GAS FLOW MANAGEMENT TECHNOLOGY DESIGNED TO DECREASE DOWNTIME AND IMPROVE ESP EFFICIENCY – (MIDLAND BASIN)

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ABSTRACT

This paper explains the configuration, design, and mechanisms of an advanced gas regulator system installed underneath the ESP sensor to decrease downtime and stabilize the operational parameters of the pump. The gas regulation principle is based on the changes in the flow regimes found in unconventional wells where typically, gas slugging and high GLR frequently cause shutdowns and motor overheating.

The case study presented in this abstract refers to a well-localized in Midland Basin that had a history of multiple shutdowns, erratic current behavior, unstable PIP, and high motor temperature peaks, all caused by a combination of high GLR and low fluid rates (for ESPs). The well produced a GOR of 5,959.6 SCF/STB and a GLR of 1,609 SCF/STB with a liquid rate of 330 BPD. The main objective of the installation of the Gas Flow management technology was to allow the ESP to run longer and deplete the PIP without cycling (less downtime) and maintaining a constant motor load. After the installation, the ESP has not had any shutdowns due to gas in 3 months, operation frequency started at 50 Hz and then increased to 55 Hz which allowed it to deplete the PIP from 720 psi down to 465 psi.

INTRODUCTION

The Lower Sprayberry formation is a prolific hydrocarbon reservoir located in the Midland Basin of West Texas (Figure 1). This reservoir is being developed through the drilling of unconventional wells that are characterized by a rapid decline of the harmonic type, going from productions of 3,000 -5,000 BFPD down to 500 BFPD in the first ESP run. No many issues are found during the first run of the ESPs but in later installations the drop in the pressure brings challenges to maintain a stable pump operation. The production of gas in this area has led to several challenges related to the use of electrical submersible pumps (ESPs). These pumps are commonly used to increase the flow of oil from wells, but they can become damaged or fail prematurely due to the presence of gas. This has led to a number of operational and financial difficulties for operators in this area, as they try to balance production goals with the need to maintain reliable equipment. In addition to the challenges caused by gas production, the use of other types of artificial lift systems in this part of the Midland Basin can also be limited by factors such as location, logistics, and infrastructure. For example, some areas of the formation may be to close to the Midland city boundaries which limit the installation of certain types of equipment. One potential solution to the ESP problems caused by gas production in this area is to convert wells prematurely from ESP to rod pump systems. Rod pumps are less sensitive to gas interference and can provide more reliable and cost-effective lift in some cases. However, this approach also has its limitations and can result in significant losses in oil production. When wells are converted prematurely, operators may lose access to the full production potential of the well, which can lead to a decrease in oil production by 50 barrels or more. This loss in production can be particularly significant in high-performing wells, which may have been optimized for ESP production and may not be as well-suited for rod pump systems.

These logistical and infrastructure challenges can create additional barriers to efficient and profitable production in this field of Conoco Phillips, further emphasizing the importance of developing effective solutions to address ESP problems and optimize the use of available equipment. In this context, it is important to understand the challenges posed by ESP problems caused by gas, and to explore potential solutions that can help to overcome these obstacles and improve the efficiency and profitability of operations in this region.

Figure 1 Area of study in the Midland Basin – Source: U.S. EIA; BUREAU OF ECONOMIC GEOLOGY; U.S. GEOLOGICAL SURVEY

FIELD BACKGROUND AND CHALLENGES

This oil field is located in the Midland Basin and has been operated by Conoco Phillips since last decade. The field comprises a number of wells that have been developed using electrical submersible pumps (ESPs), Gas Lift and rod pump to increase oil production rates. However, in recent years, the field has experienced several challenges related to gas production and the use of ESPs. Many of the wells have depleted over time, with production rates falling below 500 barrels of fluid per day. This has been compounded by gas-liquid ratios (GLRs) up to 3000 SCF/STB, which have led to a range of issues with ESPs. Through the experience, it has been found that ESPs start to have problems when GLRs reach between 500 and 1000 SCF/STB which has severely limited the effectiveness of this lift system in the field. Although the field does not have significant sand issues, some wells have experienced corrosion and scale-related problems, including holes in the tubing. These issues have further complicated production operations and add to the costs associated with maintaining and repairing equipment.

To overcome the gas-related problems with ESPs, different technologies and approaches have been explored. These have included conventional ESPs with gas handlers and tapered designs, as well as permanent magnet motor (PMM) technologies that can offer improved performance in high gas environments. Additionally, the operator has experimented with smaller motor outer diameters (ODs) to facilitate better natural gas separation and reduce the impact of gas interference on equipment. Despite these efforts, high motor temperatures have continued to be a significant issue, leading to frequent shutdowns and the need for costly repairs and replacements (Figure 2). Because of this, the operator has begun to convert wells from ESP to rod pump when the well reaches a production rate of around 250 barrels per day, which is considered the threshold for the severity of gas-related issues with ESPs. While this approach can help to maintain production rates, it also has the potential to result in significant losses of oil and gas output, further highlighting the challenges of operating in this environment.

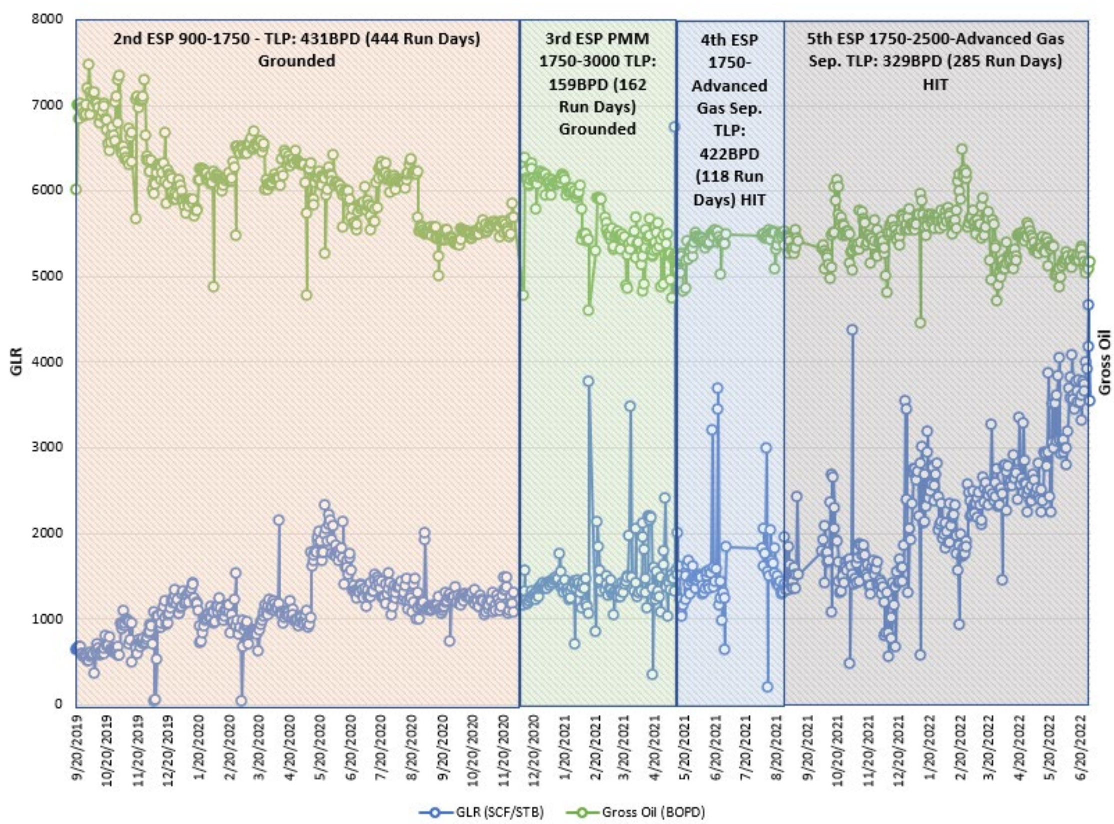

Figure 2 Historical behavior from a well and technologies used.

The production team was forced to find new solutions that can help to manage gas interference and reduce the impact of high temperatures on ESP equipment. These include the use of emerging ESP gas handler technologies that can more effectively manage the gas and liquid phases, as well as innovations in cooling mechanisms that can improve performance in gassy wells.

NEW GAS FLOW MANAGEMENT SYSTEM FOR ESPs

In a slug flow regime, large bubbles of gas and oil travel to the ESP, causing pressure fluctuations that can lead to motor overheating and damage. In contrast, a dispersed bubble flow regime involves smaller bubbles of gas in the liquid phase the move directly to the pump, reducing the pressure fluctuations and the associated overheating caused by the free gas flowing around the motor (Figure 3). The new technology uses a specially designed downhole flow control device to create a dispersed bubble flow regime in the ESP. This device is installed in the wellbore below the pump and contains a series of components that create the desired flow pattern. By reducing the size of the bubbles and increasing their dispersion, the device improves the pump's performance and reduces motor overheating.

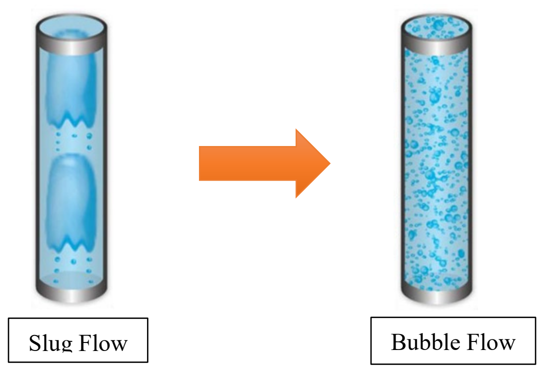

Figure 3 Flow regime changes caused by the new technology.

The system works changing the gas liquid ratio before the gas slug reaches the pump. Four fundamental components contribute to changing the flow regime from slugging to dispersed bubbles: 1. The cup type packer installed just below the sensor, isolating the intake from the pump and preventing free gas slug from flowing into the pump. 2. The slotted body installed below the packer with an internal pipe, which stores the production liquid where the free gas will enter to be dispersed into the liquid phase. 3. The vortex regulator located at the end of the internal pipe, which is responsible for centrifuging the liquid and gas phases, creating a more homogeneous multiphase system, eliminating the continuous gas phase. 4. Finally, the Surge Valve installed in the head of the internal pipe and right below the packer and is responsible for dosing the amount of fluid flowing from the vortex regulator to the pump. This last component works with the balance of the pressure of the perforations and the hydrostatic pressure of the fluid above the packer (Figure 4).

An additional function of the new ESP vortex regulator is to allow the injection of fluids through the surge valve, allowing communication between the upper and lower section of the packer.

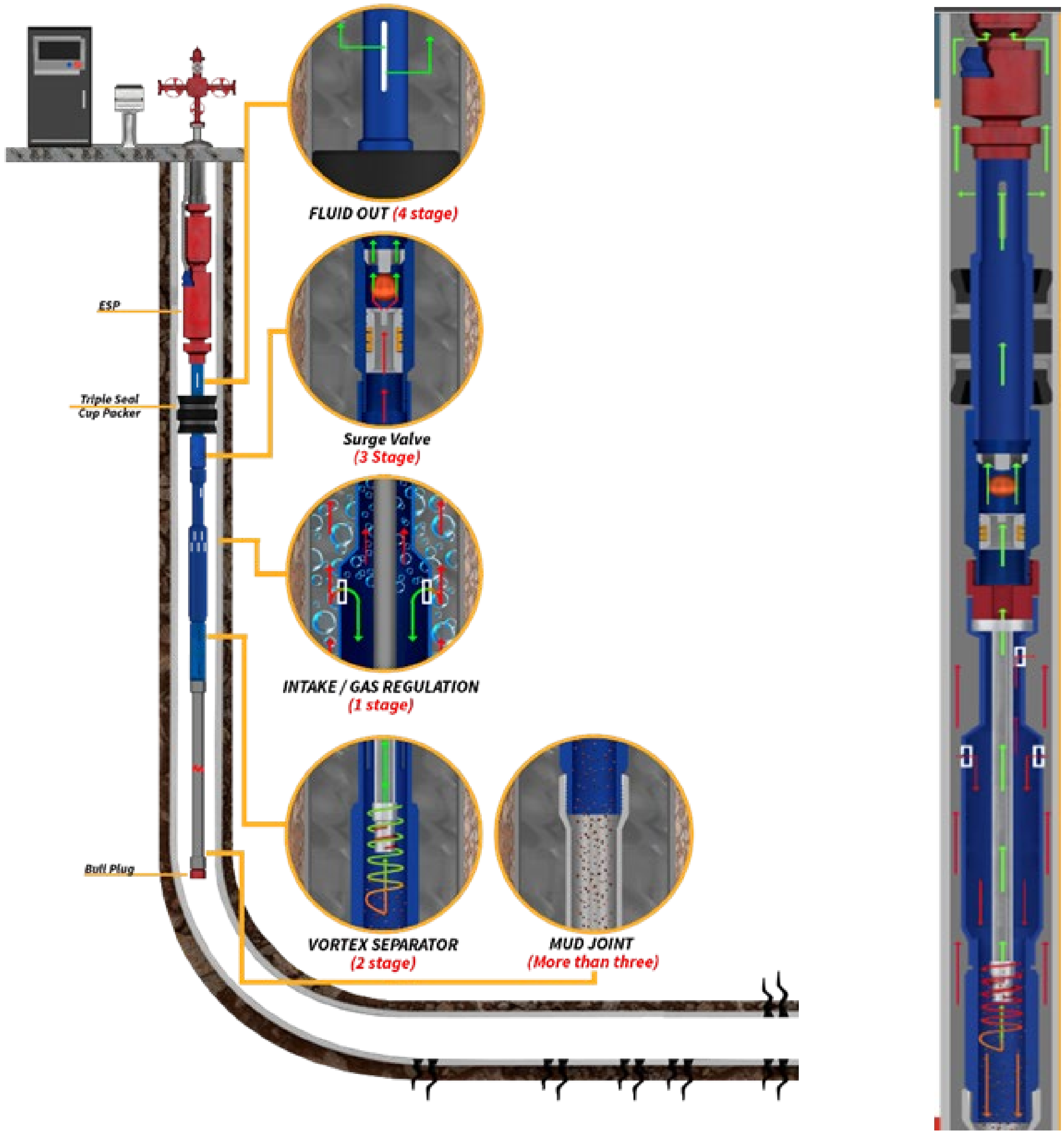

Figure 4 New ESP vortex regulator Sketch and Flow Path

This characteristic makes it possible to carry out chemical treatments, acids, or injection of any type of fluid towards the perforated zones. Figure 5 illustrates the flow path during production and the flow path during the fluid injection. The differential pressure to compress the outer sleeve inside the Surge Valve is 2,500 psi, so simply filling the annulus space can reach that opening pressure. For instance, in a well with 700 psi of bottom hole pressure, over 3,200 psi of hydrostatic pressure above the Surge Valve needs to be build up to compress the spring (~6,154’ of brine column in the annulus).

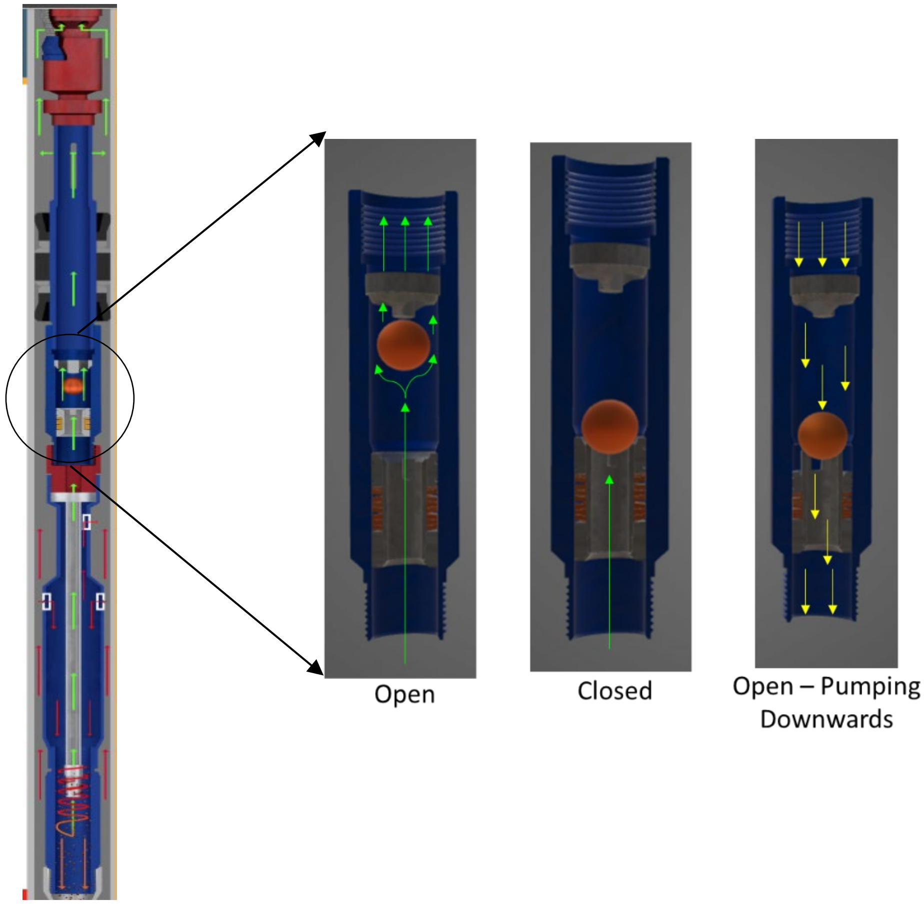

Figure 5 Surge Valve Operation

For wells with sand and gas problems, the ESP vortex regulator can be designed with a desander section that will filter out the sand particles at the centrifugal section preventing problems in the pump. In wells installed in deviated areas or just at the KOP, it is important to consider the use of centralizers or swivel tools to ensure correct centralization of the pump and eliminate excessive vibration in the motor shaft. Centralizers can be installed above the pump and below the pressurization and solids separation section. The swivel tool can be installed between the sensor and the outlet section and below the solid separation section.

<u>FIELD APPLICATION AND RESULTS</u>

The well A is located at the Midland Basin and completed in the lower-middle Sprayberry and had a history of multiple shutdowns, erratic current behavior, unstable PIP, and high motor temperature peaks, all caused by a combination of high GLR and low fluid rates (for ESPs). Figure 6.

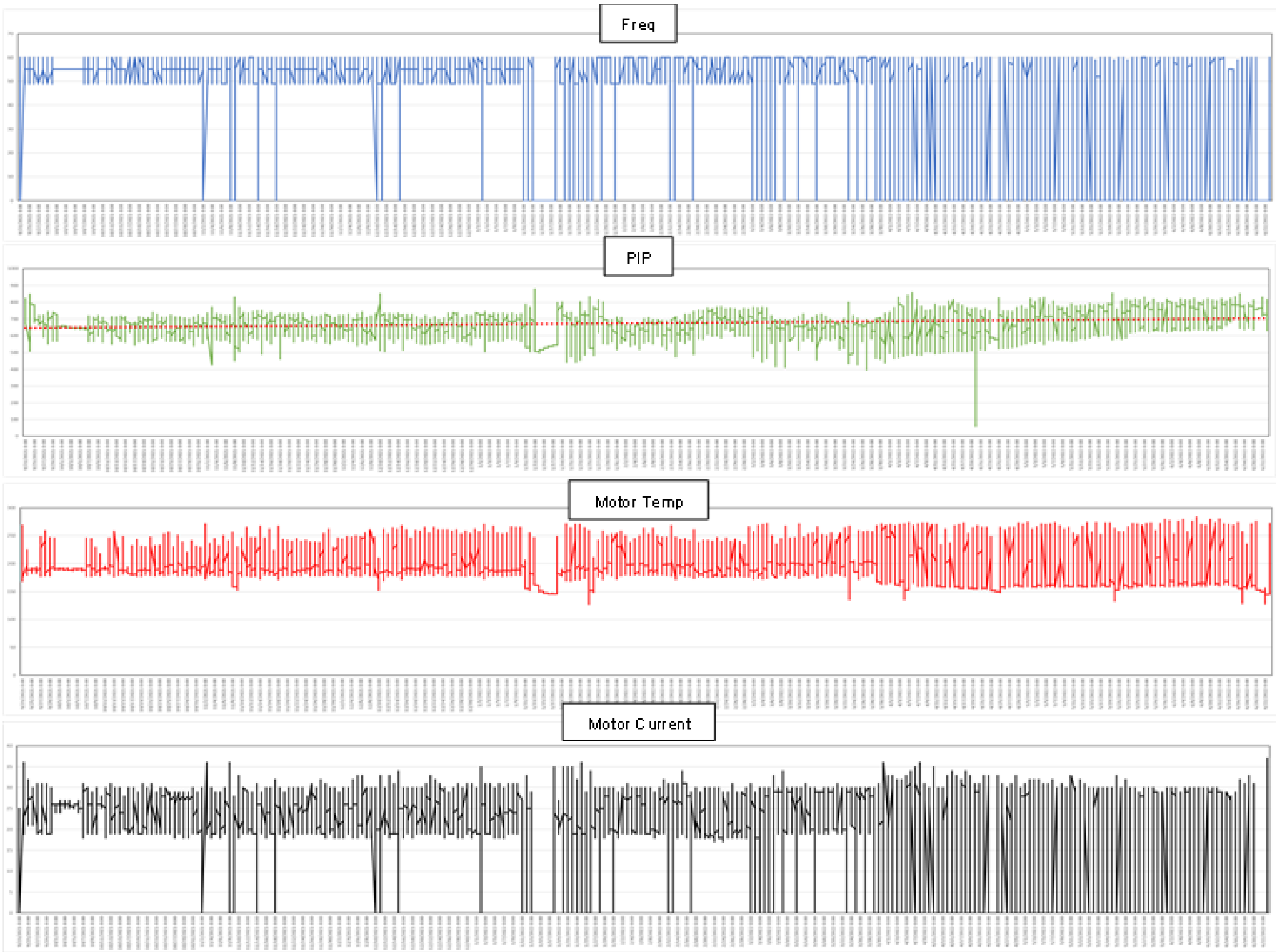

Figure 6 Pump Performance before ESP Vortex Regulator Installation

- 400 Shutdowns total
- 219 shutdowns in last 2 months before failure.
- Min PIP = 543 psi
- Min T = 178 °F
- Average PIP before May > 650 psi
- Average PIP after May 700 psi
- ESP was not able to deplete PIP.
- After shutdown on the 3/29/2022 PIP started to increase due to the multiple shutdowns
- Higher variation on motor temperature

The well produced a GLR of 3,000 SCF/STB with a liquid rate of 330 BPD (Table 1). The well was installed with 17.50 pump 400 series with 270 stages and a vortex gas separator plus a gas handler to deal with the gas issue but still there was a lot of interference as showed in figure 6. The well conditions and the pump design are summarized below. According to the simulation there was 86% of free gas at the pump intake.

Table 1 Pump design and well conditions

WELL CONDITIONS		
CASING 20#	5-1/2	IN
CASING DRIFT	4.653	IN
TUBING	2-7/8	IN
FLUID RATE (downhole)	766.37	BFPD
WATER RATE (downhole)	240.9	BWPD
OIL FLOW (downhole)	104.41	BOPD
OIL FLOW (surface)	89.1	BOPD
WATER FLOW (surface)	240.9	BOPD
GAS FLOW	531	MCFD
WCUT	73	%
GOR	5,959.6	SCF/STB
GLR	1,609.09	SCF/STB
PUMP INTAKE DEPTH	7,243	MD FT
FLUID PROPERTIES		
OIL GRAVITY	0.81556	
WATER GRAVITY	1.05	
GAS GRAVITY	0.84	
BOTTOM HOLE TEMP.	150	°F
BUBBLE POINT	1500	PSI

CONTROLLER
VSD 251KVA 262A-IN 302A-OUT 480V 3PH-SMARTEN
CABLE
CABLE #4 FLAT 232C 5KV
PUMP
400, 1750, 270 STAGES
GAS SEPARATOR
400 VORTEX 2-STG
GKX
UNBGAS
PROTECTOR
UPPER: DH_400/456_BPBSL
LOWER: DH_400/456_BPBSL
MOTOR
DH_456XT, 204HP, 2695 V, 48.5 A

Based on the given information, the diagnosis of the Well A was "Slug flow regime causing frequent pump shutdowns and instability of the pump operation." This diagnosis was determined using the Griffith and Wallis method, which is a common approach for identifying flow regimes in multiphase flows (Figure 7). Because of this phenomenon, the ESP was operating outside its design range and the performance was affected. To address this issue, measures limiting the production to reduce the drawdown and minize the risk of slugging may be considered, however, the production team look for a different approach by conditioning the fluid phases before they reach the pump.

Data			
Reference Pressure [PIP](psi)	650	Casing ID	4.778
Reference Depth [Pump Depth](ft)	7243	API	42
Reservoir Pressure (psi)	1800	SGw	1.2
Oil Production (BOPD)	89.1	SGg	0.84
Water Production (BWPD)	240.9	Liq Viscosity (cp)	0.8
Gas Production (Mscfd)	531	Gas viscosity (cp)	0.01625
Produced GOR (scf/stb)	5959.6	SGo	0.8156
Liquid Prodcution (BFPD)	330	Ap(ft^2)	0.1245
BHT (F)	150	Surf. Tension (lb/s2)	0.058

Results	
Relative Roughness	0.00037673
Reynolds(L)	59264
E/D	1.5854
Reynolds(g)	111551
Total Fluid Vel. (ft/s)	1.1993
Flow Regime	Slug

Figure 7 Well Diagnosis

The main objective with the installation of the vortex regulator was to allow the ESP to run longer and deplete the PIP without cycling (less downtime) and maintaining constant motor load. After the installation, the ESP has not had any shutdowns due to gas or motor temperature after the first 3 months, operation frequency started at 50 Hz and then increased to 55 Hz which allowed to deplete the PIP from 720 psi down to 465 psi, with casing pressure around 170 psi (Figure 8).

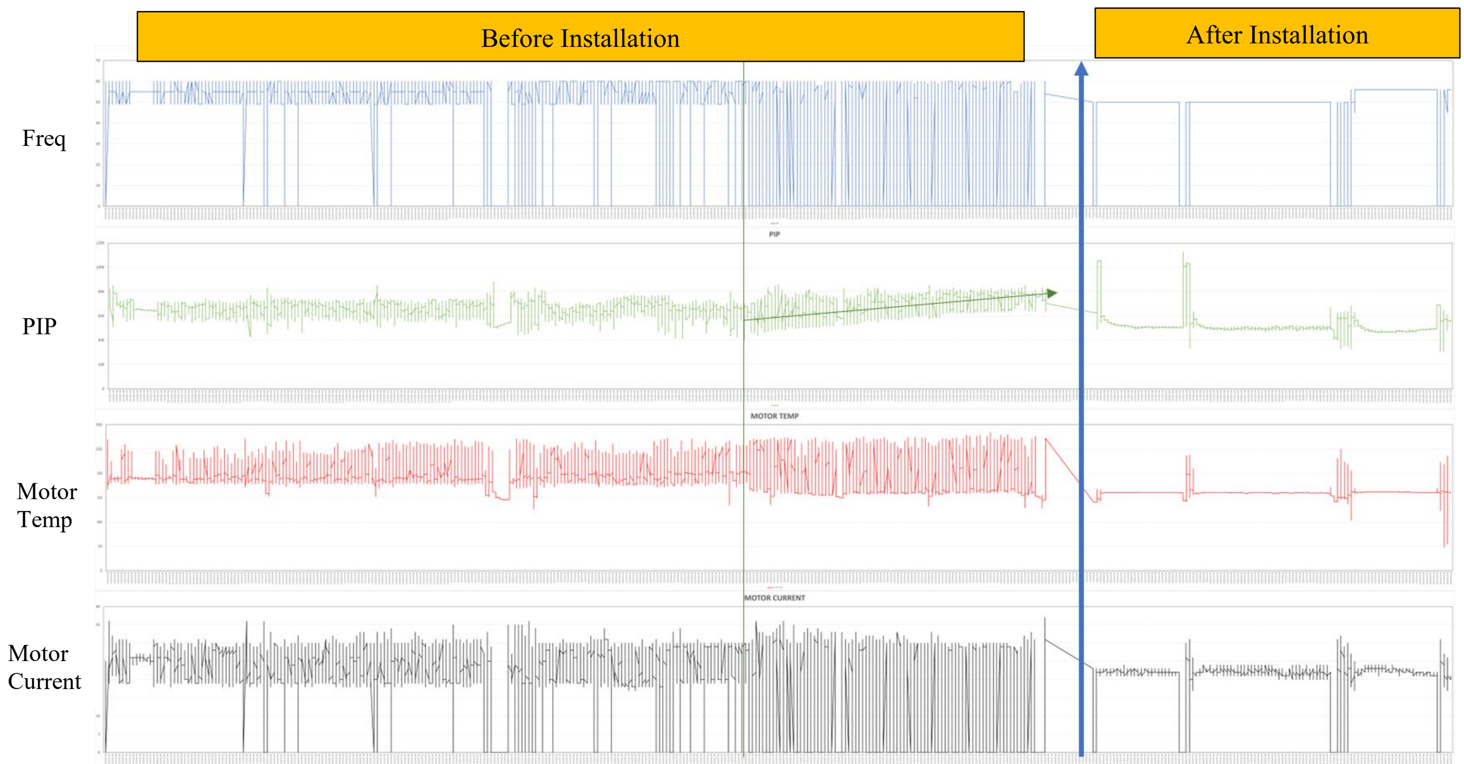

Figure 8 Pump performance after ESP vortex regulator installation

Table 2 summarizes the behavior of the sensor parameters before installation, and in May just before running the vortex regulator. Additionally, the variables are shown after the installation, divided into 3 periods: 1. before the first shutdown, 2. after the first shutdown, and 3. when the frequency was increased from 50 to 55 Hz. In general, a stable average behavior is shown while the PIP was considerably reduced compared to the average values before the installation.

Table 2 Pump performance before and after the installation of the vortex regulator

	Before Install	**Before install - after May/2022 (while operating)**	**After Install 1st period**	**After Install 2nd period**	**After Install Freq changed 50 to 55 Hz**
Min PIP (psi)	543	495	499	473	458
Avg PIP (psi)	650	700	518	500	482
Min T (F)	178	186	159	159	160
Avg T (F)	242	203	159	160	160
Motor Current (A)	19 - 29	19 - 30	20 - 24	20 - 24	20 - 24

Zooming in the pump performance after the installation these are the main facts identified from July to October 2022 related to the pump intake pressure.

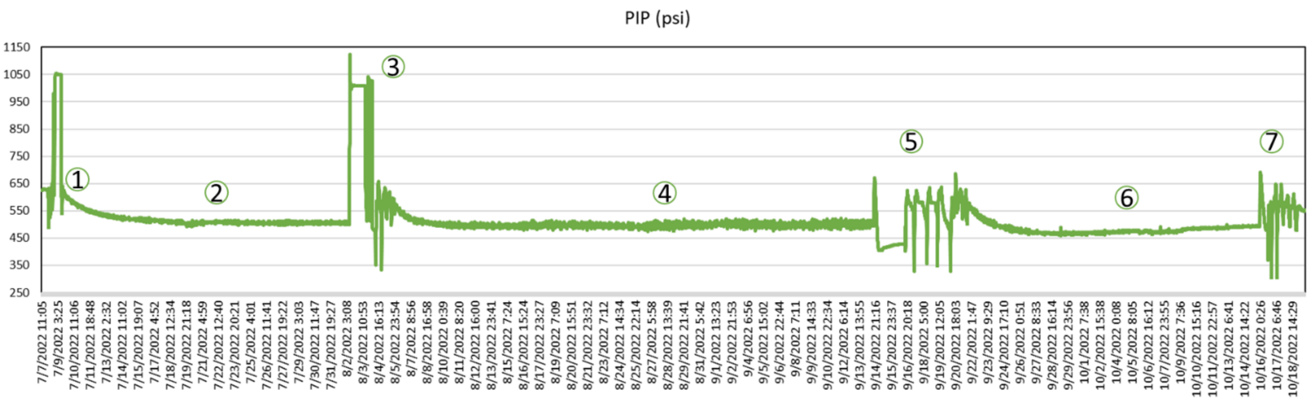

Figure 9 Pump intake Pressure after Installation- Update with recent data

(1) 1 day to break 600 psi barrier in normal operation
(2) One month without any shutdown - Min PIP 499 psi & Avg PIP 518 psi
(3) Shutdown due to facilities
(4) Min PIP 473 psi and Avg PIP 500 psi
(5) Shutdown due to storm
(6) Freq increased from 50 Hz to 55 Hz – Min PIP 458 psi & Avg PIP 482 psi
(7) Shutdown due to storm

Regarding the functioning of the Surge Valve and how it looks like in the sensor parameters, figure 10 shows the dynamics between the hydrostatic and bottom hole pressure. Because the sensor data prorated the data every 15 minutes so oscillation between data points may look severe, but it is actually a gradual process to go from open to close inside the Surge Valve. Every time the ball seats and close the flow from bottom up the PIP (Pump Intake Pressure) decreases, on the other hand, when the valve opens the PIP increases slightly until the hydrostatic pressure is higher than the bottom hole pressure.

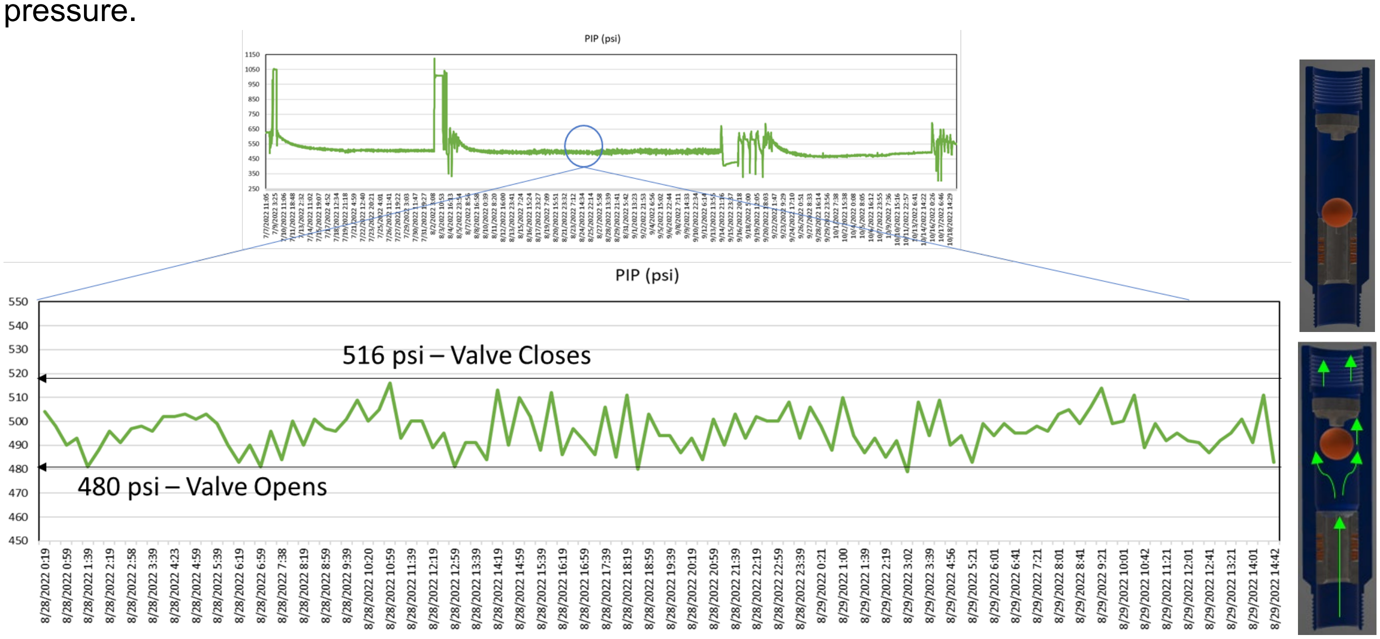

Figure 10 Surge Valve Operation

Finally, comparing the oil production loss before and after the installation, there was a significant improvement leading to practically eliminate the production losses caused by gas issues. Figure 11 shows the total volume of oil and the lost opportunity due to non-productive time and the gas limitations before the installation and the results after the installation in the same period. The total oil production lost before the installation was 7,350 BOPD and the income lost was around US $661,500.00.

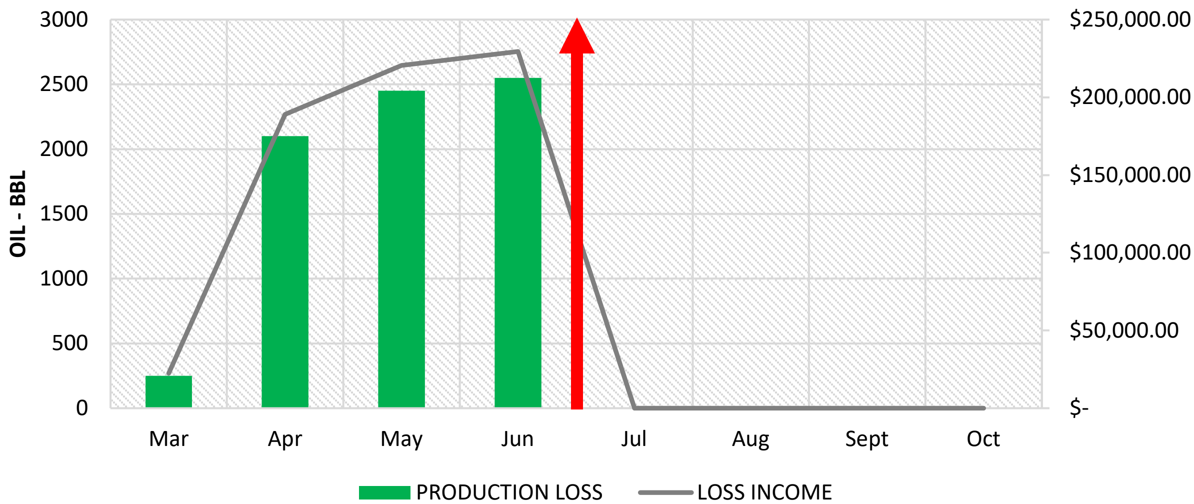

Figure 11 Well Performance before and after - Lost opportunity

The well was pulled on February 2023 because of grounded ESP and the vortex regulator was inspected and re-run replacing only the slotted intake section due to corrosion. Figure 12 shows the historical behavior of the GLR and oil production. The GLR changed because of the tool mechanism regulating the gas production and the oil production increased around 45 BOPD after the installation. The first production test after the reinstallation in February 2023, shows a production in accordance with the design of the pump, so for now there are no production losses due to gas problems.

After the installation these are the main conclusions obtained by the operator:

- Vortex Regulator was capable to control the cycling on the well due to gas by reducing the number of shutdowns.
- The ESP had 387 shutdowns in 2022 before the installation of the Vortex Regulator technology, after the installation 0 shutdowns due to gas up to date.
- After the installation PIP was drawn from 700 psi down to 458 psi, which is the pumping off point.
- Motor temperature has decreased to a healthier operational value from erratic behavior with an average of 203 °F down to a constant motor temperature of 160 °F. In terms of stability, before the installation the motor temperature had a standard deviation 24 °F while after the installation the standard deviation has been 6.5 °F. This stable behavior will have a direct impact in the seal's run life and of course in the motor's run life.
- Oil production is up 41 BOPD on the last production test in last run.
- Oil Production up 60 BOPD in comparison with ESP Cycling.

- This technology can provide the ESP longer use specially under high GLR conditions.
- Gas handling technology reduce downtime protecting the integrity of the motor and extending its useful life.

CONCLUSIONS

- This paper has presented an advanced gas regulator system that has been designed and configured to extend the run time and stabilize operational parameters of ESPs. The performance showed in this application has expanded the range of applications where the ESPs can be considered as feasible to maintain stable production.

- The understanding of the conditioning of the fluid to adapt it to the limitations of the pumping system has been one of the most important conclusions of this document. Through the dispersion of the gas bubbles within the liquid phase, it was possible to obtain a more optimal performance of the electrical submersible pumping equipment in the well analyzed in this document and in subsequent wells where this technology continues to be evaluated.

- The evaluation of the limit and applicability of this tool is considered as an important factor by the authors. By doing so, we can better understand the tool's capabilities and limitations, and use it more effectively in the future. Overall, the expansion of the tool's use and quantification of its limitations will enable us to make more informed decisions and drive greater success in future installations.

- Based on the lessons learned collected so far and on the analysis of the tool's operating mechanisms, different alternatives have been proposed to improve its performance in certain conditions. One of them is the increase in the volume of liquid stored in the section under the packer, extending the internal dip tube and deepening the suction point of the gas/liquid mixture. In the same way, the size of the propeller to achieve a better dispersion of the bubbles continues to be evaluated to find a more direct relationship between the physical effect and the volume of gas.

- Other types of alternatives considered by the engineering and the production team are changing the setting pressure in the surge valve of the regulator to install it in wells with high bottomhole pressure. This approach will work in new wells installed with ESPs where the depletion in PIP will eventually cause gas issues in the pump.

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