ELECTRICAL SUBMERSIBLE PUMP PERFORMANCE IN THE PERMIAN (DELAWARE) BASIN UNCONVENTIONAL FORMATION

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ABSTRACT

Achieving consistent, sustained run life with electrical submersible pumps (ESPs) in the unconventional play of the Permian Basin can be difficult due to a variety of harsh well conditions. More specifically, high free gas rates and abrasives contribute to the majority of well service callouts. Common operating practices are well established to mitigate some of the negative effect, such as running at lower frequencies to mitigate abrasive wear and loading motors appropriately for efficient operation. BOPCO operates several wells in the Delaware Basin and sought to further optimize ESP production in order to reduce operating expense and increase profitability. Working together with Summit ESP, a new set of operational standards for these unconventional wells was developed and initiated using a step-wise approach to analyzing individual well performance and operating parameters, then comparing results across the field as various processes and tools were implemented. In conjunction with the traditional settings, the team implemented a more robust sensor package including a discharge pressure gauge and tubing and casing transducers that are monitored by a highly skilled ESP Well Management Team to assist in all troubleshooting. Furthermore, new gas handling technologies have proven successful in improving uptime with fewer shutdowns. This dynamic combination has proven to be more efficient in preventing ESP shut downs and re-starts, invariably, increase runlife.

(1) INTRODUCTION

The challenges of producing and lifting unconventional oil and gas economically has remained the most daunting phase of unconventional oil and gas development. As the industry began developing unconventional oil and gas, the only options available for lift were the traditional artificial lift systems that were developed for conventional oil and gas applications, which were adopted and applied to unconventional wells without major changes. The result was obvious: lift systems that had performed efficiently in various environments and well conditions for decades struggled to work well in this new unconventional application. This situation described above is not just unique to ESP; however the high cost of failure repair, due to rig requirement to pull tubing in an ESP system amplified the inefficiency of the ESP performance in unconventional applications.

Unconventional wells typically follow a hyperbolic decline production curve, with high a decline rate, of between 40% and 80% in the first year. Slug flow, high free gas production, solids production (proppant, scale, paraffin), horizontal wellbore geometry, surface pad for multi-well in a cellar, and other unique unconventional well problems, are continuously pushing the limits of existing ESP systems. As it might be expected, this has significant effect on the economic viability of unconventional oil and gas production when ESP is applied to lift the wellbore fluid.

This paper presents some of the technological improvements that have been developed and applied successfully to mitigate some of the problems (especially gas locking) related to the production of unconventional oil and gas wells. This is a holistic approach: It begins with an understanding of reservoir characteristics and fluid properties, followed by equipment design and selection; active monitoring and adjusting. The presentation includes case studies of ESP performance in the Permian Delaware basin unconventional formations.

BOPCO is major oil and gas operator in the Delaware Basin, South East New Mexico (See Figure 1 and 2)

The prolific Delaware basin contains several reservoirs (conventional and unconventional) and fields (see Figure -3 & 4). Each of these reservoirs has distinct and unique rock and fluid properties. A similar reservoir may also exhibit some differences from one region of the basin to another region. Non-recognition or appreciation of these changes and complexity has resulted in poor ESP performance in some of the unconventional reservoir of the Delaware basin. Incorporating the full understanding of the reservoir into the basis of design for ESP was the main foundation to successfully improving ESP performance in the Delaware basin

(2) APPLICATIONS AND TECHNOLOGY

As mentioned above, the unconventional play of the Permian basin hosts a multitude of challenges for many forms of artificial lift. Summit ESP has worked in conjunction with BOPCO LP within the past couple of years, adapting and developing innovative solutions to alleviate these challenges.

(2.1) Inverted Shroud

One common challenge is handling free gas at the ESP intake after the reservoir has reached its bubble point, or when terminal bubble rise velocity (V_t) is greater than liquid superficial velocity (V_{SL}). One solution used to combat this challenge is the inverted shroud (Alhanati's natural separation correlation).

In conjunction with gas handling pumps and mixed flow style pump stages, the inverted shroud acts as a natural gas separator by forcing fluid to flow past a positive seal at the motor head, up and over the length of the shroud and back down to the ESP intake. The diagram on Figure 5 illustrates the flow path of fluid and gas in inverted shroud applications.

It is not uncommon for intermittent production of free gas known as gas surging or slugs to contribute to numerous shut downs in an ESP application due to gas locking and gas blocking which leads to head degradation. Although variable speed drive programs (explained in section 2.4 below) can help alleviate gas interference, it is very difficult to control excessive amounts of free gas with VSD programs alone. Another benefit to the inverted shroud is that the fluid column created in the length of the inverted shroud, can also help with gas slug ride through. The volume of fluid inside the shroud and the size of the gas slug are both contributing factors to consider for examining gas slug ride through. Furthermore, the fluid column inside the shroud can vary and is dependent upon the desired length of the shroud. The diagram in figure 6 also illustrates the position of Summit ESP's inverted shroud in relation to the downhole unit. The shroud starts at the motor head were a positive seal is created in order to prevent any fluid and/or gas from entering through the bottom of the shroud before it enters at the top of the shroud. The shroud is then attached in sections up to the desired length. This length can vary anywhere from 20' to 200'+, but must at least cover the length of the equipment up from the motor head. This is a factor because the clamp used at the top of the shroud must connect to 2 3/8" production tubing and must have enough clamping force to hold the shroud up in tension while also providing enough space for the motor lead extension to pass through.

Inverted shrouds are not the answer for every high gas application. There are a couple of considerations to make in order to ensure that the benefits of the inverted shroud are realized. The first consideration is the terminal bubble rise velocity (V_t) (Formula 1) which is the point at which the weight of the bubble becomes equal to bubble buoyancy plus the frictional force acting on the bubble. The second consideration involved in assessing inverted shroud feasibility is liquid superficial velocity. Liquid superficial velocity is used to separate multiphase flow velocities into single phase flow liquid velocities in order to understand the velocity of only one phase. In this case the gas velocity or terminal bubble rise velocity is separated from the solution to give a superficial flow velocity of the liquid alone. Liquid superficial velocity (V_{SL}) is defined by formula 2 in the appendix. If the case under consideration has a liquid superficial velocity greater than the terminal bubble rise velocity an inverted shroud is not efficient because the gas will not be forced out of solution and up the annulus before entering the pumps intake.

(2.2) High Volume Gas Separator

In an application where an inverted shroud is deemed inefficient, vortex gas separators (a more common gas separation technique) can be implemented to prepare for free gas after it has entered the pump intake. Gas separators use an inducer which creates a pressure differential between the wellbore pressure and the pressure inside the gas separator. This differential forces gas vapor out of the gas vent ports at the top of the gas separator prior to entering the pump. Depending on the manufacturer the maximum flow that the standard inducer will produce is between

1000 and 2000 BPD at 60 Hertz. When the total volume of oil, water, and gas, exceeds the maximum flow capability of a standard inducer a higher flow inducer or stage must be utilized for maximum gas separation.

(2.3) Discharge Pressure Sensor

One of the great benefits of running ESPs is the downhole data provided by ESP sensors which allows us to analyze applications where gas separation techniques do not separate the gas before it reaches the pump stages. There are a variety of capabilities and parameters that sensors produce, but one that has proven beneficial in high gas applications is the discharge pressure sensor. Because gas causes head capacity characteristics to change in centrifugal pumps, when sensors have the capability of reading discharge pressures we can capture this data. The assumption can be made that there is an increased amount of free gas at the pump intake when there is a decrease in pump discharge pressure, a decrease in flow rate, fairly constant to fluctuating well head pressure, fluctuating operating amps, a fluctuating increase in intake pressure, and an increase in motor temperature. With this information we can then determine where adjustments should be made in order to further stabilize ESP performance.

Discharge pressure sensors also help diagnose obstructions in the pumps intake or in the tubing. After calculating the expected discharge pressure produced from the pump at certain operating frequencies, we are able to analyze changes in discharge pressure in order to diagnose certain problems that are otherwise hidden. Increased discharge pressures outside of what is typically acceptable can point to obstructions in the production tubing. Symptoms of production tubing obstructions are not as easily visible without the ability to see discharge pressure from ESP sensors and mistreatment of symptoms, not only lead to wasteful intervention cost, but, can cause costly preventative damages.

(2.4) VFD Operation Modes

Although variable frequency drives (VFD’s) are not necessary for every application, they have grown to be a necessity for many of the challenging applications found in the Permian and Delaware Basin today. Combined with the other technologies mentioned in this section, variable frequency drive operating modes have drastically improved ESP performance by controlling specific operating parameters. Operating current and intake pressure parameter controls enable ESPs to target specific predetermined set points that produce the best operating performance for given applications. These controls are used to fight operational challenges caused by gas interference that is high enough to cause head degradation to the point that motor temperature issues arise. One mode used to combat gas interference is current limit (I-limit). Current limit uses predetermined target drive amperage. This amperage is maintained by the VFD by either speeding up or slowing down the frequency. For example, if the amp load decreases from the target amperage the drive will speed up the motor frequency in order to try to find the target load again. On the other hand, if the target load is exceeded the drive will slow down. Minimum and maximum frequency set points are also established and should correspond to the pumps design limitations. Current limit is helpful in fighting gas in application where the producing intake pressure is maintained below the bubble point. However, in applications where operation is possible above the bubble point, PID (proportional integral derivative) mode can be used to maintain a desired intake pressure. PID mode is also used for reservoir management or to maintain a constant bottom hole flowing pressure, in order to prevent pump off. The VFD will act much like it does in current limit mode and will speed up or slow down based on the producing intake pressure and the intake pressure target it is working to maintain. For example, if the producing intake pressure falls below the target set point the drive will slow down in order to reach the target point and if the producing intake pressure reaches a point above the target the drive will speed up to try to drop down to the target point. There must also be a frequency window set based upon the design of the ESP for both operating modes.

(2.5) Design

All the forms of gas handling and gas mitigation mentioned above contribute to the final design of the ESP system. However, they are not the only considerations that must be made to create a design that is best suited for the challenges faced in the Delaware (Permian) Basin. In order to further accommodate for these challenges, some additional steps should be taken in the design. One consideration is the style of pump stage used. Radial flow and mixed flow stage styles are both utilized in ESP equipment and their use varies depending upon how much gas, fluid and solids the well is expected to produce. These characteristics matter in the selection between radial and mixed flow style pump stages because of the differences in the size and geometry of the veins of the stages. The veins in the radial style pumps are very flat and small in comparison to a mixed flow style pumps (Figure 6). Therefore, a radial style pump is more susceptible to gas blocking and gas locking due to gas surging and slugging. When there is excessive free gas for the primary pump in the ESP string, tapering gas separators and larger flow or gas handling pumps from the intake up helps reduce gas interference in the primary pump (Figure 7).

The effectiveness of the pump stage whether a radial or mixed flow style stage can be determined by Turpin's correlation (a generally excepted formula) which is a function of flow rate and pump intake pressure (See formula 1.3). For Phi <= 1 gas interference is not predicted at the pumps intake.

A second consideration in the selection of pump stage type is the amount of solids the well is expected to produce (frac sand, paraffin, scale…). Solids, like gas, are best handled by mixed flow style pumps. This is true for much of the same reasons. The mixed flow and higher volume stages have a more sloped geometry and are able handle the solids through their wider veins and less torturous flow path so they do not throw solids at the diffuser wall at speeds as high as radial style stages do (Figure 8). For instances where using mixed flow style stages may not be enough to prevent premature failures, there are a variety of coatings that can be used to harden the stage so that it is better prepared for the harsh conditions created by the solids.

(3.0) CASES

Case 1 – Big Eddy Unit DI2 2H (Inverted Shroud)

A well in Eddy county New Mexico with a GOR over 2300 suffered frequent shuts downs due to excessive free gas causing lower than desired production. Upon failure of the competitor's equipment BOPCO and Summit ESP discussed possible solutions and examined whether the well would be a good candidate for an inverted shroud. Terminal bubble rise velocity was calculated to be 0.71982 and liquid superficial velocity was calculated to be 0.32268. Since terminal bubble rise velocity was calculated to be greater than liquid superficial velocity, an inverted shroud was deemed acceptable and was installed in conjunction with a 2500 BPD gas pump tapered to multiple 1750 BPD mixed flow pumps. After installation of the inverted shroud, the ESP system did not suffer any shut downs caused by excessive free gas and operated smoothly

Case 2 – Big Eddy Unit DI9 35H

As mentioned above under the discharge pressure section, ESPs installed with sensors are capable of providing valuable information. In the case of a well located in Eddy County New Mexico, a discharge pressure gauge provided the information needed to troubleshoot and successfully conclude that there was a plug in the tubing. The well suffered from high winding temperature shut downs which lead to a tech visiting the location. The tech started the unit and tried to get fluid to surface for just over an hour, but was unsuccessful. The tech then began to troubleshoot and found that the installed ESP equipment normally produced around 3500 PSI of discharge pressure. However, after restarting the unit the ESP system produced up to 5511 PSI of discharge pressure. While motor amps and frequency remained relatively constant, the pump intake pressure rose while the ESP was running. After discussions between Summit ESP and BOPCO LP the well was tentatively diagnosed as having a plug in the production tubing. It was decided to treat the well by pumping 30 barrels of hot oil at 190 F down the casing, then starting the ESP and continuing to pump another 45 barrels of hot oil while running in order to treat the tubing. After running the unit for about 40 minutes the motor started to cool off, discharge pressure started to even out and tubing pressure started to come up and level off at 400 PSI, confirming the diagnosis and that the treatment had successfully cleared the plug from the tubing.

Case 3 – Big Eddy Unit DI4 270H

Frequent and premature failures troubled a well located in Eddy County, New Mexico. The costs associated with pulling and installing multiple ESP systems were excessive, necessitating a change in the design of the next ESP system installed. In order to understand what was necessary to change Summit ESP examined the causes of previous failures, which were determined to be from sand and electrical component failures. In order prevent having more premature failures, it was decided to run a discharge pressure sensor in order to capture all the data possible for troubleshooting measures, a gas handling pump tapered to larger veined pumps (1000 BPD pumps to 1750 BPD pumps), and coating one of the 1750 BPD pumps with a nickel coating. As previously mentioned in the design section, there are a variety of coatings that can be applied to harden stages in order to reduce wear.

After installation of the tapered pumps, discharge pressure sensor, and one pump with nickel coated stages, the well exceeded the previous longest run by over 200 days.

Case 4 – James Ranch Unit DI1-163

Well had frequent shut down due to gas locking and gas blocking issue. This eventually resulted in premature failure. 2-Tapered Pump, Gas Handler, Upsized Pump Stages and Motor were recommended. After installation, the ESP system did not suffer any shut down caused by excessive free gas and operated smoothly. The well achieved the lowest bottom hole flowing pressure at the low frequency.

(4.0) CONCLUSION

Achieving consistent, sustained run life with electrical submersible pumps in the harsh environments found in the Delaware and Midland Basins is possible. High free gas rates and abrasives are handled through the innovative techniques and team work between BOPCO LP (The Operator) and Summit ESP (The Equipment Manufacturer). Technology improvement, such as inverted shrouds, high volume gas separators and coated stages and sensor packages valuable in the troubleshooting process. While this had not provided solutions to all the challenges related to ESP application in unconventional formation; however, the cases discussed in this paper demonstrated that when steps are taken to help mitigate these challenges, it resulted in run time and run life is improvement.

(5.0) ACKNOWLEDGEMENT

The authors express sincere appreciation for both BOPCO & Summit ESP management for their support to experiment with different options to help improve ESP Performance

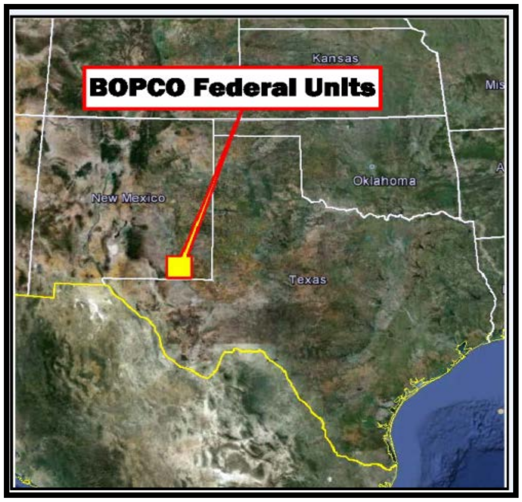

Figure 1: Map of Texas and New Mexico

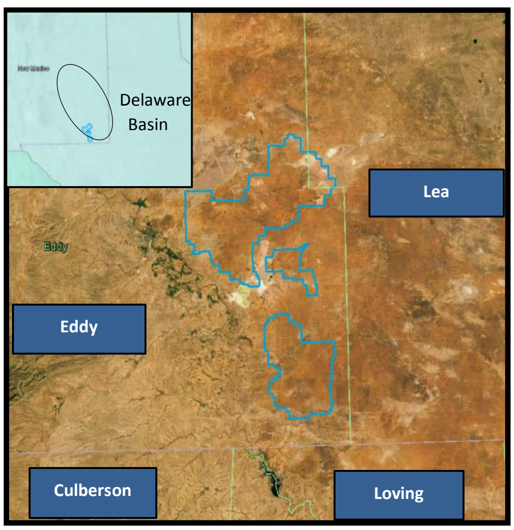

Figure 2: Map of Delaware Basin Counties

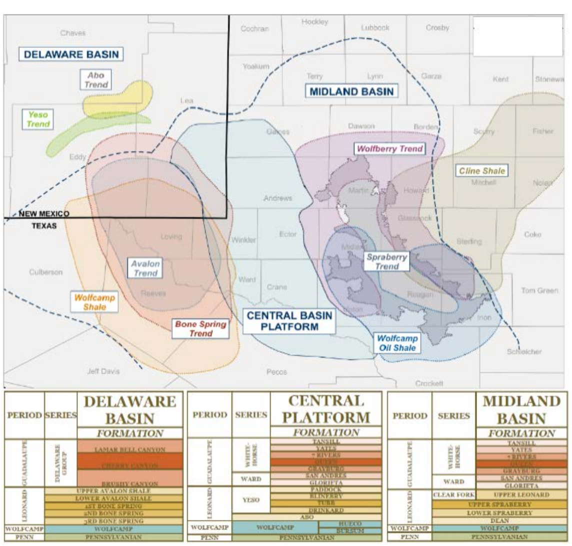

Figure 3: Map of Permian Basin and Formation

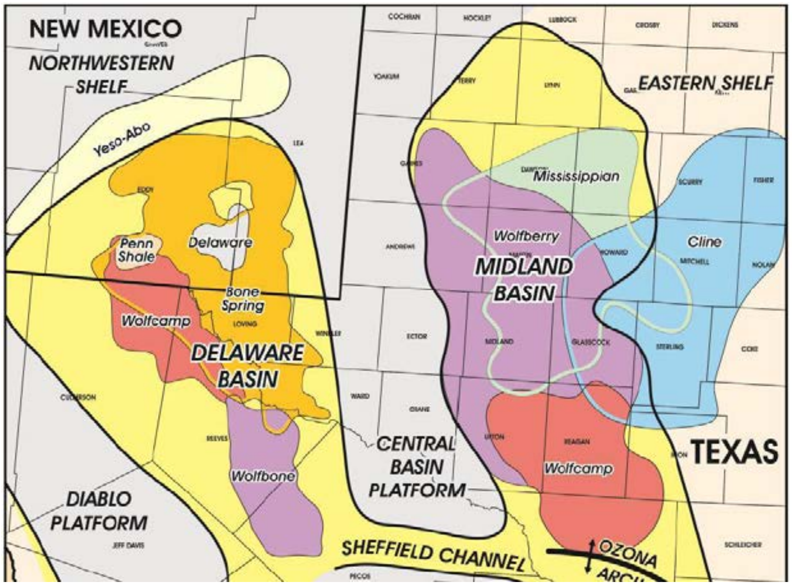

Figure 4: Map of Permian Basin and Formation

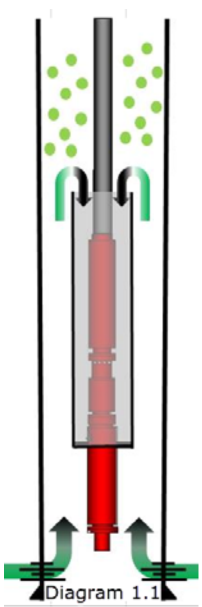

Figure 5: Inverted Shroud

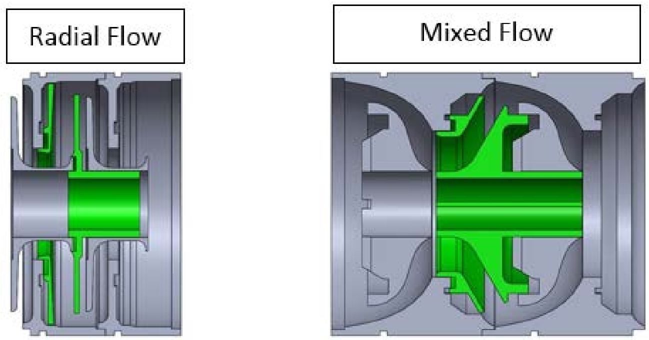

Figure 6: Radial & Mixed Flow Stages

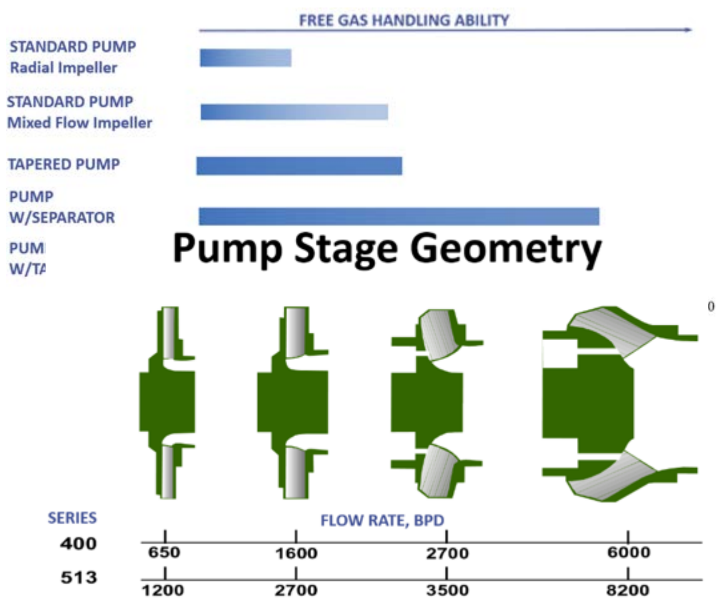

Figure 8: Pump Stage Geometry

Figure 7: Basic Free Gas Handling Capability

Formulas

$$v_t = 0.79\sqrt[4]{\frac{\sigma_l\left(\rho_l - \rho_g\right)}{\rho_l^{\,2}}}$$

Formula 1.1

Where sl = Liquid Interface Tension dyne cm, rl = Liquid Density lb/ft3 and rg = Gas Density lb/ft3.

$$V_{SL} = \frac{QLPT}{AXP}$$

Formula 1.2

Where QLPT = in situ volumetric flow rate of liquid (Cubic ft/sec) and AXP = X-sectional area of pipe (Sq ft).

Turpin's Correlation

$$\Phi = 667\frac{FreeGasBPD}{\left(PIP_{PSIA}\right)\left(BWPD + BOPD\right)}$$