CONTROLLING GAS SLUGS IN ESP USING A NEW DOWNHOLE GAS REGULATOR: CASE STUDIES

S.R. Vyas, L.A. Guanacas, G. Gonzalez, and C.A. Portilla
Odessa Separator Inc.

ABSTRACT

Gas production is one of the main problems on ESP systems; causing premature failures and low efficiency, these are the reasons why many companies have developed several solutions to separate gas before reaches the pump. To solve this problem a New Downhole Gas Regulator has been developed to avoid large amounts of free gas flowing directly into the pump intake. This system regulates the amount of gas ingested by the pump so it will make easier for the pump stages to lift a fluid with a higher density (Less amount of gas in the multiphase flow). The system was designed to use the free gas flowing upward with the liquid to re solubilize the gas into the oil and produce the fluid with the lowest GOR and highest Rs possible. The ESP's Downhole Regulator was designed based on each well conditions to maximize its efficiency.

INTRODUCTION

The Wolfcamp shale and Lower Spraberry are oil and gas formations extended along the Permian Basin1 and developed since the early 20th century with vertical wells, however, in the last two decades, the focus has changed looking for greater production through horizontal wells with greater production zones. These formations can be found in the Midland, Delaware, and Central basin platforms at different depths. According to information on the USGS2, just in the Midland basin, Wolfcamp contains around 20 billion barrels of oil, 16 trillion cubic feet of associated natural gas, and 1.6 billion barrels of natural gas liquids distributed in Wolcamp A, Woldcamp B, Wolfcamp C, and Wolfcamp D.

The wells installed with the new technology were drilled and completed in Midland, Martin, and Howard County in the Midland basin (Figure 1). The production profile of the wells produced in this area is characterized by a high initial fluid production with high water cut, low GLR, and high sand production because of the flow back of the frac sand. The conditions change rapidly because of the well depletion using ESPs in the initial completion. Typically, in 3 or 6 months, the profile will pass to a steady fluid production with medium to low water cut and high GLR. At this point, the sand production will depend on the type of producing formation and the consolidation degree of the rock. Figure 2 represents the profile described previously, the initial production was 5,927 BFPD with a water cut of 72% and GLR of 232 SCF/STB. After 3 months the well was depleted, and the gas production rose to 0.5 MMCFD with a steady production around 1000 BFPD. The behavior was not maintained due to the interference of a child well but after the communication between both wells was balanced, the well adopted the depletion rate expected with a high GLR (> 1000 SCF/STB) and a steady production rate.

This kind of profile and the use of ESPs bring common problems such as gas and low volumetric efficiency in the pump. Several operators in the Permian basin face these problems and use the traditional solution such as gas handler in the ESP or mix pump stages to compress the free gas inside the vanes of the impellers, however, when the percentage of free gas at the pump intake is significantly high (>80%), it is difficult to obtain satisfactory results. The new technology introduced in this paper and proved through multiple applications strikes this problem before it reaches the pump intake and forces the gas slugs to disperse into the liquid modifying two characteristics of the fluid: the solubility of the gas and the flow regime.

GAS SLUGS PROBLEM DESCRIPTION

As a result of the massive implementation of horizontal wells due to their advantages, the problems for gas slugs were also generalized along the Permian basin. The flow regimes in a horizontal well are classified as stratified smooth, stratified wavy, slug, elongated bubble, dispersed bubble, and annular. Figure 3 shows the representation of the 6 types of flow regimes and the relation with the liquid and gas velocity in the horizontal section of the well. For two-phase gas-liquid flow in a horizontal well, the most likely flow regimes for toe-up and toe-down wells are stratified and slug flow, respectively. For stratified flow, gas flows on the top portion of the well, and liquid flows on the bottom portion of the well. The gas-liquid interface remains flat for the low gas and liquid flow rate. The interface becomes a crescent shape as gas and liquid flow rates increase causing the liquid phase to climb up along the periphery of the pipe. The liquid level in a stratified flow regime increases as the flow inclination angle increases and decreases otherwise.

Intermittent flow and elongated bubble flow occur when the in-situ gas flow rate is low and becomes slug flow when the in-situ gas flow rate is high. Both slug and elongated bubble flow can be characterized as an alternating flow between the liquid phase occupying the entire flow cross-sectional area and the liquid film that has a gas bubble flow on top. In the case of slug flow, the liquid phase entrains some gas bubbles inside but, there is no gas bubble entrained inside the liquid phase for elongated bubble flow. When the fluids reach the vertical section of the well the flow regimes are similar to those in the horizontal section except for the stratified flow because there is no lower side of the pipe which the densest fluid prefers. This fact implies that when the slugs are created in the horizontal section, they will move through the casing, passing for the curve to the pump that is installed in the vertical section, so despite the fluid column accumulated in the well, when the flow regime is ruled by slugs, the pump will receive frequents amounts of free gas that will degrade its performance (Figure 4). Additionally, we are including a video of a lab test made with Texas Tech University to understand the gas slugs behavior downhole from the horizontal to the vertical path.

When the free gas enters the impellers, the performance of the pump stages is highly affected; first, we will notice a reduction of the head developed by the pump compared to the manufacturer curve. Second, the area available for the liquid is reduced because the gas is expanding and occupying space inside the vanes of the impeller. Because the gas phase is lighter than liquid, it tends to move on the low-pressure sides of the impeller vanes, whereas liquid flows at the high-pressure sides. Small gas bubbles are pushed by the liquid flow toward the diffuser; this is the situation when low amounts of gas enter the pump. As explained previously this is bubble flow and dispersed fine bubbles are moved by the liquid without any slip between the phases. As free-gas volume at the pump intake increases and more small bubbles enter the impeller, the bubble flow is now transformed in slug as a result of the coalescence of the gas bubbles. When the size of these large gas bubbles reaches a critical value, gas becomes stagnant at the impeller intake causing further accumulation of bubbles and formation of a gas pocket. Gas pockets cause unstable operation of the pump stage called surging characterized by the sudden discharge of liquid and gas slugs from the pump and leading to severe equipment failures. If these pockets are not transferred by the liquid flow toward the impeller discharge at a sufficient rate, they will grow in size and can finally completely block the liquid flow through the impeller, and gas lock occurs4. Figure 5.

Summarizing, since the drilling and completion, the well starts with an initial high fluid production, high water cut and low GLR, eventually this turns into a steady production with medium to low water cut and high GLR until the flow reaches the slog pattern flow, then the gas accumulation in the impellers will lead to gas lock and finally to the ESP failure. Of course, before the ESP fails, we need to mention the low productivity of the well because the phenomena described previously that will end in drastic problems like a broken shaft, motor burn, motor grounded, seals damaged, etc.

FIELD EVALUATION: DIAGNOSTIC

The evaluation of the production conditions for the field where the technology was tested was carried out in cooperation with the operating company. The first term was to define the production profile of the well and its behavior over time. With this information it seeks to choose between two aspects:

- Install the Vortex Regulator from initial completion
- Install the Vortex Regulator when redesigning and replacing the pump

However, these two options were needed if the field was having gas problems. This analysis was be carried out based on the production profile determined by the production engineers. The profile is shown in Table 1. According to the depletion curves for the field based on previous drilling campaigns, the wells would reach a stable production after 3 months with an approximate GLR of 2000 SCF/STB. Because the dispersion of the fluid production data was not considerably wide, it was possible to design a pump for the full range. After determining the profile, the evaluation focuses essentially on the properties of the production fluids to analyze the behavior of the flow in the vertical section of the well where the pump is installed. The collected data is shown in table 2. Additional information for the analysis such as gas solubility (Rs), volumetric factors, and gas compressibility factor (Z) was determined based on the pump intake pressures simulated during pump design for each stage of the profile. The results of the calculation are summarized in table 3. The diagnostic of the problem is made based on two criteria: the presence of the problem and the severity of the problem. The presence of the problem is a qualitative measure that refers to a yes or no, the second criterion is a quantitative measure and is related to damage to the short term that can generate the problem. In our case, the qualitative variable would be the flow regime that, although it is determined numerically through correlations, will give us the type of flow in the vertical section of the well, on the other hand, the quantitative variable is the percentage of free gas at the entrance of the pump that as previously reviewed is considered severe for cases above 40%5. The results obtained for the 4 stages of the production profile are shown in Table 4.

The final evaluation shown in table 4 reveals that at the beginning of the production period, there is a bubble flow with a percentage of free gas of 7%, however, when reaching the fourth week, the reduction in pressure releases gas in solution that changes the behavior of the flow to slug, which although it does not represent a problem, quickly turns into a severe issue reaching a percentage of free gas of 88% at the pump intake. At this point, it is important to analyze whether having a gas separator in conjunction with the pump's gas handler is sufficient to handle 88% of the fluid represented in gas and only 12% represented in liquid (figure 6). It is in this small analysis where it is evident why although measures are taken in the design of the pump, the results are not as expected, and the performance of the pump is not optimal. In general, the situation described above represents the state of the entire field and the problem that each of the wells drilled will face. It would become worse as the field becomes depleted and the pressure in the new wells lowers along with the start of slug fluid formation.

GAS HANDLER: VORTEX REGULATOR

The Vortex Regulator is a device developed to control the multiphase nature of fluid flowing in the vertical section of the well, where gas flows independent of the liquid phase and therefore more quickly reaches the inlet of the pump. As explained in the previous sections, this phenomenon causes multiple problems and reduces the production of wells installed with ESPs.

This new device is installed below the pump sensor and consists of 4 sections as explained in figure 7. The inlet section, isolation section, pressurization and separation of solids section and the outlet section. The 4 sections are combined to create a unique effect near the pump inlet, delivering an almost homogeneous, single-phase mix of production fluids to the pump. The gas slugs flowing with the liquid are initially retained by the isolation section and accumulated in the neck above the inlet section. In this area, the first mixture of the liquid with the gas is produced when both slugs collide and enter through the slots of the system. The gas slug is dispersed becoming an elongated bubbles flow. The above mixture enters the device and flows downwards, pressurizing the mixture and causing the smallest gas bubbles to re-solubilize and disperse in the elongated bubbles flow created outside the device. The bubbles dispersion is enhanced with the help of the solids separation section where a helix generates a centrifugal force in the fluid, dissipating the bubbles and separating the solids. The homogenized fluid mixture turns into a bubble flow with small and resolubilized bubbles flowing with the liquid. The re-solubilization process of the gas bubbles is optimized by a smaller inner pipe connected to the top of the helix. Over there, the pressurization reaches its maximum value and then the greatest increase in the solubility of the gas in oil is obtained. Table 5 shows how the change in Rs is in this section of the tool and shows how, in addition to the dispersion of the free gas bubbles, there is a re-solubilization of the gas phase within the liquid phase.

The inner pipe is in charge of communicating the sections above and below the packer and it will take the homogenous fluid to the outlet section above the packer (Figure 7). The homogeneous fluid mixture is discharged into the annular fluid column. The change in diameter will release a portion of the resolubilized gas and the amount of gas released is related to the size of the casing and the amount of fluid in the annulus, however, this volume of free gas will not be enough to form a slug flow. The almost homogenous mixture will flow upwards to the pump where the gas handlers and gas separators will create a combined effect that would rid the pump of the significant effects of free gas within the impellers. For the proper design of this device in each well, it is important to consider the following points:

1. Isolation section size. This size is chosen based on casing diameter and weight, depth, and flowing well pressures.
2. The isolation cup material is selected based on temperature and gas and fluid composition
3. The distribution of the slots in the inlet section should guarantee a sufficient open area for the expected fluid volume but be able to disperse the gas slug
4. The diameter of the internal pipe depends on the required pressurization. At higher % of free gas, greater fluid pressurization should be sought
5. The helix is designed for the amount of fluid and the severity of sand production. These two factors are used to choose the pitch area. The device must be connected just below the sensor, as close as possible to the pump intake

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 pump 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</u>

Since the start of the development of the field located in the Midland Basin in the Wolfcamp A and lower Spraberry, gas has been a problem for the production performance. Figure 8 shows the behavior of the first well completed in June 2018. The initial pressure was 4000 psi and stabilized at 1000 psi after 4 months of production. From the start of production, the gas strongly affected the motor cooling. While the motor maintained temperatures between 208 °F and 260 °F, the fluid had a temperature between 161 °F and 190 °F, indicating that the transfer of heat from the motor to the fluid was not constant and was affected by the slugs of free gas flowing in the vertical area of the well6. As the intake pressure dropped, the interference in the operation increased so the PIP had to stay at a stable value. In 2019, the wells drilled during 2018 presented the same behavior, while the wells drilled in 2019 had an intermittent performance from the beginning of their production, mainly because the production activity and wells spudded in the past year (Figure 9). This new condition, with a more depleted field, limited the decrease in PIP due to gas interference in the pump. This intermittency in the operation of the pump and the low fluid recovery caused the analysis of the field conditions to determine what the problem was and how to optimize the operation of the pump.

After reviewing the field diagnosis and evaluating the specific behavior of the wells spudded until the second quarter of 2019, it was decided to start the implementation of the Vortex Regulator from the third quarter of the year, for both new wells and wells that failed from that point moving forward. The design of each well was independently evaluated to decide each of the criteria related to the previous section. In general, the design considered the mechanical state of the well, expected production conditions, and severity of the problem. The pump would be installed in the vertical section of the well while the tail joints and a downhole chemical treatment would land into the curvature of the well so centralizers were installed along with the tail joints. Figure 10 shows the deviation survey of the well with the location of the BHA.

RESULTS

The implementation of the new technology in the field started in the third quarter of 2019 and to the first quarter of 2020, 54 wells were installed between new and re-installed wells due to failures or pump changes. Figure 11 summarizes the wells installed and the run time of each one. Within the wells installed to date, 3 wells were pulled due to failures related to pump issues. On these 3 wells, the isolation sections were replaced to ensure the proper isolation of the pump intake. At the beginning of 2020, a fourth well was pulled and high production of sand was identified, which generated sand cutting problems in the device, so the solids separation section was replaced with higher resistance metallurgy to support the erosion of the sand. In terms of adjustment, this has been the major change made and along with the use of centralizers have been the lessons learned during the performance of the wells.

The performance evaluation of the tool was made based on the parameters of the ESP sensor. For new wells, shutdowns, variations in motor current, variations in voltage, and the difference between motor and fluid temperatures were analyzed. Figure 12 shows the sensor data for a well completed from the beginning with the Vortex Regulator. In general, the sensor parameters remained stable during the analyzed period. The frequency was kept constant at 45 Hz while the motor and fluid temperature did not have significant changes and remained around 160 °F. This similarity in temperature indicates an efficient heat transfer between the motor and fluid, so there was not free gas flowing around the motor. The motor current and the voltage show a stable and constant behavior, that is why the presence of solids and gas interference is ruled out. Normally, gas and/or solids inside the pump stages generate large changes in the amount of power required by the motor. Compared to the behavior of the wells analyzed in the previous section, the performance of this well maintains a much more stable trend with fewer shutdowns.

For wells intervened and re-installed with the Vortex Regulator, the performance was evaluated by comparing shutdowns, variations in sensor parameters before and after the installation. Figure 13 shows the behavior of a well analyzed under this criterion. The well was drilled in April 2019 and it was re-installed with the Vortex Regulator in September 2019. Prior to pulling the well, when the PIP fell below 1500 psi (red dash line), the motor began to show variations in the current. Initial variations were slight but as the PIP dropped down the variations became shutdowns. Figure 14 shows the behavior of the pump just before pulling. From July 13, 2019, to August 13, 2019, 25 shutdowns and an increase in the motor temperature were reported. Due to the poor performance, the operator decided to pull the well and install the Vortex Regulator. After installation, the change in the behavior of the pump was remarkable. Despite operating below 1500 psi, there was no intermittent or significant change in sensor parameters. Likewise, the motor and fluid temperatures did not register changes and remained at close values. In March 2020, several wells were shut-in due to the situation of the oil market and then there was pressurization in the well that caused changes in the trend, however, these changes were stabilized with the regulation of the frequency of the pump.

CONCLUSIONS

- Flow regime characterization is a very useful tool to identify problems and generate mitigation plans that reduce adverse effects on production. The information of the diagnostic model can be done for the entire field as shown in this paper or divided by regions depending on the formations, formation pressure, pad or even for each well and thus increase the level of detail and reduce the uncertainty.
- High formation pressure does not guarantee a single-phase flow in the well. Bubble pressure, field depletion curve, and percentage of free gas calculations at the pump intake should be considered to determine at what point free gas problems can occur. This is another option to create the best ESP design from the beginning of the production life of the wells.

- Wells with slug flow in the vertical section are highly susceptible to poor pump performance. Even adding gas separators and handlers to the pump does not solve the problem in cases where the percentage of free gas exceeds 40%.
- To deal with slug flows, the slug must be retained and dissipated into the liquid phase, in this way, the flow will pass from a slug to an elongated bubble flow. Pressurizing and centrifuging the flow helps to completely disperse the gas bubbles in the liquid and re-solubilize a fraction of the free gas. After this process, a bubble flow is obtained, and it can be easily managed by the pump.
- The use of the vortex regulator in both new and re-installed wells radically improves pump performance. The operating parameters were kept stable; therefore the equipment's run life was greater.

<u>REFERENCES</u>

- https://www.shaleexperts.com/plays/wolfcamp-shale/Overview
- Gaswirth, S., et a;. “Assessment of undiscovered continuous oil resources in the Wolfcamp shale of the Midland Basin, Permian Basin Province, Texas, 2016”. USGS, November 2016
- Watson, M., Panacharoensawad, E., and Gonzalez, G. “New Gas Anchor for Horizontal Wells”. SWPSC 2018. Lubbock, Texas.
- Takacs, G. “Electrical Submersible Pump Manual”. Second edition. Elsevier. 2018
- Camilleri, L., Brunet, L. Segui, E. “Poseidon Gas Handling Technology: A Case Study of Three ESP Wells in the Congo”. SPE 141668. Manama, Bahrain, 2011.
- Gonzalez, G. Loaiza, C. “Improving Gas Separation in ESP for Unconventional Wells in 5-1/2 Casing Case Studies in the Permian Basin”. SPE-194418-MS. The Woodlands, Texas, USA, 2019.

Table 1 Production profile of the field

	Fluid Production (BFPD)	Water cut (%)	GLR (SCF/STB)	Time (weeks)
Stage 1	5,000	90-99	100	1
Stage 2	3,500	80-85	300	4
Stage 3	2,000	70	1,000	9
Stage 4	1,200	55	2,000	12

Table 2 Information gathered

API	38	°
SGw	1.12	
SGg	0.89	
Liquid Viscosity	0.8	cP
Gas Viscosity	0.016	cP
BHT	160	°F
Static P	2,500	psi

Table 3 PVT parameters calculated

	PIP (psi)	R_s (SCF/STB)	B_o (bbl/STB)	Z
Stage 1	2,500	896.50	1.53	0.70
Stage 2	1,800	598.60	1.35	0.73
Stage 3	1,000	298.60	1.19	0.80
Stage 4	600	164.4	1.12	0.87

Table 4 Field diagnostic

	Flow Regime	%Free gas at the pump intake	Well Classification
Stage 1	Bubble	7	Slight
Stage 2	Slug	16	Slight
Stage 3	Slug	65	Severe
Stage 4	Slug	88	Severe

Table 5 Effect of the Vortex Regulator on the Rs

	wo/Vortex Regulator	w/Vortex Regulator
	R_s (SCF/STB) *	R_s (SCF/STB) *
Stage 1	896.5	921.7
Stage 2	598.6	613.1
Stage 3	298.6	311.6
Stage 4	164.4	184.8

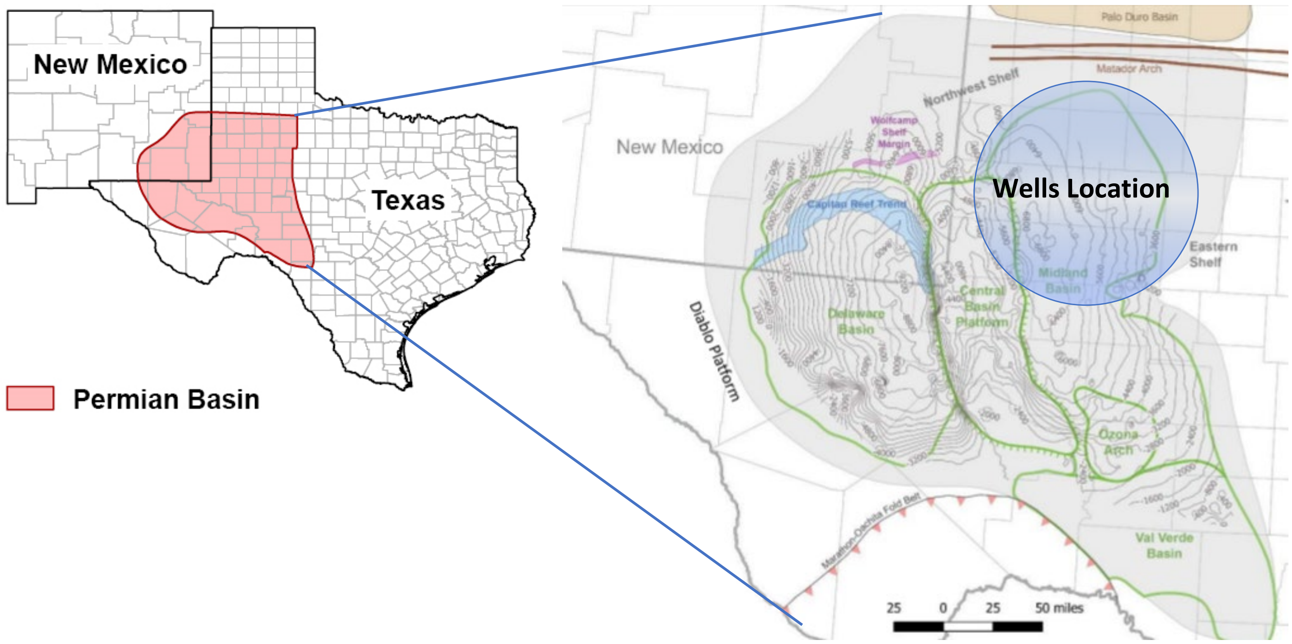


Figure 1 Wells Location (U.S.Energy Information Administration based on drilling Info)

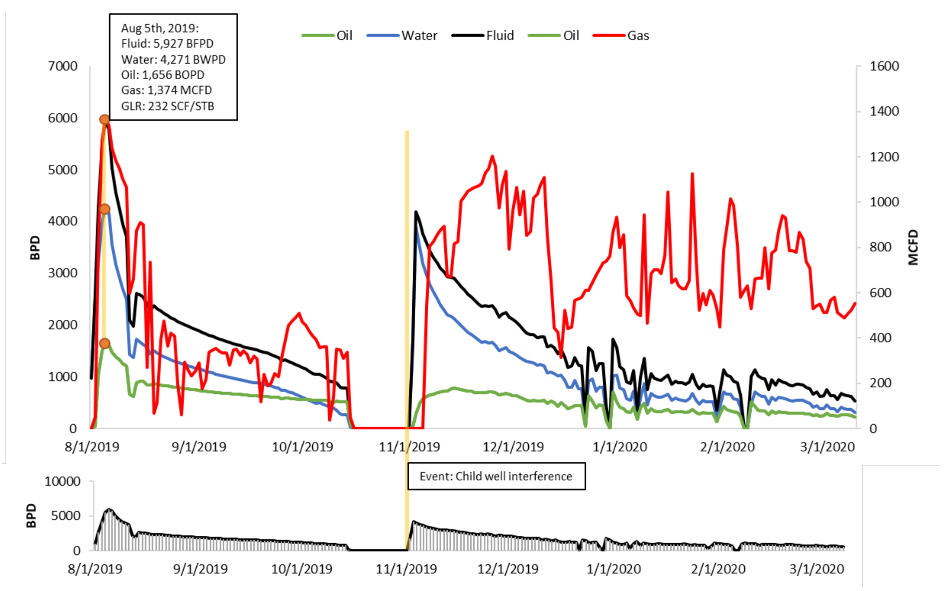


Figure 2 Production profile, Midland basin

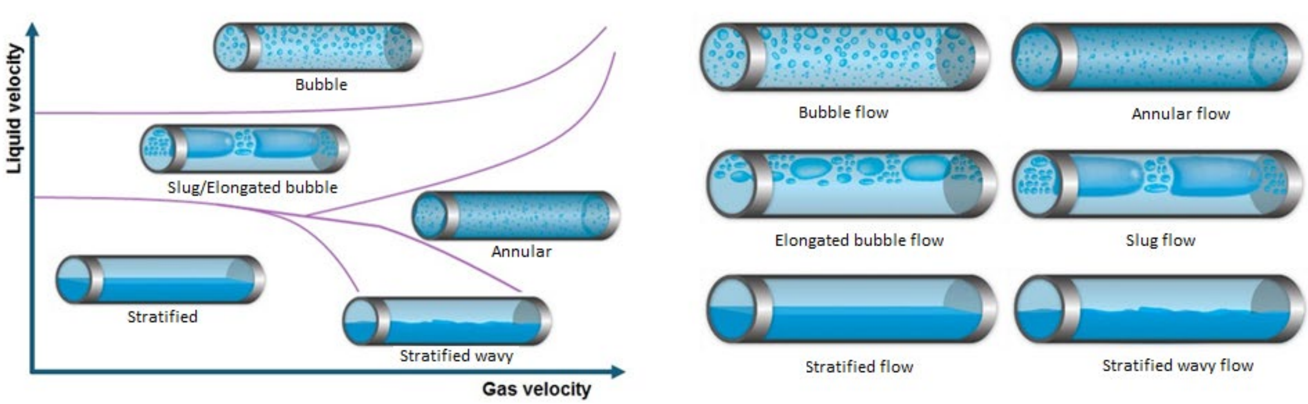
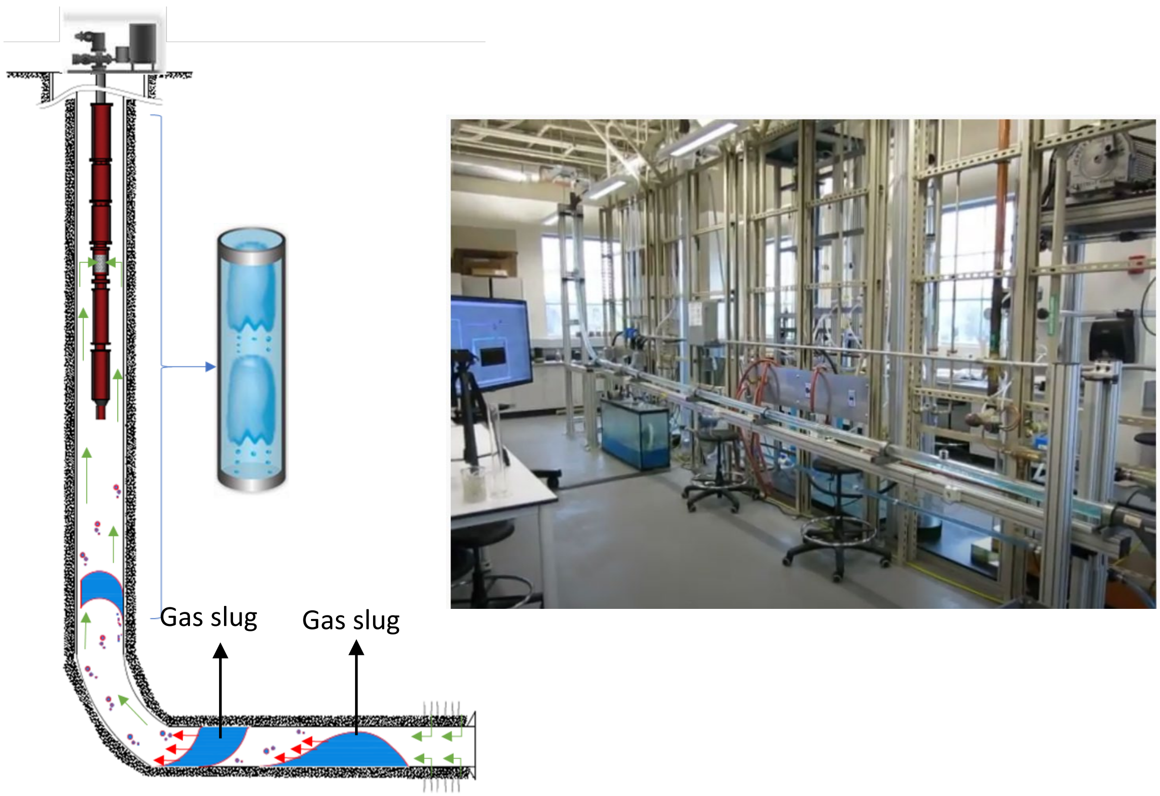


Figure 3 Flow regimes in horizontal pipes (Source: Pipe flow 2)



https://www.youtube.com/watch?v=MKHpCggHtLc&feature=youtu.be

Figure 4 Gas slugs flowing to the pump

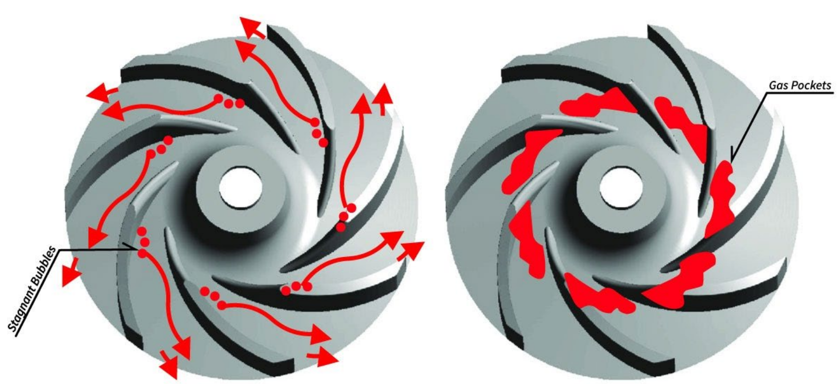


Figure 5 Gas effect on centrifugal pumps

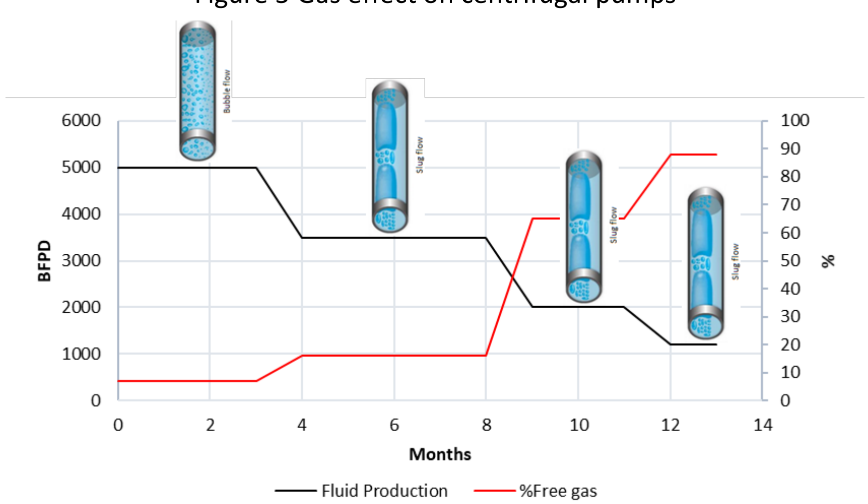


Figure 6 Field behavior

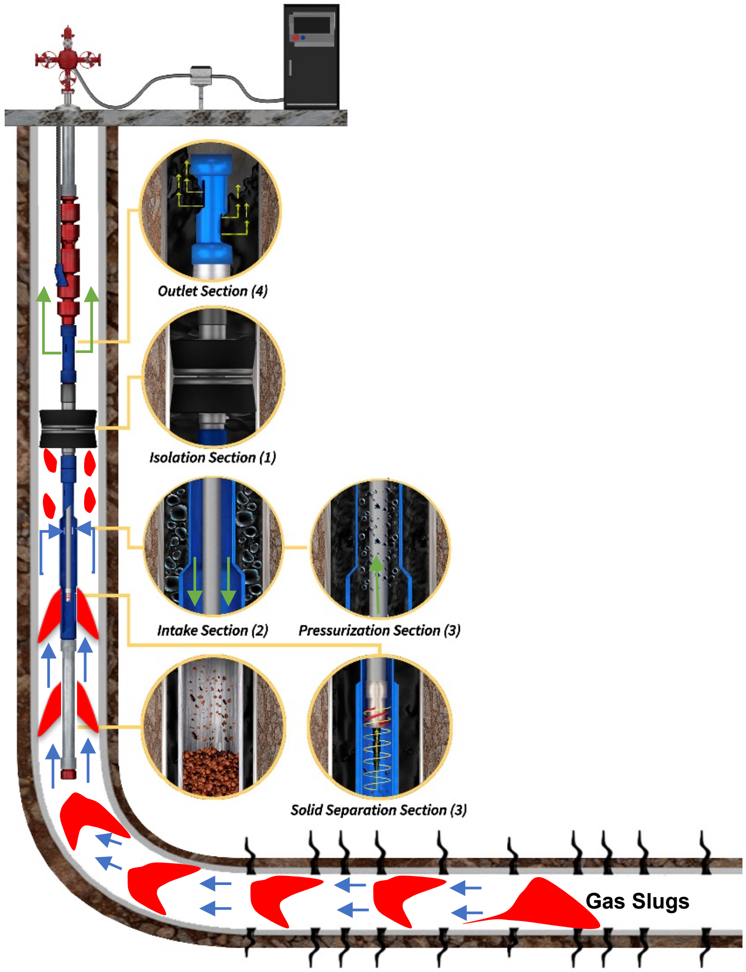


Figure 7 Vortex Regulator Sketch and flow path

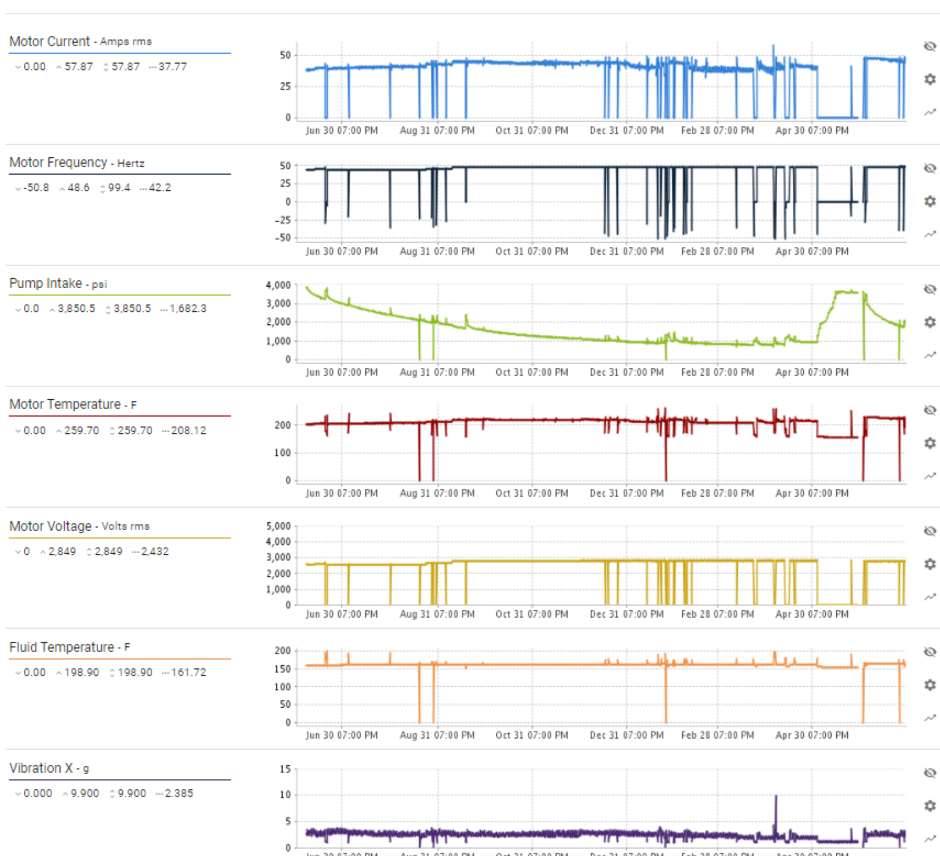


Figure 8 Well completed in 2018

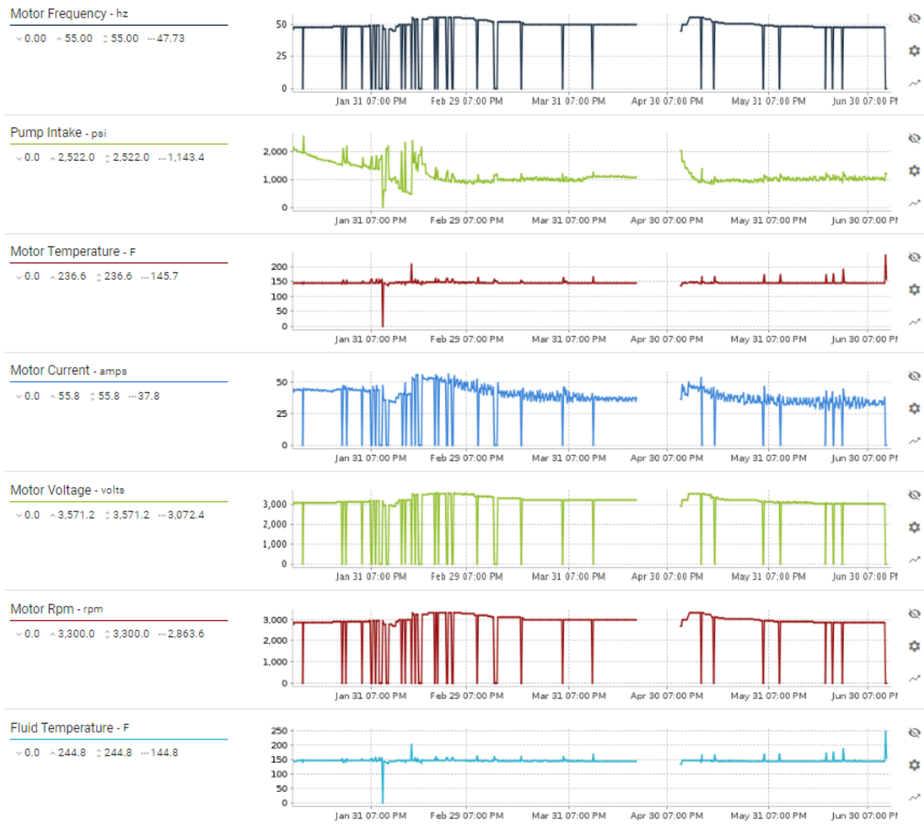


Figure 9 Well completed in 2019

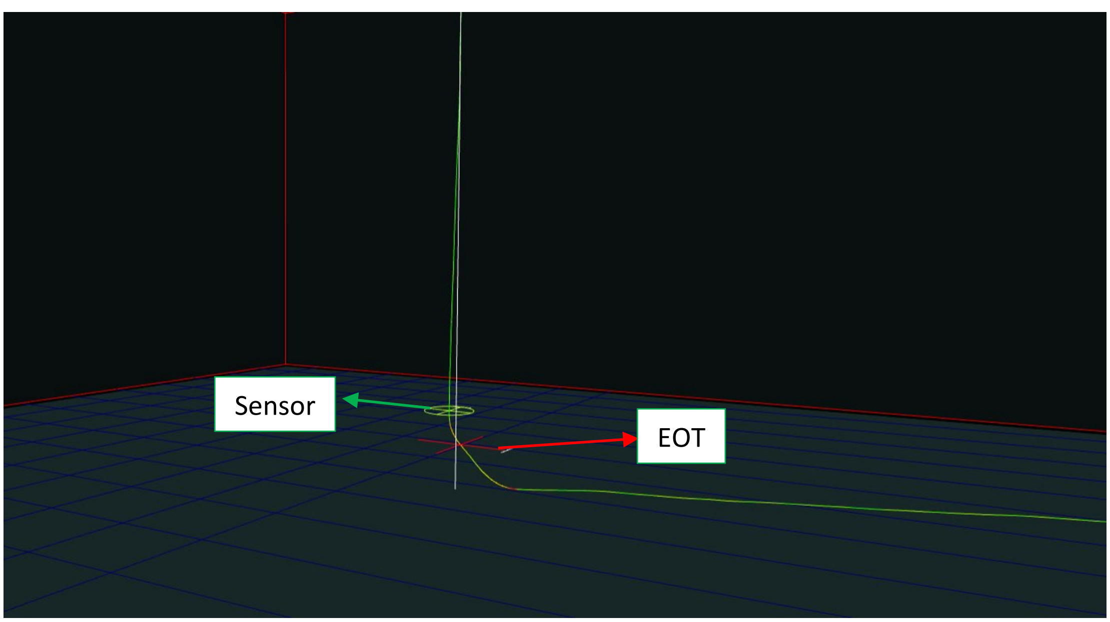


Figure 10 Well deviation survey with the Vortex Regulator

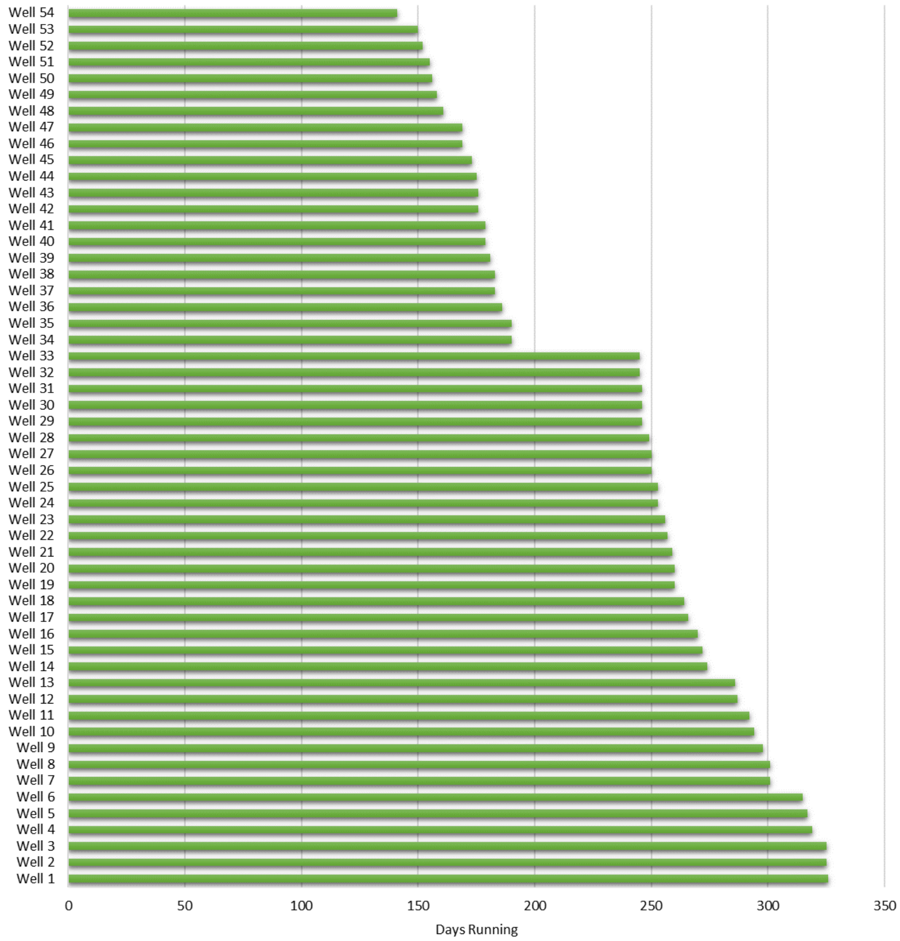


Figure 11 Wells installed with the Vortex Regulator

Figure 12 New well completed with the Vortex Regulator

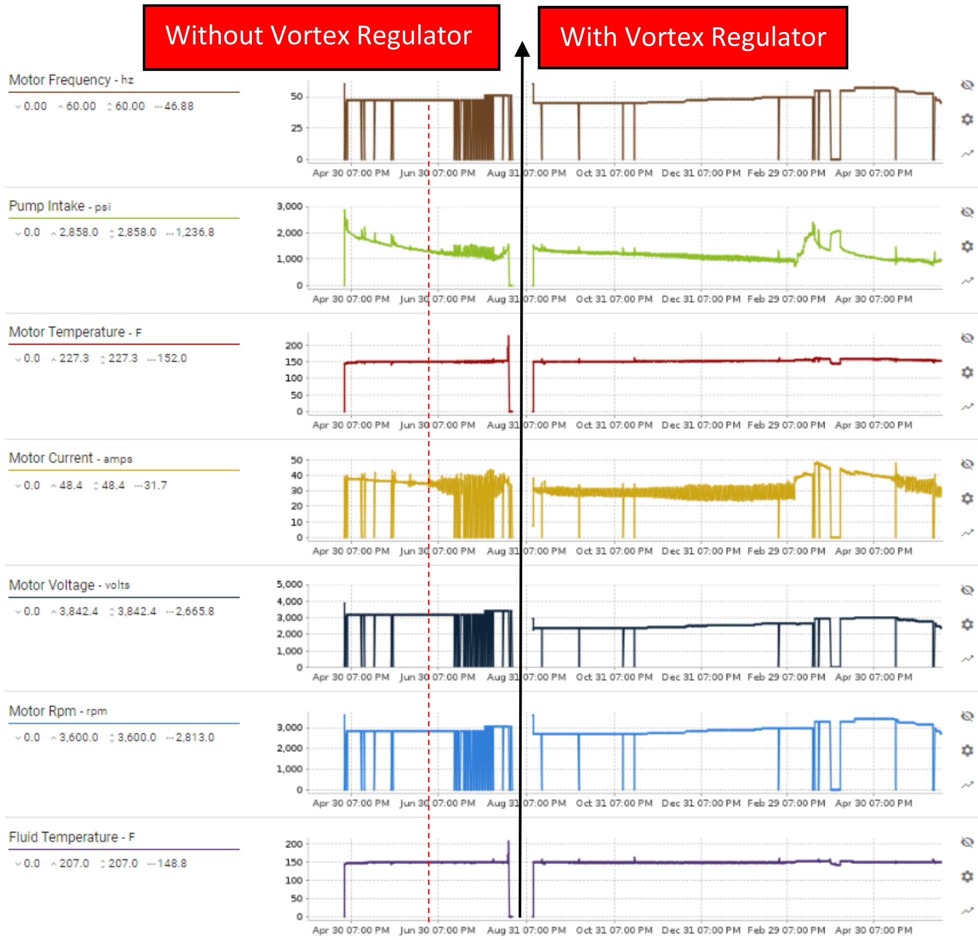


Figure 13 Well pulled and re-installed with the Vortex Regulator

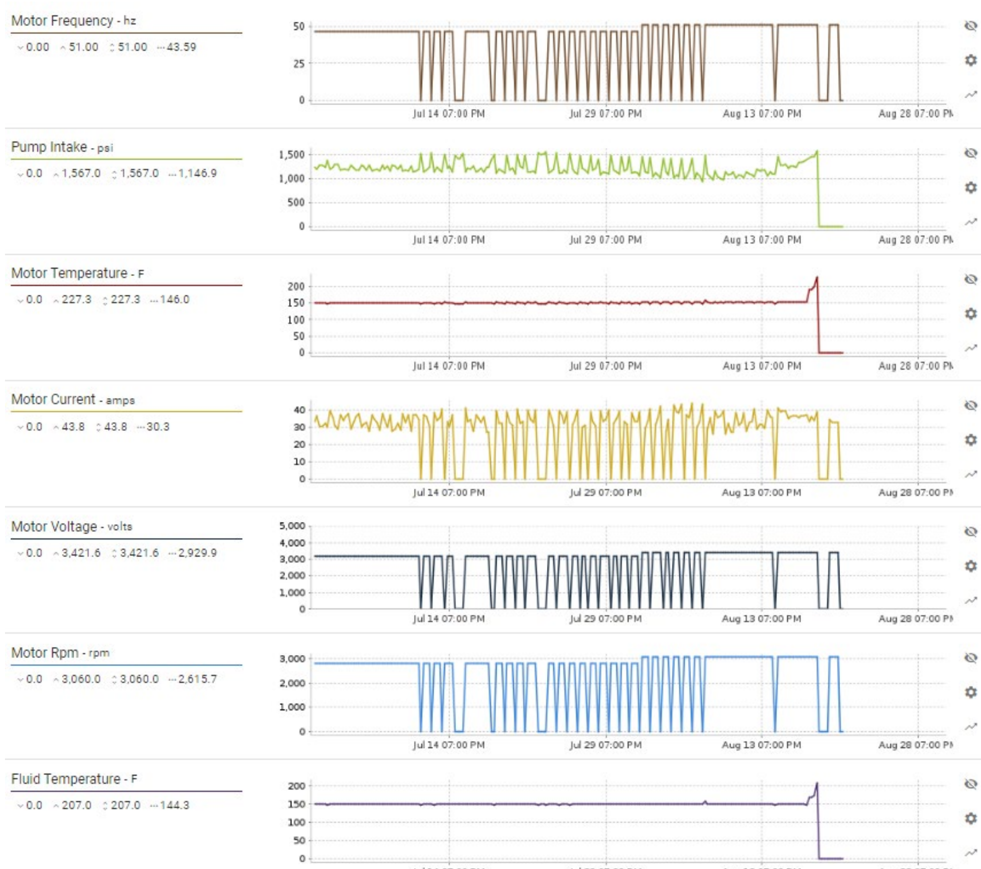


Figure 14 Pump performance before the installation of the Vortex Regulator