system. This geometry prevents downward moving solids from settling directly at the intake and promotes continuous fluid movement through the shroud annulus. By positioning the shroud termination below the motor, the design allows for additional space for fall back or produced sand and scale to settle without affecting ESP performance. By terminating the shroud below the ESP and supporting it on the tubing, any weight suspended beneath the shroud is transferred directly to the tubing string rather than through the ESP. This load path isolates the pump, motor, and connection hardware from axial tensile loading, removing the ESP as the limiting factor in suspended weight capacity and allowing for additional tailpipe to be run to capture produced sand.

Motor Cooling and Recirculation System

Because the ESP motor is fully encapsulated within the shroud, natural wellbore flow does not pass over the motor housing. To ensure adequate motor cooling, the PHASE system incorporates a dedicated recirculation pump and recirculation tube that actively circulates produced fluid from the pump intake to below the motor. This forced circulation maintains sufficient fluid velocity past the motor housing, providing consistent heat removal.

Well Selection Criteria

Field evaluation of the CENesis PHASE™ system was conducted using twelve of thirteen active PHASE installations that were converted from conventional ESP configurations at the time of analysis. This approach ensured that the dataset reflected real world deployment decisions rather than selective post performance screening. One currently running installation was excluded from the study because the well was previously produced with a PHASE system and therefore did not allow for direct comparison against prior conventional ESP performance.

Selection of wells for PHASE conversion was driven by documented gas related operational challenges observed during conventional ESP operation. Candidate wells were located in the Delaware Basin with 7 5/8” casing and met one or more of the following criteria:

- Recurring gas related downtime or shutdowns, including wells affected by gas slugging, gas lock events, underload trips, or unstable operating current. In these cases, PHASE deployment was intended to improve uptime and reduce nonproductive operating events. Literature states that the design “eliminates NPT caused by system cycling and gas locking,” directly improving runtime consistency and operational reliability [3].

- Suspected limitations on drawdown and liquid production attributed to free gas interference, where existing ESP systems were unable to maintain stable operation at desired intake pressures. These wells were targeted to evaluate whether stabilizing intake conditions could enable increased production rates.
- General gas interference during ESP operation, including wells operating near or beyond the effective capacity of conventional gas separators, or where separator performance had deteriorated as intake pressure declined and gas volume expanded.

In addition to gas handling considerations, wells were selected with low to moderate sand production rates, defined as under five cups of sand production per day. This criterion was applied to mitigate the risk of solids accumulation and potential plugging within the shroud annulus and intake region during initial field deployment. While the PHASE system incorporates design features intended to minimize sand deposition, wells with severe or uncontrolled solids production were intentionally excluded from this evaluation to limit additional failure mechanisms.

Expected Limitations of the PHASE System

The gas handling effectiveness of the CENesis PHASE™ system is inherently linked to fluid velocity and residence time within the shroud entrance region. Because the system relies on density driven phase separation rather than active mechanical separation, sufficient time and low local velocity are required to allow free gas to separate and migrate upward while the denser liquid phase moves downward toward the pump intake.

As flow rate increases, fluid velocity and turbulence near the shroud entrance also increases. At higher velocities, free gas can become entrained within the downward moving liquid phase, reducing the effectiveness of buoyancy-based separation and increasing the likelihood of gas reaching the pump intake. For this reason, degraded gas separation performance was anticipated at elevated production rates, particularly under conditions of high free gas volume fraction.

Based on hydraulic modeling and design assumptions, the PHASE system was expected to perform optimally when entrance velocities remained below approximately 0.5 ft/s, corresponding to a liquid production range of roughly 800 BPD. Operation beyond this range was expected to reduce gas segregation efficiency and potentially reintroduce gas interference at the ESP intake. Well 2 and Well 3 show indications of this limitation in lack of production increase or loss of production, as well as in fluctuation in amperage while running.

Wells 9 and 10 use specially enlarged shroud entrances, seen in Figure 2 - Enlarged Shroud Entrance, to increase the area of the shroud entrance by nearly 50% (Table 1 - Shroud Entrance Comparison). Computational modeling of this shroud entrance showed increased separation capability compared to the standard 5.5” casing shroud entrance, initial example results shown in Figure 3 - Computational Fluid Dynamics Model of Shroud Entrance.

This trial is ongoing, and more data points are needed to fully evaluate the change in production with this shroud entrance.

Casing / Entrance ID	Tubing OD	Annular Area (ft²)	Velocity Limit (ft/s)	Liquid Rate (BPD)
Enlarged Entrance - 5.75” ID	2⅜ in	0.150	0.5	~1,150
5.5” Casing - 4.95” ID	2⅜ in	0.103	0.5	~790

Table 1 - Shroud Entrance Comparison

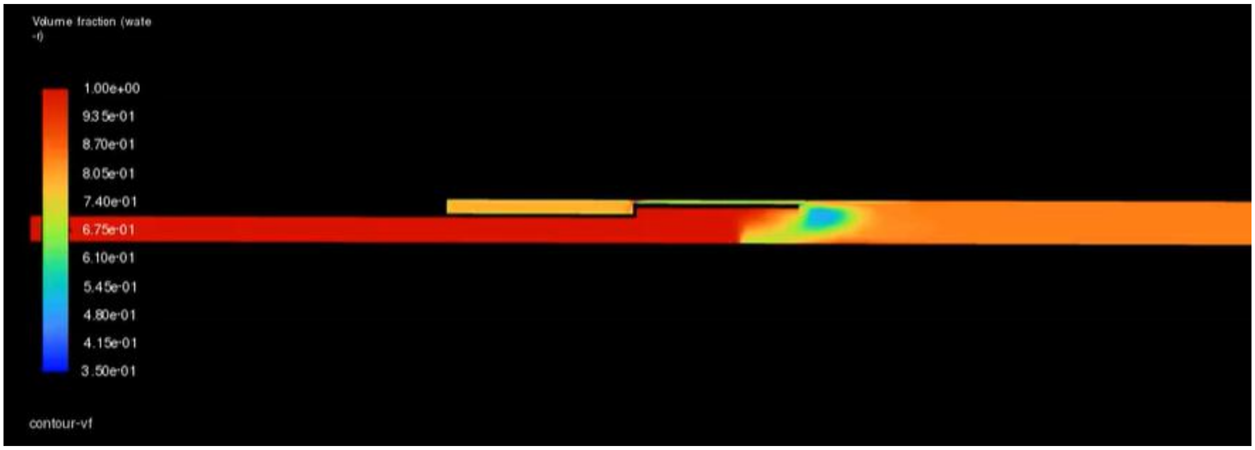

Figure 3 - Computational Fluid Dynamics Model of Shroud Entrance

Trial Evaluation Methodology

The primary objectives of the CENesis PHASE™ field trial were to:

- Reduce gas related ESP shutdown events
- Improve or recover constrained production
- Extend effective ESP run life through improved operational stability

To evaluate performance relative to prior conventional ESP configurations, a consistent comparison framework was applied across all wells.

Shutdown Analysis

Gas related shutdown performance was evaluated by comparing shutdown frequency before and after PHASE installation using defined time windows. Facility related and power rated shutdowns are excluded from the data. For conventional ESPs, shutdown events were reviewed over the four months leading up to ESP replacement, with a deliberate exclusion of the final month immediately preceding failure.

Although shutdown data was available for this final month, field experience indicates that ESPs approaching mechanical or electrical failure often exhibit an elevated frequency of shutdowns unrelated to gas handling alone. Including this period would therefore bias results toward end-of-life behavior rather than representative gas handling performance. As a result, only the three-month period from four months to one month prior to failure was used to characterize baseline shutdown performance for conventional systems.

For PHASE installations, shutdown frequency was evaluated over the three-month period immediately following startup, allowing for direct comparison using equivalent time durations. This approach provided a consistent basis for assessing changes in gas related downtime while minimizing the influence of late life degradation in the conventional ESP population.

Production Performance Evaluation

Production performance was assessed by comparing maximum sustained, stable operating conditions observed before and after PHASE installation. For each well:

- Conventional ESP performance was evaluated using the highest stable production rate achieved during the three months prior to failure, excluding short duration peaks or transient operating periods.
- PHASE system performance was evaluated using the highest stable production rate achieved following installation, once operating conditions had stabilized.

Production metrics included:

- Oil production rate
- Gas production rate
- ESP intake pressure

Gas production was considered the most reliable proxy for total produced volume. Changes in gas production, when evaluated alongside intake pressure behavior, provided a robust indicator of drawdown capability and overall system performance under gas interference conditions.

Results

Field performance of the CENesis PHASE™ system was evaluated across twelve wells converted from conventional ESP configurations. The dataset represents a cross-section of installations selected primarily for gas-related performance limitations under conventional ESP operation, including frequent shutdowns, gas lock events, drawdown constraints, or general instability attributed to high free gas fractions at the pump intake.

Across the evaluated population, PHASE installations demonstrated improved operational stability, reduced gas-related shutdown frequency, and sustained production at comparable or increased drawdown conditions relative to prior conventional ESP systems. Performance improvements were observed across multiple selection categories, including wells installed specifically to reduce shutdowns as well as wells targeted for increased drawdown and production recovery.

The results will be broken into three groupings based on selection criteria: reduction in shutdown frequency, production and drawdown performance, and general gas interference.

Shutdown Reduction Selected Wells

A primary objective of the PHASE deployment was to reduce gas-related ESP shutdown events. Shutdown performance was evaluated using equivalent three-month windows before and after installation, as defined in the methodology section. Wells selected for shutdown reduction showed a consistent decrease in gas-related shutdown events following PHASE installation. Table 2 presents the change in shutdown behavior before and after PHASE installation.

The results of the five wells selected with the goal of reducing the number of gas-related shutdowns were successful in all five trials, with a 94% reduction in the number of shutdowns over a three-month period. Stable oil and gas production also increased in four of the five cases, even excluding downtime associated with higher shutdown frequency with conventional ESP systems. Well #2 showed a large loss of production assumed to be associated with the high gas and liquid combined rates reducing efficiency of gravity driven separation.

	Shutdowns			Conventional Production Data						Phase Production Data					
Well	Three Month Conventional ESP Shutdowns	Three Month Phase Shutdowns	Change in Shutdowns Per Month	Gas Rate (MCFD)	Oil Rate (BPD)	Water Rate (BPD)	Total Liquid (BPD)	GLR	PIP (psi)	Gas Rate (MCFD)	Oil Rate (BPD)	Water Rate (BPD)	Total Liquid (BPD)	GLR	PIP (psi)
Well 1	11	4	**-2.33**	1150	165	920	1085	1060	420	1450	210	975	1185	1224	381*
Well 2	24	0	**-8**	1480	110	850	960	1542	515	895	78	630	708	1264	606
Well 6	13	0	**-4.33**	1080	105	640	745	1450	335	1100	120	590	710	1549	270
Well 9	36	0	**-12**	1395	185	940	1125	1240	970	1770	190	600	790	2241	611
Well 12	28	3	**-8.44**	750	90	510	600	1250	850	930	115	770	885	1051	365

Table 2 - Shutdown Reduction Trial Wells

*Well 1 set depth was increased by 950 feet.

Production and Drawdown Performance Wells

Production performance was evaluated using maximum sustained, stable operating rates before and after PHASE installation. Across the wells selected for drawdown improvement, PHASE installations enabled sustained or increased gas and liquid production while maintaining stable intake pressures. In these wells, conventional ESP systems had previously exhibited instability or were unable to operate at desired drawdown conditions without shutdowns. The observed production behavior suggests that stabilizing intake conditions expanded the practical operating envelope of the ESP systems under multiphase flow.

Table 3 presents changes in production after installation of the PHASE system. In Wells 4, 5, 8, and 10 an additional average of 240 MCF of gas was produced, an increase of 24%. In Well 3 production remained stable. The lack of production increase using the PHASE ESP system is attributed to the high flow rate compared to the expected effective velocity required for the buoyancy to drive gas separation.

	Shutdowns		Conventional Production Data						Phase Production Data						Change In Max Production		
Well Name	Three Month Conventional ESP Shutdowns	Three Month Phase Shutdowns	Gas Rate (MCFD)	Oil Rate (BPD)	Water Rate (BPD)	Total Liquid (BPD)	GLR	PIP (psi)	Gas Rate (MCFD)	Oil Rate (BPD)	Water Rate (BPD)	Total Liquid (BPD)	GLR	PIP (psi)	Change in Gas (MCFD)	Change in PIP (psi)	Change in Oil (BPD)
Well 3	0	4	930	62	1070	1132	822	600	950	70	970	1040	913	600	+20	0	8 BPD
Well 4	0	0	940	87	460	547	1718	555	1065	90	390	480	2219	455	+125	-100	3 BPD
Well 5	0	0	830	80	550	630	1317	670	1220	95	550	645	1891	470	+390	-200	15 BPD
Well 8	1	0	1110	97	657	754	1469	565	1200	105	711	816	1471	500	+90	-65	8 BPD
Well 10	5	0	1130	155	660	815	1387	640	1490	190	690	880	1693	300	+360	-340	35 BPD

Table 3 - Production and Drawdown Trial Wells

General Gas Interference

The remaining wells were classified under general gas interference, where conventional ESP operation was characterized by unstable performance due to high GLR, variable flow regimes, or operation near the upper capacity of conventional gas separators. These wells did not always exhibit frequent shutdowns but commonly operated with large amp and production swings. Table 4 presents before and after performance.

In Well 7, a small increase in drawdown and production gain was achieved using the PHASE system, although the unit was near pump off conditions both with the original conventional ESP system and the PHASE system.

In Well 11 the unit was set deeper in the well, causing intake pressure to rise, but a small loss in production was observed. Well 11 was unique in the field trial as the GLR was over 3000 MCF/BPD, which may have contributed to annular liquid flow under both conventional and PHASE configurations.

	Shutdowns		Conventional Production Data						Phase Production Data						Change In Max Production		
Well Name	**Three Month Conventional ESP Shutdowns**	**Three Month Phase Shutdowns**	**Gas Rate (MCFD)**	**Oil Rate (BPD)**	**Water Rate (BPD)**	**Total Liquid (BPD)**	**GLR**	**PIP (psi)**	**Gas Rate (MCFD)**	**Oil Rate (BPD)**	**Water Rate (BPD)**	**Total Liquid (BPD)**	**GLR**	**PIP (psi)**	**Change in Gas (MCFD)**	**Change in PIP (psi)**	**Change in Oil (BPD)**
Well 7	3	2	520	30	300	330	1576	270	550	35	355	390	1410	245	30	-25	5
Well 11	0	0	1030	60	240	300	3433	480	1020	50	250	300	3400	681	-10	201*	-10

Table 4 - Gas Interference Trial Wells

*Well 11 set depth was increased by 750 feet.

Case Studies

While aggregated results demonstrate consistent improvements in ESP stability and performance across the evaluated well population, average trends can mask well-specific operating dynamics and installation-level behavior. To further illustrate how the CENesis PHASE™ system performs under varying gas interference mechanisms, two representative case studies are presented in the following section.

These case studies were selected to highlight distinct application drivers and operating conditions observed during the field trial, including shutdown mitigation and drawdown limitation under elevated gas volume. Detailed production trends, intake pressure behavior, operational history, and downhole configuration information are used to provide greater insight into the mechanisms contributing to improved performance.

1st Case Study – Well 9

The first case study focuses on a well that struggles with severe gas interference. As shown in Table 5, the initial ESP relied on a conventional gas handling approach. After transitioning to a CENesis PHASE™ configuration, the system no longer required dedicated gas handling and oversized pumps.

Equipment	**Install**	**Install**
Pump	288 Stages – E3000	536 Stages – Flex17-5
Gas Handler / Recirc Pump	78 Stages – G42 Gas Handler	26 Stages – Flex17-5 Recirc
Motor	5.62” IM – 350HP	4.5” IM – 220HP
Methodology	Conventional	CENesis PHASE™

Table 5 - Case Study 1 Conventional vs CENesis PHASE™ ESP String Comparison.

The first well exhibited severe gas interference behavior as production declined. The operating trends of the conventional ESP, shown in Figure 4, indicate that the system was functioning under PID control. Despite continuous corrective adjustments, the pump frequency oscillated between 52 and 65 Hz and was unable to prevent repeated shutdowns caused by underload conditions and elevated motor temperatures associated with the high gas–liquid ratio. These severe fluctuations were predominantly driven by gas interference, which led to persistent high-temperature trips throughout the run. The cumulative impact of these events resulted in a total downtime of 18%, significantly reducing operational efficiency and limiting the well’s ability to sustain the targeted liquid production rate.

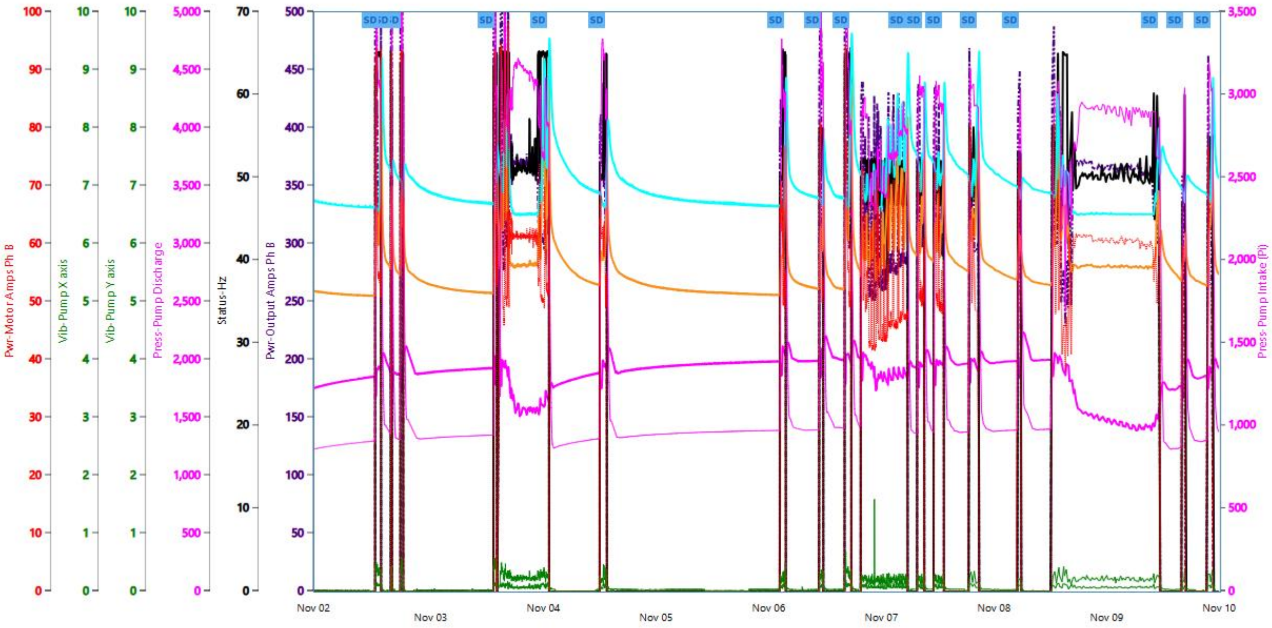

Figure 4 - Case Study 1's Operating Parameters with Conventional ESP.

The recurring shutdowns and restricted drawdown ultimately necessitated retrieval of the conventional ESP and deployment of the CENesis PHASE™ system, which is engineered to maintain stable operation under elevated gas-liquid ratios. Figure 1 presents the installed ESP configuration incorporating the CENesis PHASE™ system. Despite operating at lower intake pressures and under severe gas interference, the system delivered markedly improved stability, eliminating the frequent cycling previously observed.

This operational stability directly translated into a significant increase in system uptime, from 82% to 97% as illustrated in Figure 5.

Figure 5 - Case Study 1 Uptime Comparison

The improved uptime is clearly correlated with the enhanced ESP performance. Demonstrated in Figure 6, the increased reliability of the ESP prevented repeated trips and sustained continuous production. The reduction in downtime by 15% contributed to measurable production gains across the evaluated period.

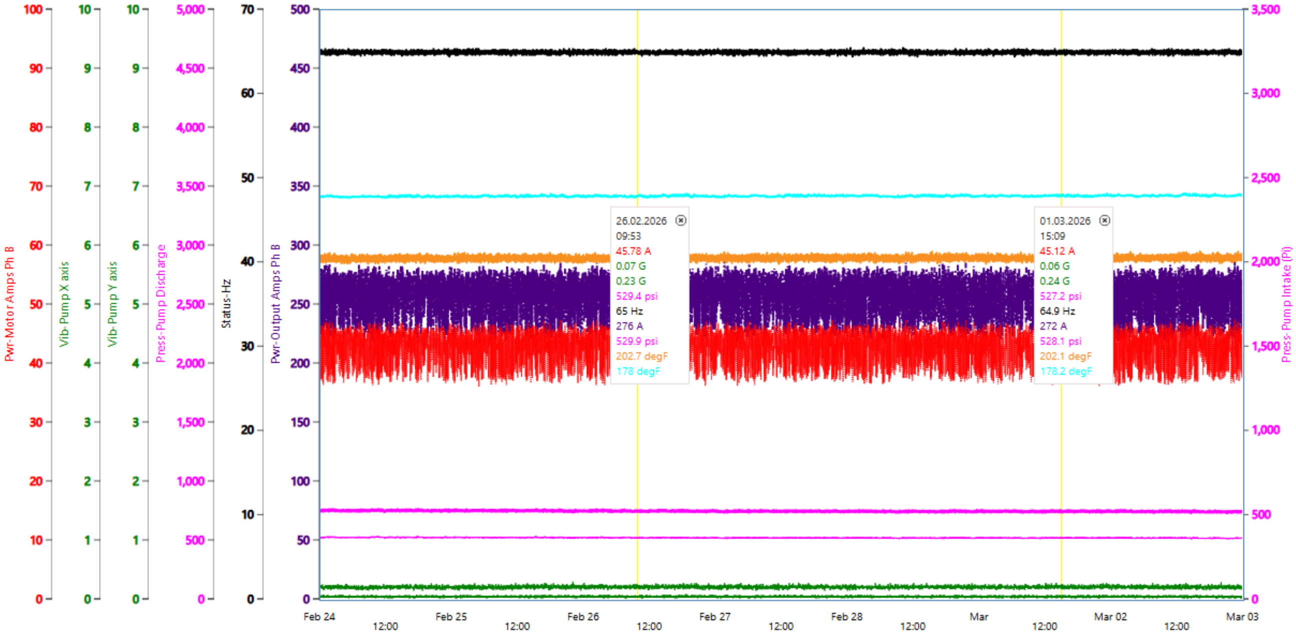

Figure 6 - Case Study 1's Operating Parameters with CENesis PHASE™

2nd Case Study – Well 12

The second case study examines a well that similarly faced escalating gas interference. As summarized in Table 6, the conventional ESP instillation utilized oversized pumps and gas handling to manage the presence of gas. The following installation removed the need for these gas management systems and allowed the well to operate with more efficient pumps.

Equipment	**Install**	**Install**
Pump	268 Stages – E2000 96 Stages – E3000	366 Stages – E1000 134 Stages – Flex 17-5
Gas Handler / Recirc Pump	16 Stages – GH 2500 Gas Handler	69 Stages – MVPER Recirc
Motor	5.62” IM – 225HP	4.5” IM – 187HP
Methodology	Conventional	CENesis PHASE™

Table 6 - Case Study 2 Conventional vs CENesis PHASE™ ESP String Comparison.

The second well also suffered from severe gas interference. As illustrated in Figure 7, the presence of gas caused mass fluctuations within the operating trends. Persistent gas prevented the system from running at a sustained target frequency of 58 Hz. Conventional gas handling was initially effective, but as the pressure was drawn down and volume of gas increased, the standard gas handling methods became insufficient and lead to shutdowns. The cumulative impact of these shutdowns resulted in a total downtime of 14%, significantly reducing the operational efficiency and preventing the ESP from sustaining a constant production rate.

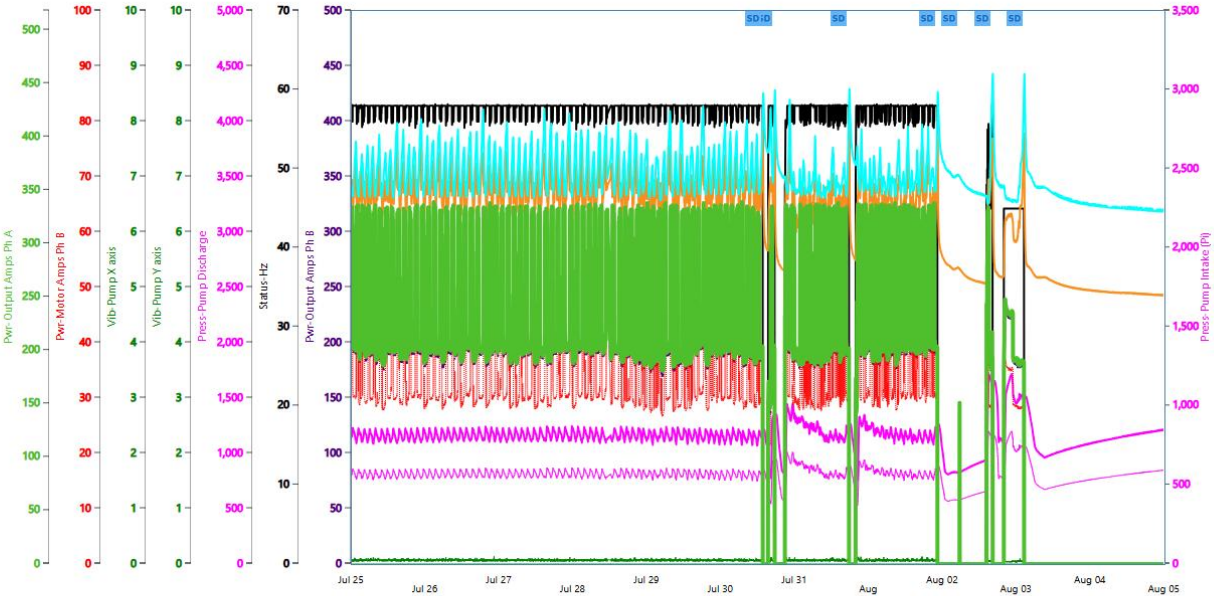

Figure 7 - Case Study 2’s Operating Parameters with Conventional ESP.

The reoccurring shutdowns and instability resulted in pulling the current ESP with a CENesis PHASE™ system. Figure 8 shows the difference in uptime percentage between the two systems. The operational stability improves drastically as the uptime jumps from 86% to 96%.

Figure 8 - Case Study 2 Uptime Comparison

The increase in stability is also reflected in the operational trends. As seen in Figure 9, the fluctuations in the trends have subsided. The prevention of free gas entering the system results in a significant decrease in shutdowns. The additional uptime of the ESP for this well resulted in an increase of 27% more oil production.

Figure 9 - Case Study 2's Operating Parameters with CENesis PHASE™

Case Study Observations

Across both case studies, improved ESP performance was primarily attributed to stabilization of intake flow conditions under elevated gas volume rather than changes in reservoir deliverability or surface operating strategy. In both wells, PHASE installations demonstrated increased tolerance to transient gas slugs and higher GLR without reintroducing shutdowns or erratic operating behavior.

While the drivers for PHASE deployment differed between the two wells - shutdown mitigation in one case and drawdown limitation in the other, the underlying mechanism of intake stabilization produced consistent performance improvements. These observations are consistent with the aggregated field trial results presented earlier and support the broader applicability of the PHASE system in gas-dominated horizontal wells.

Key Learnings

Field deployment of the CENesis PHASE™ system across a range of gassy ESP applications yielded several important technical and operational learnings that may guide future artificial lift design and well selection strategies.

First, reduction in gas-related shutdowns was the most consistent and impactful benefit observed. Wells selected specifically to address frequent underload, gas locking, and motor temperature shutdowns experienced shutdown reductions of up to 94% within the first three months of PHASE operation. This improvement translated directly into higher system uptime and reduced operational intervention.

Second, typically wells with 800 BPD or less liquid rates saw the largest production gains from the PHASE systems. Wells producing higher liquid rates (Well 2, Well 3) saw minimal changes in production or a loss of production when installing the PHASE system. This is expected to be a limitation in flow rate based on fluid velocities.

Third, due to the nature of the encapsulated system sand and scale can cause plugging issues inside the shroud. Often during the pull of a failed PHASE system, the desander tailpipe and the bottom of the shroud would be full of sand. The use of additional tailpipe to capture sand and delay the passage of sand to the ESP intake can improve run life and reliability. Because the desander and tailpipe weight is transferred through the shroud directly to the tubing, more tailpipe can be run on a PHASE system than a conventional ESP, which would be limited by weight hanging off the motor.

Fourth, although reliability was not the main criteria for determining success or failure of the PHASE system trials, there were some key learnings. Across the 30+ installations of

PHASE systems from which this field trial subset was used, there was only a single pull of a PHASE system in under six months, and it was a proactive non-ESP failure. That is in comparison to the larger group of ESP workover installs with as many as 20% failures by the six-month mark. Beyond six months the failure rate of PHASE systems approaches a similar survival curve seen in conventional ESPs, seen in Figure 10. The reduction in less than six-month ESP failures may be attributed to a reduction of shutdowns, gas interference, and increased protection of the motor lead and motor inside of the shroud both physically and with continuous recirculation of fluid for cooling via the recirculation pump. Further improvements in run time may be attainable through the use of longer desander tailpipe and improved chemical treatments.

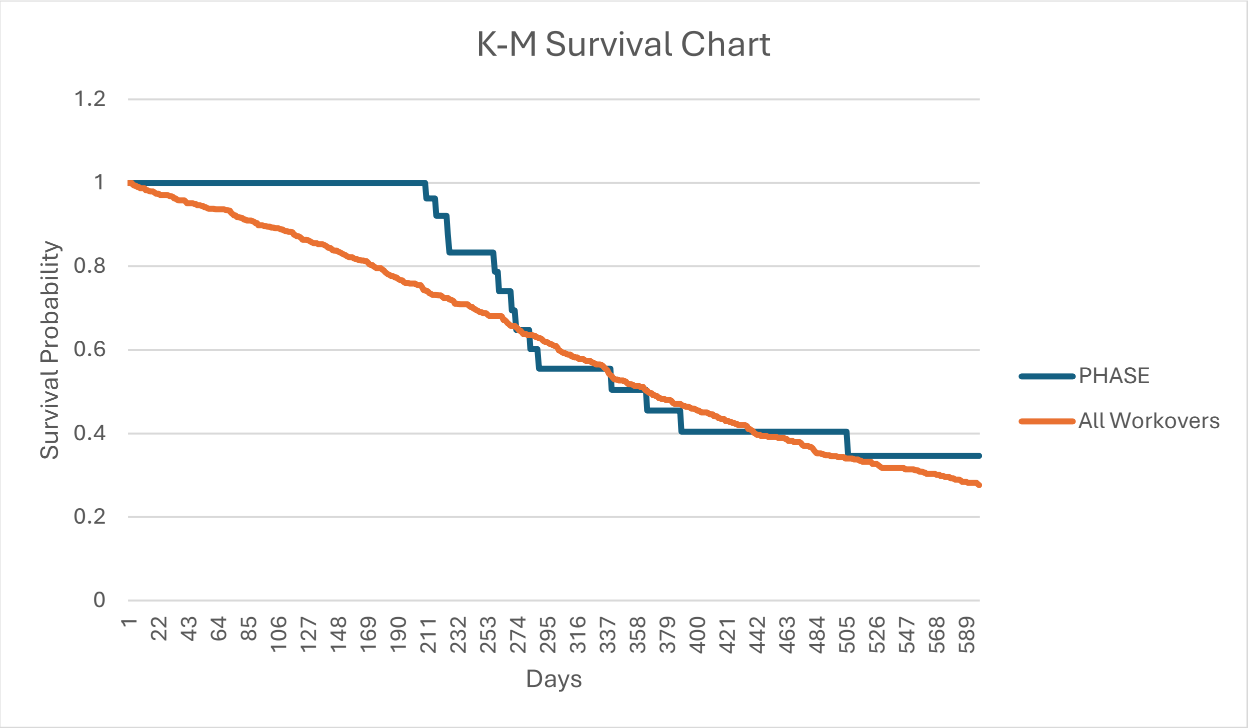

Figure 1 - Survival Curve

Fifth, additional research is needed on options and opportunities to reduce liquid velocities at the intake of the shroud. Initial testing of the larger shroud opening showed promising but not yet definitive results. Well 9 and Well 10 with the larger shroud opening have the highest gas production of any of the systems, conventional or PHASE, and saw the largest gain in gas production and decrease in intake pressure. Expanding production range of the PHASE unit to 1000+ BPD would result in additional opportunities for ESP performance benefits.

Conclusion

Electric Submersible Pump performance in gassy wells is fundamentally constrained by the ability to manage expanding free gas at low intake pressures. Field results presented in this study confirm that conventional gas separation approaches are limited by volumetric throughput and become increasingly ineffective as gas-liquid ratios rise and reservoir pressure declines. These limitations often manifest as unstable operation, frequent shutdowns, restricted drawdown, and reduced ESP run life.

Field deployment of the CENesis PHASE™ Multiphase Encapsulated System demonstrated that stabilizing intake flow conditions upstream of the pump provides a robust and field-proven alternative to conventional mechanical gas separation. By leveraging encapsulation and density-driven phase separation, the PHASE system consistently reduced the volume of free gas entering the ESP, enabling stable operation across a broader range of gas-dominated flow regimes.

Across twelve Permian Basin wells converted from conventional ESP configurations, PHASE installations achieved measurable improvements in operational reliability and production performance. Gas-related shutdowns were significantly reduced by as much as 94% in shutdown-reduction trials, resulting in overall uptime improvements of 5-15%. In wells previously constrained by gas interference, stabilized intake conditions enabled sustained operation at equal or greater drawdown, translating into recovered gas and liquid production without reintroducing operational instability.

Case study results further demonstrated that PHASE installations allowed simplified ESP string designs, reduced reliance on oversized pumps and extensive gas-handling stages, and lower overall system horsepower while maintaining or improving well performance. These outcomes highlight that improved ESP reliability was driven primarily by intake stabilization rather than changes in reservoir deliverability or surface operating strategy.

The results of this study confirm that managing multiphase intake behavior rather than incrementally increasing mechanical gas handling capacity can materially improve ESP run life, uptime, and production in gassy unconventional wells. The CENesis PHASE™ system provides an effective and scalable solution for operators seeking to overcome gas-related ESP limitations and sustain artificial lift performance as wells mature and gas volumes increase.

ACKNOWLEDGMENT

The authors would like to thank BPX and Baker Hughes for their support and permission to publish the paper.

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